LONG RUN EXPLORATION LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2012

March 18, 2013

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
BOPD	barrels of oil per day	GJ	gigajoule
NGLs	natural gas liquids	MM	Million
STB	standard tank barrels		

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.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas
BOE/d	barrel of oil equivalent per day
GCA	gas cost allowance
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
$000s	thousands of dollars
$M	thousands of dollars
$MM	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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

Where any disclosure of reserves data is made in this annual information form that does not reflect all reserves of the Corporation, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

CONVERSIONS

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

CERTAIN DEFINITIONS

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

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

"**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 voting shares in the capital of the Corporation;

"**Corporation**" or **"Long Run"** means Long Run Exploration Ltd. and, for greater certainty, prior to completion of the WestFire/Guide Arrangement on October 23, 2012 "**Corporation**" means WestFire;

"**Gross**" means:

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

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

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

"**Guide**" means Guide Exploration Ltd.;

"**Net**" means:

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

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

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

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

"Non-Voting Convertible Shares" means the non-voting convertible shares in the capital of the Corporation;

"Non-Voting Shares" means the non-voting common shares in the capital of the Corporation;

"**Orion**" means Orion Oil & Gas Corporation;

"**Orion Acquisition**" means the acquisition of Orion as described under "General Development of the Business – WestFire – 2011";

"Preferred Shares" means the first preferred shares in the capital of the Corporation, issuable in series;

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

"**Sproule Report**" means the report of Sproule dated March 6, 2013 evaluating, effective December 31, 2012 the crude oil, natural gas liquids and natural gas reserves of the Corporation;

"**Tax Act**" means the Income Tax Act (Canada);

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

"**Units**" has the meaning ascribed thereto under "General Development of the Business – Guide – 2011";

"**Warrant"** means Common Share purchase warrants of the Corporation, each of which entitles the holder to acquire 0.4167 of a Common Share at an exercise price of $3.10 until September 15, 2014 at any time after the Common Shares have achieved a 20 day volume weighted average trading price on the TSX exceeding $12.00 per Common Share;

"**WestFire**" means WestFire Energy Ltd. prior to the WestFire/Guide Arrangement; and

"**WestFire/Guide Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving WestFire, Guide and the shareholders of Guide pursuant to which, among other things, each issued and outstanding common share of Guide was acquired by WestFire for 0.4167 of a common share of WestFire and WestFire and Guide amalgamated.

CONVENTIONS

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, 2012.

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

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, management's assessment of future plans and operations, reserve and production estimates, drilling plans, activities to be undertaken in various areas, criteria and considerations in participations and acquisitions, nature of planned capital expenditures, tax horizon, timing of development of undeveloped reserves, estimated abandonment and reclamation costs and the timing thereof, weighting of production between different commodities, forecast commodity prices and exchange rates, expected land expiries and plans with respect thereto, the effect of government announcements, proposals and legislation and the expected volatility in commodity prices and stock markets may be forward looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been 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, changes in general economic and market conditions, 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 risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Long Run'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 Long Run 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 Long Run 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 Long Run operates; the timely receipt of any required regulatory approvals; the ability of Long Run 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 Long Run has an interest in to operate the field in a safe, efficient and effective manner; the ability of Long Run 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 Long Run 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 Long Run operates; and the ability of Long Run 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 affect Long Run's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), and at Long Run's website (www.longrunexploration.com). Although the forward looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward looking statements. These forward looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

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

BACKGROUND

The Corporation is an Alberta-based, intermediate oil and gas company engaged in the exploration for, and the acquisition, development and production of, oil and natural gas reserves in western Canada.

The head office of the Corporation is located at Suite 400, 250-2nd Street SW, Calgary, Alberta T2P 0C1 and its registered office is located at 2400, 525-8th Avenue SW, Calgary, Alberta T2P 1G1.

The Corporation was incorporated under the ABCA on September 14, 1999 under the name 845818 Alberta Ltd. On May 17, 2005, the Corporation filed Articles of Amendment to change its name to "WestFire Energy Ltd.". On December 13, 2007, WestFire filed Articles of Amendment to remove the "private company" restrictions including restrictions on transfer of shares and limits on the number of shareholders. On January 1, 2009, WestFire filed Articles of Amalgamation whereby WestFire amalgamated with its wholly-owned subsidiaries, WF Resources Ltd. and Racing Resources Ltd. On December 24, 2010, WestFire filed Articles of Amalgamation whereby WestFire amalgamated with its wholly-owned subsidiary, Exceed Energy Inc. On June 30, 2011, WestFire filed Articles of Amendment to create a class of non-voting convertible shares. Subsequently on June 30, 2011, WestFire amalgamated with Orion in connection with the Orion Acquisition and continued under the name of "WestFire Energy Ltd." On October 23, 2012, WestFire filed Articles of Amendment to create a class of first preferred shares and subsequently amalgamated with Guide pursuant to the WestFire/Guide Arrangement. Following the amalgamation, the Articles of WestFire were amended to change the name of WestFire to "Long Run Exploration Ltd."

The Corporation has no subsidiaries.

The Common Shares trade on the TSX under the symbol "LRE".

GENERAL DEVELOPMENT OF THE BUSINESS

Three-Year History

The following is a summary of significant events in the general development of the business of Long Run, and of WestFire and Guide as the predecessors to Long Run, during the periods indicated.

WestFire

2010

On April 30, 2010, WestFire completed a strategic Viking oil acquisition in the Provost area of Alberta for approximately $7.5 million in cash, prior to any working capital adjustments. This acquisition added an additional 85 BOE/d of production.

2011

On March 9, 2011, WestFire completed a public offering of 4,862,000 Common Shares at a price of $9.05 for gross proceeds of $44,001,100.

On June 30, 2011, WestFire acquired all of the outstanding shares of Orion in consideration for the issuance of approximately 22,527,938 Common Shares and 15,613,689 Non-Voting Convertible Shares (the "**Orion Acquisition**") and WestFire and Orion amalgamated and continued under the name WestFire Energy Ltd.

On December 9, 2011, WestFire completed an asset acquisition in its core Viking area at Redwater, Alberta, for $40.3 million in cash, prior to any working capital adjustments. This acquisition added an additional 600 BOE/d of production.

2012

On December 19, 2011 the board of directors of WestFire initiated a process to identify, examine and consider a range of strategic alternatives available to the Corporation with a view to enhancing shareholder value, resulting in the WestFire/Guide Arrangement. In connection with the WestFire/Guide Arrangement, WestFire created the Preferred Shares, changed the name of the Corporation to Long Run, Long Run and WestFire amalgamated and continued under the name "Long Run Exploration Ltd." and management of Guide became management of Long Run and the board of directors was reconstituted as described under "Directors and Officers".

Guide

2010

On March 10, 2010, the board of directors of Guide initiated a process to identify and consider strategic alternatives with a view to enhancing shareholder value. Pursuant to this process, Guide sold the majority of its interest in the Puskwa property on June 25, 2010 for approximately $134.8 million in cash before closing adjustments. These properties represented 100% of Guide's interest in a portion of its Puskwa properties and produced approximately 1.4 Mmcf/d of natural gas and 1,370 Bbl/d of crude oil and NGLs (1,600 BOE/d). Land holdings of 75,408 net acres were included in the property disposition. Net proceeds from the sale were used to reduce bank indebtedness.

On July 27, 2010, Guide announced that the special committee of the board of directors had completed its strategic review process and that the Corporation had reorganized its technical operation teams into three business units: Eastern Montney, North Peace River Arch and Kakut.

2011

On May 25, 2011, Mr. Steve Sugianto resigned as the President and Chief Executive Officer and a director of the Corporation. On August 11, 2011, William E. Andrew was appointed as the Executive Chairman and a director of Guide and Dale A. Miller was appointed as the President and a director of the Corporation.

On September 16, 2011, Guide issued an aggregate of 2,300,000 units ("**Units**") at the price of $2.81 per Unit for aggregate gross proceeds of approximately $6.5 million. Each Unit was comprised of one Class A Share of Guide and one Warrant.

On November 1, 2011, Guide changed its name from "Galleon Energy Inc." to "Guide Exploration Ltd.".

On November 15, 2011, Guide announced that Mr. William E. Andrew had been appointed as the Chief Executive Officer in addition to his role as the Executive Chairman and a director.

On November 16, 2011, Guide closed a private placement of 1,515,152 Class A Shares of Guide on a Canadian development expense "flow-through" basis pursuant to the Tax Act at a price of $3.30 per Class A Share for aggregate gross proceeds of $5,000,002. On November 24, 2011, closed a public offering of 5,634,000 Class A Shares of Guide on a Canadian exploration expense "flow-through" basis pursuant to the Tax Act at a price of $3.55 per Class A Share for gross proceeds of $20,000,700.

2012

On January 24, 2012, Guide closed a public offering 12,000,000 Class A Shares at the price of $3.05 per Class A Share for gross proceeds of $36.6 million.

On January 31, 2012, Guide closed the acquisition of certain natural gas properties located in the Boyer area of northwestern Alberta for aggregate cash consideration of $61.5 million, subject to closing adjustments and which acquisition was effective December 1, 2011.

On February 15, 2012, Guide purchased interests in certain petroleum and natural gas properties in the Peace area of Alberta for cash consideration of $6.0 million.

On March 30, 2012, the Corporation closed the disposition of properties in the Senex area of Alberta for cash consideration for $11.0 million before closing adjustments, a 3% royalty interest, and a reimbursement of the cost of a recently-completed horizontal well.

Guide and WestFire entered into an arrangement agreement dated as of August 8, 2012, which provided for the WestFire/Guide Arrangement, which closed on October 23, 2012.

Long Run

2012

On December 14, 2012, Long Run closed the disposition of properties in the Plato area of west central Saskatchewan for cash consideration of $180 million before closing adjustments and which transaction was effective November 1, 2012.

Significant Acquisitions

Other than the WestFire/Guide Arrangement described under the heading "General Development of the Business – Three Year History – Long Run", Long Run did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – Continuous Disclosure Obligations. Long Run has filed a Form 51-102F4 in respect of the WestFire/Guide Arrangement.

DESCRIPTION OF THE BUSINESS

Exploration and Development Strategy

The business plan of Long Run is to create value on a production and reserve per share basis in the oil and gas industry in western Canada. To accomplish this, Long Run has pursued and will continue to pursue an integrated growth strategy including focused exploration, controlled exploitation and strategic acquisitions within its geographic project areas in the Peace River Arch region of the Western Canadian Sedimentary Basin.

Near term development will be to narrow the focus on oil, continue to expand the land base for future exploration and development, and maintain a strong focus on cost control and efficiencies. The Corporation has focused its near term development efforts on the oil rich Triassic sediment package over its large land position in the Peace River Arch with particular emphasis on its emerging Montney oil resource play at Normandville/Girouxville.

Long Run has assembled large land blocks close to gas infrastructure and crude oil processing facilities. Long Run has invested in natural gas and crude oil infrastructure in its key areas so as to obtain operatorship and control of the facilities. Additionally, Long Run has pursued and will continue to pursue strategic asset and corporate acquisitions of crude oil and natural gas properties.

Management of Long Run 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 Long Run's activities as opportunities arise.

In reviewing potential participations or acquisitions, Long Run will consider criteria including the following:

- the ratio of risk to reward;
- whether the opportunity has an anticipated pay-back period of less than two years;
- whether the opportunity has an anticipated rate of return of greater than 30%;
- whether the area possesses geological opportunities that have multi-zone potential;
- whether the prospects have reservoir characteristics that are familiar to management;

- the amount of potential for additional reservoir development;
- the degree of near term market access;
- whether sufficient infrastructure exists to provide for increased activity;
- whether there are investments in a sufficient number of properties to reduce risk;
- whether the properties exhibit a reserve life of at least six years;
- the possibility of Long Run becoming the operator; and
- the ability of Long Run to enhance the value of acquired properties through additional exploitation efforts, including improved production practices, additional development drilling, completion and tie-in of capped wells and improved marketing arrangements.

In addition to the above criteria, in circumstances where Long Run seeks to acquire significant assets with proven and probable reserves, prior to the investment decision being finalized, Long Run will generally obtain an independent engineering report (whether from the vendor of such assets or otherwise) relating to such proven and probable reserves.

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

Specialized Skill and Knowledge

Drawing on significant experience in the oil and gas business, Long Run's management team has a demonstrated track record of bringing together all of the key components to a successful acquisition and development company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Long Run to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

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

The oil and natural gas industry is intensely competitive and Long Run is required to compete with a substantial number of other entities which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex.

Long Run will attempt to enhance its competitive position by operating in areas where its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. Management believes that Long Run will be able to explore and develop new production and reserves with the objective of increasing its cash flow and reserve base. See "*Risk Factors – Competition*".

Cycles

The Corporation's business is generally cyclical. The exploration and development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including freeze up and break up affect access in certain circumstances. See "*Risk Factors – Seasonality*".

Environmental Protection

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

Employees

As at December 31, 2012, Long Run had 107 full time employees and 13 consultants located at its office in Calgary. In addition, Long Run had 38 full time employees and 75 contract operators in various field locations.

Environmental, Health and Safety Policies

Environmental protection and employee health and safety are core values recognized and supported by the Corporation. The Corporation actively supports these areas by integrating the essential principles and practices through its environmental management systems and employee occupational health and safety programs. The Corporation ensures policies and procedures are fully integrated with and within all operating units by advising and educating employees, suppliers and contractors in the safe use, transportation, storage and disposal of products and materials. The Corporation promotes and enhances safety and environmental awareness and protection through the implementation and communication of the Corporation's environmental management and employee occupational health and safety programs policies and procedures. Effective committee structures are established in the Corporation's operations to allow for employee participation and development of corporate policies and programs which provide employees with job orientation, training, instruction and supervision necessary to assist them in conducting their activities in an environmentally responsible and safe manner.

The Corporation develops emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities it operates in order to ensure prompt response to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities to identify, assess and minimize environmental risks and operational exposures. The Corporation conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Accurate documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to ensure the objectives of the policies and programs are achieved.

The Corporation also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Corporation's environmental and occupational health and safety management systems are designed to identify, prevent and control such risks in the Corporation's business and ensure immediate action is taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits.

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 6, 2013. The effective date of the Statement is December 31, 2012 and the preparation date of the Statement is March 6, 2013.

Disclosure of Reserves Data

The Corporation engaged Sproule to provide an evaluation of the Corporation's proved and proved plus probable reserves as at December 31, 2012. The reserves data set forth below (the "**Reserves Data**") is based upon the Sproule Report dated March 6, 2013. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. The Reserves Committee of the Board of Directors has reviewed and approved the Sproule Report. The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

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

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

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MBOE)	Net (MBOE)
Proved Developed										
Producing	7,667	6,571	829	713	132,183	119,131	2,421	1,566	32,947	28,705
Non-Producing	233	205	159	130	16,103	13,697	293	184	3,368	2,802
Proved										
Undeveloped	8,942	7,965	553	469	42,908	38,823	695	504	17,342	15,408
Total Proved	16,842	14,741	1,540	1,312	191,194	171,651	3,409	2,254	53,657	46,915
Probable	11,719	9,856	1,254	1,061	90,234	79,641	1,497	1,003	29,508	25,193
Total Proved plus Probable	28,561	24,597	2,794	2,373	281,428	251,292	4,905	3,257	83,165	72,109

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 ($M)	5 ($M)	10 ($M)	15 ($M)	20 ($M)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 ($M)	5 ($M)	10 ($M)	15 ($M)	20 ($M)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE)
Proved Developed											
Producing	773,203	639,904	552,564	490,061	442,829	773,203	639,904	552,564	490,061	442,829	19.25
Non-Producing	59,791	44,491	35,243	29,077	24,677	59,791	44,491	35,243	29,077	24,677	12.58
Proved Undeveloped	308,144	212,822	151,919	109,868	79,236	308,144	212,822	151,919	109,868	79,236	9.86
Total Proved	1,141,138	897,217	739,726	629,007	546,742	1,141,138	897,217	739,726	629,007	546,742	15.77
Probable	789,387	526,439	379,381	287,140	224,942	628,527	426,660	312,662	240,210	190,672	15.06
Total Proved plus Probable	1,930,525	1,423,65 6	1,119,107	916,147	771,684	1,769,665	1,323,876	1,052,388	869,216	737,414	15.52

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($M)	ROYALTIES ($M)	OPERATING COSTS ($M)	DEVELOPMENT COSTS ($M)	WELL ABANDONMENT COSTS ($M)	FUTURE NET REVENUE BEFORE INCOME TAXES ($M)	INCOME TAXES ($M)	FUTURE NET REVENUE AFTER INCOME TAXES ($M)
Total Proved	2,812,392	268,676	1,015,698	374,777	12,102	1,141,138	-	1,141,138
Total Proved plus Probable	4,618,999	497,758	1,608,413	562,993	19,310	1,930,525	160,860	1,769,665

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($M)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	415,955	$23.94/Bbl
	Heavy Oil (including solution gas and other by-products)	32,859	$20.67/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	267,440	$1.60/Mcf
	Other Income	23,472	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	676,415	$22.66/Bbl
	Heavy Oil (including solution gas and other by-products)	52,906	$19.33/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	365,307	$1.54/Mcf
	Other Income	24,478	

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Sproule Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is 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, specifically the forecast prices and costs.

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:

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

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

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report were an average of the forecast prices, inflation and exchange rates as published by Sproule, GLJ Petroleum Consultants Ltd., and McDaniel & Associates Consultants Ltd. as at December 31, 2012 (the "Consultants' Average Forecast Prices"), as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	OIL WTI Cushing Oklahoma ($US/Bbl)	Edmonton Oil Price 40° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	Natural Gas Alberta Spot Gas Price ($Cdn/Mcf)	Pentanes Plus Edmonton ($Cdn/Bbl)	Butanes Price Edmonton ($Cdn/Bbl)	Inflation Rates(1) %/Year	Exchange Rate(2) ($US/$Cdn)
Forecast								
2013	90.71	85.68	62.75	3.35	94.89	64.19	1.83	1.00
2014	91.64	90.61	67.58	3.80	96.57	69.01	1.83	1.00
2015	92.30	91.60	68.62	4.18	95.97	70.91	1.83	1.00
2016	96.17	95.48	72.15	4.71	100.08	73.88	1.83	1.00
2017	97.29	96.59	72.98	5.12	101.22	74.74	1.83	1.00
2018	98.44	97.71	73.81	5.36	102.41	75.60	1.83	1.00
2019	99.94	99.21	74.95	5.45	104.00	76.76	1.83	1.00
2020	101.76	101.03	76.33	5.57	105.88	78.17	1.83	1.00
2021	103.61	102.88	77.74	5.67	107.82	79.60	1.83	1.00
2022	105.54	104.81	79.22	5.77	109.85	81.11	1.83	1.00
2023	107.46	106.69	80.64	5.87	111.82	82.57	1.83	1.00
2024	109.43	108.65	82.11	5.99	113.85	84.10	1.83	1.00
2025+	Escalated oil, gas and product prices at 1.83% per year thereafter							

Notes:

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

4. Weighted average historical prices realized, before transportation and financial derivative contracts, by the Corporation for the year ended December 31, 2012, were $2.80/Mcf for natural gas, $81.15/Bbl for light crude oil, $61.37/Bbl for heavy oil and $72.28/Bbl for NGLs.

5. Well abandonment costs have only been included for undeveloped wells with reserves assigned. Additional abandonment costs associated with existing wells and lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

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

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

8. The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis and utilizing the Corporation's tax pools. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

Reconciliations of Changes in Gross Reserves

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2011[(1)]	12,678	8,301	20,979	741	397	1,138
Extensions	232	1,177	1,409	15	44	59
Improved Recovery	1,081	521	1,602	69	12	81
Technical Revisions	(192)	(2,301)	(2,493)	(69)	(100)	(169)
Discoveries	-	-	-	-	-	-
Acquisitions	9,283	7,095	16,379	1,213	986	2,199
Dispositions	(3,623)	(3,139)	(6,762)	(14)	(50)	(64)
Economic Factors	(166)	65	(101)	(99)	(35)	(134)
Production	(2,453)	-	(2,453)	(317)	-	(317)
December 31, 2012	16,842	11,719	28,561	1,540	1,254	2,794

	NATURAL GAS LIQUIDS			NATURAL GAS			TOTAL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
December 31, 2011[(1)]	4,824	1,604	6,428	63,934	24,496	88,430	28,899	14,385	43,283
Extensions	1	3	3	150	753	903	273	1,349	1,622
Improved Recovery	3	1	4	770	336	1,106	1,281	590	1,871
Technical Revisions	(1,811)	(601)	(2,413)	(16,269)	(8,515)	(24,784)	(4,783)	(4,422)	(9,205)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	846	528	1,373	155,665	74,615	230,280	37,286	21,045	58,331
Dispositions	(32)	(20)	(52)	(1,635)	(1,175)	(2,810)	(3,942)	(3,405)	(7,347)
Economic Factors	(52)	(17)	(69)	(1,329)	(276)	(1,605)	(538)	(34)	(571)
Production	(369)	-	(369)	(10,092)	-	(10,092)	(4,820)	-	(4,820)
December 31, 2012	3,409	1,497	4,906	191,194	90,234	281,428	53,657	29,509	83,165

Note:

(1) Opening balance at December 31, 2011 are the reserves of WestFire at December 31, 2011 as evaluated by GLJ Petroleum Consultants Ltd.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the remaining proved undeveloped reserves and the remaining probable undeveloped reserves, each by product type, attributed to the Corporation's assets for the years ended December 31, 2012, 2011, 2010 and 2009 based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2009	912	952	170	170	444	461	0	0
2010	1,316	2,672	349	379	868	1,492	10	13
2011	6,293	7,962	30	155	15,690	16,584	1551	1558
2012	5,873	8,942	486	553	38,371	42,908	327	695

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2009	1,767	2,035	415	496	1,997	2,634	17	22
2010	2,634	3,480	124	361	1,129	2,075	19	28
2011	5,636	6,937	45	214	8,077	9,397	535	554
2012	6,660	8,727	731	853	33,682	40,435	322	888

In general, once proved and/or probable reserves are identified, they are included in Long Run's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within three years; however these locations will continue to be re-evaluated to assess their relative economic merits when compared to other projects available to the Corporation. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, royalties, 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).

See "Principal Properties", "Future Development Costs" and "Other Oil and Gas Information – Capital Expenditures" for a description of the Corporation's exploration and development plans and expenditures.

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 and pricing 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.

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

Future Development Costs

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

	Forecast Prices and Costs ($MM)	
Year	Proved Reserves	Proved Plus Probable Reserves
2013	158	190
2014	98	164
2015	51	104
2016	4	40
2017	0	0
Thereafter	64	65
Total Undiscounted	375	563

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

Other Oil and Gas Information

Principal Properties

The Corporation is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of the Corporation's current operations are in the provinces of Saskatchewan and Alberta.

The following is a description of the Corporation's oil and natural gas properties as at December 31, 2012, unless otherwise stated. The reserve amounts stated are gross reserves, as at December 31, 2012 based on forecast costs and prices as evaluated in the Sproule Report (see "Reserves Data"). Unless otherwise specified, gross and net acres and well count information are as at December 31, 2012. **The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.**

Peace Area – Northwest Alberta

The Peace Area is located in Townships 73 to 82, and Ranges 17W5M to 01W6M, and is approximately 80 kilometers northeast of Grande Prairie, Alberta.

In addition to several minor properties, this area includes the Normandville, and Girouxville, Montney oil projects. These projects are characterized by a large, regional oil and gas accumulation with thick pay intervals of up to 30 meters, at approximately 950 meters vertical depth. Long Run has identified, delineated, and initiated development of a fairway that is approximately 50 kilometers long and ten kilometers wide. Development is expected to occur via horizontal drilling with a density of between four and eight wells per section, targeting oil. Enhanced recovery potential also exists in this field and will be evaluated during 2013. Approximately 90% of this area is year-round accessible for drilling, seismic and construction projects.

In addition to the Montney horizon, the area is characterized by multi-zone hydrocarbon-bearing formations at depths ranging from 300 meters to 2,400 meters. Long Run has identified eleven additional target zones: Paddy, Notikewin, Falher, Bluesky, Gething, Charlie Lake, Debolt, Wabamun, Beaverhill Lake, Slave Point and Granite Wash.

Long Run operates, transports, and processes substantially all of its production in the Peace Area.

During 2012, subsequent to acquiring these assets, Long Run drilled five (5.0 net) wells and cased all of these, within the Peace Area. Long Run plans to drill up to 50 oil wells in the area in 2013.

At December 31, 2012, the Corporation held an interest in 302,705 gross acres (283,397 net acres) of undeveloped land in the Peace Area.

The Sproule Report assigns total proved plus probable reserves of 15.9 Mmbbls of oil and NGLs, and 111.9 Bcf of natural gas, as at December 31, 2012 within the Peace Area.

Redwater Area – East Central Alberta

The Redwater Area is located in Townships 54 to 58, and Ranges 19 to 23W4M, approximately 50 kilometers northeast of the city of Edmonton, Alberta.

Long Run's activities in the Redwater Area are directed primarily toward light oil in the Viking formation. Development is occurring using horizontal drilling at a density of up to 16 wells per section. Long Run will begin to evaluate the potential for enhanced recovery within this play during 2013.

Long Run processes, operates, and transports substantially all of its production in the Redwater area.

At December 31, 2012, the Corporation held an interest in 81,416 gross acres (70,516 net acres) of undeveloped land in the Redwater Area.

The Sproule Report assigns total proved plus probable reserves of 12.7 Mmbbls of oil and NGLs, and 26 Bcf of natural gas, as at December 31, 2012 within the Redwater Area.

Boyer Area – Northwest Alberta

The Boyer Area is located in Townships 100 to 109, and Ranges 20W5M to 04W6M, immediately south of the town of High Level, Alberta.

In the Boyer Area, Long Run produces natural gas from the Cretaceous Bluesky and Gething formations, at depths ranging from 200 meters to 600 meters. Long Run's holdings cover a fairway that is approximately 100 kilometers long and 30 kilometers wide. Average drilling density is currently less than two vertical wells per section. Opportunity exists to continue development of this field with further infill drilling and using horizontal wells.

No wells were drilled in this area by Long Run during 2012. Significant drilling activity can be undertaken by Long Run with an improvement in natural gas prices.

At December 31, 2012, the Corporation held an interest in 121,864 gross acres (121,544 net acres) of undeveloped land in the Boyer Area.

The Sproule Report assigns total proved plus probable reserves of 87.3 Bcf of natural gas, as at December 31, 2012 within the Boyer Area.

Kaybob Area – West Central Alberta

The Kaybob Area is located in Townships 58 to 66 and Ranges 13 to 22W6M, approximately 220 kilometers northwest if the city of Edmonton, Alberta.

The majority of Long Run's production in the Kaybob Area is natural gas, natural gas liquids, and condensate from the Devonian Beaverhill Lake formation, at 3,200 meters depth. Long Run holds a 90.7% working interest in the Kaybob South Beaverhill Lake Unit No. 1 ("Unit"), and is the operator of this Unit.

No wells were drilled in this area by Long Run during 2012. Long Run has identified opportunity to drill additional infill wells within the Unit with an improvement in natural gas prices.

At December 31, 2012, the Corporation held an interest in 8,080 gross acres (6,344 net acres) of undeveloped land in the Kaybob Area.

The Sproule Report assigns total proved plus probable reserves of 3.5 Mmbbls of oil and NGLs, and 28.7 Bcf of natural gas, as at December 31, 2012 within the Kaybob Area.

Oil and Gas Wells

The following table sets forth the number and status of oil and gas wells in which the Corporation had a working interest as at December 31, 2012.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	757	653.3	212	181.2	1,398	1,349.8	386	318.4
Saskatchewan	24	24.0	70	70.0	0	0.0	34	33.1
Total	781	677.3	282	251.2	1,398	1,349.8	420	351.5

Note:

(1) This table does not include water source wells, injection wells, abandoned wells or wells which have never produced. Producing wells are based on public data status.

Land Holdings Including Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2012.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	1,084,646	957,591	864,248	747,394	1,948,894	1,704,985
Saskatchewan	15,767	14,692	16,247	15,216	32,014	29,908
British Columbia	-	-	-	-	-	
Total	1,100,413	972,283	880,495	762,609	1,980,908	1,734,893

Long Run calculates both its gross and net acres on a per lease basis.

The Corporation expects that rights to explore develop and exploit 91,861 net acres of its undeveloped land holdings will expire by December 31, 2013, a portion of which may be continued by drilling. Long Run plans to drill or submit application to continue selected portions of the above acreage.

Forward Contracts and Marketing

Long Run's crude oil and natural gas production is sold to major Canadian marketers on a spot pricing basis. The contract term is generally a 30 day evergreen in the case of crude oil and up to a one year for natural gas and NGLs. Long Run may periodically hedge the price of a portion of its crude oil and natural gas production. The Corporation contracts natural gas transportation for periods of up to four years at volumes based on estimated production from each property.

As of the date hereof, the Corporation has the following crude oil and natural gas financial derivatives in place:

Natural Gas:	Volume	Pricing
Costless Collars:		
January 1, 2013 – December 31, 2013	3,000 GJ/d	CDN $2.80 - $3.40/GJ
January 1, 2013 – December 31, 2013	7,000 GJ/d	CDN $3.15 - $3.60/GJ
Fixed Price:		
January 1, 2013 – October 31, 2013	5,000 GJ/d	CDN $4.20/GJ
January 1, 2013 – December 31, 2013	5,000 GJ/d	CDN $3.00/GJ
January 1, 2013 – December 31, 2013	5,000 GJ/d	CDN $3.50/GJ
January 1, 2013 – December 31, 2013	10,000 GJ/d	CDN $3.60/GJ
April 1, 2013 – December 31, 2013	10,000 GJ/d	CDN $4.05/GJ
Call Swaption:		
January 1, 2014 – December 31, 2014	10,000 GJ/d	CDN $4.00/GJ

Crude Oil:	Volume	Pricing
Costless Collars:		
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $85.00-$94.00/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $85.00-$94.25/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $85.00-$96.00/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $98.00-$102.00/Bbl
February 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $90.00-$102.00/Bbl
Fixed Price:		
January 1, 2013 – December 31, 2013	600 Bbl/d	WTI CDN $97.05/Bbl

January 1, 2013 – December 31, 2013	1,600 Bbl/d	WTI CDN $100.30/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI US$85.00/Bbl
April 1, 2013 – December 31, 2013	1,000 Bbl/d	WTI CDN $96.75/Bbl
Calls:		
January 1, 2013 – March 31, 2013	1,527 Bbl/d	WTI US $85.00/Bbl
January 1, 2013 – December 31, 2013	73 Bbl/d	WTI US $100.00/Bbl
January 1, 2014 – December 31, 2014	500 Bbl/d	WTI US $100.00/Bbl
April 1, 2013 – December 31, 2013	200 Bbl/d	WTI US $85.00/Bbl
January 1, 2014 – December 31, 2014	500 Bbl/d	WTI US $85.00/Bbl
January 1, 2015 – December 31, 2015	500 Bbl/d	WTI US $85.00/Bbl
Call Swaptions:		
January 1, 2014 – August 31, 2014	980 Bbl/d	WTI US $85.00/Bbl
September 1, 2014 – April 30, 2015	1,000 Bbl/d	WTI US$85.00/Bbl
September 1, 2014 – April 30, 2015	1,000 Bbl/d	WTI US$90.00/Bbl

Interest Rate Swap:

Notional Amount CAD $75 million — Term: February 6, 2012 – January 5, 2014
Fixed rate 1.190% - Floating rate is reset against CAD-BA-CDOR monthly

Electricity:	Volume	Pricing
January 1, 2013 – December 31, 2014	1.5 MW/h	CDN $67.75 MW/h
January 1, 2013 – December 31, 2014	1.5 MW/h	CDN $54.35 MW/h
January 1, 2015 – December 31, 2016	3.0 MW/h	CDN $49.50 MW/h

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. 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. The Corporation has approximately 3,452.2 net wells including water source, injection and standing wells for which it expects to incur abandonment and reclamation costs. The abandonment and reclamation obligation included in the Corporation's financial statements differs from the amount deducted in the reserves evaluation, as the Sproule Report forecasts abandonment costs only for undeveloped wells, scheduled to be drilled in the future and no allowance was made for reclamation of existing wellsites or the abandonment and reclamation of any facilities in the Sproule Report. The following table sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue as provided in the Sproule Report:

Forecast Prices and Costs ($M)

Year	Total Proved Abandonment Costs (Undiscounted)	Total Proved plus Probable Abandonment Costs (Undiscounted)
2013	61	61
2014	83	0
2015	37	116
Thereafter	11,171	17,316
Total Undiscounted	11,352	17,493
Total Discounted @ 10%	3,028	3,593

The asset retirement obligations recorded in the Corporation's financial statements result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The

Corporation estimates the total undiscounted amount of cash flows required to settle its asset retirement obligation is approximately $349 million, which will be incurred over the next 40 years.

Tax Horizon

The Corporation does not expect to pay current income tax for the 2013 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that, based on its current business plan, the Corporation will not begin paying current income taxes for a number of years.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2012:

	($M)
Property Acquisition Costs	
Proved properties	-
Undeveloped properties	15,157
Exploration costs	9,365
Development costs	185,888
Dispositions	(178,241)
Corporate Acquisitions	
WestFire/Guide Arrangement	422,520
Total	454,689

Note:

(1) Capital expenditures in the table are the capital expenditures of WestFire prior to completion of the WestFire/Guide Arrangement on October 23, 2012 and of Long Run thereafter.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2012:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Oil	3.0	3.0	129.0	117.4
Heavy Oil	-	-	-	-
Natural Gas	-	-	-	-
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total	3.0	3.0	129.0	117.4

Note:

(1) Wells in the table are those of WestFire prior to completion of the WestFire/Guide Arrangement on October 23, 2012 and of Long Run thereafter.

See "Principal Properties" for a description of the Corporation's exploration and development plans.

Long Run's primary area of exploration and development activity is in the Peace area and Redwater area of Alberta. Long Run's key growth areas are located in these areas. In 2012, five (5.0 net) wells were drilled in the Peace area, 63 (59.4 net) wells were drilled in the Redwater area. The majority of capital expenditures in 2013 are currently planned to be invested in these two areas. See "Principal Properties".

Production Estimates

The following tables disclose, by product, and by area, the total volume of the Corporation's gross production estimated by Sproule for 2013 in the estimates of future net revenue from gross proved and gross probable reserves disclosed under "Disclosure of Reserves Data".

From Gross Proved Reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Peace	4,638	-	23,749	203	8,799	38%
Redwater	3,708	-	7,448	40	4,989	22%
Boyer	-	-	19,046	-	3,174	14%
Kaybob	14	-	8,818	980	2,463	11%
Other	336	1,219	10,613	126	3,450	15%
Total	8,695	1,219	69,674	1,349	22,875	100%

From Gross Probable Reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Peace	546	-	3,821	34	1,217	50%
Redwater	367	-	337	2	425	17%
Boyer	-	-	268	-	45	2%
Kaybob	-	-	237	19	59	2%
Other	206	99	2,227	20	696	29%
Total	1,119	99	6,891	75	2,442	100%

Production History

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

	Quarter Ended			
	2012			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[1]				
Light and Medium Crude Oil (Bbls/d)	9,125	6,057	6,310	4,702
Heavy Oil (Bbls/d)	1,538	1,128	868	518
Gas (Mcf/d)	56,453	18,214	19,548	16,288
NGLs (Bbls/d)	1,332	669	1,113	913
Combined (BOE/d)	21,405	10,890	11,549	8,848
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/Bbl)	73.47	77.45	80.04	87.20
Heavy Oil ($/Bbls)	56.29	58.07	61.76	69.52
Gas ($/Mcf)	3.08	2.27	1.79	2.11
NGLs ($/Bbls)	65.90	62.80	74.90	84.47
Combined ($/BOE)	48.00	57.94	58.98	64.67

	Quarter Ended 2012 Dec. 31	Sept. 30	June 30	Mar. 31
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	11.70	7.87	8.73	10.30
Heavy Oil ($/Bbls)	9.68	5.30	11.22	8.74
Gas ($/Mcf)	0.37	0.20	0.24	0.29
NGLs ($/Bbls)	24.11	21.38	16.97	23.00
Combined ($/BOE)	8.17	6.58	7.65	8.89
Operating Expenses				
Light and Medium Crude Oil ($/Bbls)	10.00	13.65	12.85	12.63
Heavy Oil ($/Bbls)	13.48	34.54	31.44	38.36
Gas ($/Mcf)	2.25	3.34	2.60	2.71
NGLs ($/Bbls)	13.82	20.07	14.74	15.87
Combined ($/BOE)	11.78	18.20	15.35	15.86
Netback Received(2)				
Light and Medium Crude Oil ($/Bbls)	51.77	55.93	58.46	64.27
Heavy Oil ($/Bbls)	33.13	18.23	19.10	22.42
Gas ($/Mcf)	0.46	(1.28)	(1.05)	(0.89)
NGLs ($/Bbls)	27.97	21.35	43.19	45.60
Combined ($/BOE)	28.05	33.16	35.98	39.92

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties, transportation costs and operating costs from revenues.
(3) Amounts in the table are for WestFire prior to completion of the WestFire/Guide Arrangement on October 23, 2012 and for Long Run thereafter.

The following table indicates the Corporation's average daily production from its important areas for the year ended December 31, 2012:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)
Redwater	4,294	47	8,459	52	5,803
Peace	927	-	4,280	42	1,682
Boyer	-	-	3,349	-	558
Kaybob	17	-	8,041	860	2,217
West Central Saskatchewan	1,243	12	612	7	1,364
Other	73	956	2,938	46	1,565
Total	6,554	1,015	27,679	1,007	13,189

The Corporation's production for the year ended December 31, 2012 was 50% light quality crude oil (32° API or greater), 8% heavy oil, 35% natural gas, and 7% liquids.

For the twelve months ended December 31, 2012, approximately 88% of the Corporation's gross revenue was derived from crude oil and liquids production, 10% was derived from natural gas production and 2% was derived from sulphur production.

DIVIDEND POLICY

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

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue and unlimited number of Common Shares, an unlimited number of Non-Voting Shares, an unlimited number of Non-Voting Convertible Shares and an unlimited number of Preferred Shares, issuable in one or more series. The following is a description of the rights, privileges, restrictions and conditions attaching to the share capital of the Corporation. As at March 15, 2013, there were an aggregate of 110,107,152 Common Shares and an aggregate of 15,512,858 Non-Voting Convertible Shares issued and outstanding. There are no Non-Voting Shares or Preferred Shares outstanding.

Common Shares

The holders of Common Shares are entitled to one vote for each Common Share held on all matters to be voted on by such holders and are entitled to receive such dividends as may be declared by the board of directors of the Corporation on such shares subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes of shares of the Corporation ranking in priority thereto in respect of dividends. Holders of Common Shares are entitled, in the event of any liquidation, dissolution or winding-up of the Corporation, whether voluntarily, or in the event of other distribution of the assets of the Corporation among the shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share ratably, together with the holders of the Non-Voting Shares and of any shares of any other class ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Non-Voting Shares

The holders of Non-Voting Shares are entitled to receive notice and attend shareholder meetings provided that, except as required by law, shall not be entitled to vote on any matter. The holders of Non-Voting Shares are entitled to receive such dividends as may be declared by the board of directors of the Corporation on the Non-Voting Shares subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of the Corporation ranking in priority to the Non-Voting Shares, provided that no dividend may be declared in respect of, or any other benefit conferred upon holders of, Common Shares unless concurrently therewith the same dividend in respect of, or the same benefits conferred upon holders of, Non-Voting Shares. The holders of the Non-Voting Shares are entitled, in the event of any liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or in the event of other distribution of assets of the Corporation among the shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share ratably, together with the holder of the Common Shares and of any shares of any other class ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution

Neither the Common Shares nor the Non-Voting Shares may be subdivided, consolidated, reclassified or otherwise changed unless concurrently therewith, the shares of such classes are subdivided, consolidated, reclassified or otherwise changed in the same proportion and in the same manner.

Subject to certain exceptions noted below, in the event of an Offer, each outstanding Non-Voting Share shall be redeemed by the Corporation at the Redemption Price per Non-Voting Share at the option of the holder during the Redemption Period and such redemption shall be subject to completion of the Offer. The redemption right may be exercised by notice in writing to the Corporation together with the certificate(s) representing the Non-Voting Shares. The Corporation shall issue a cheque for the aggregate Redemption Price to be paid to such holder (less any tax required to be withheld and paid by such holder) upon completion of the offer (the "**Redemption Date**"). If the Offer is not completed, the Corporation shall return any share certificates representing Non-Voting Shares to the holders thereof.

The redemption right noted above shall not come into effect if: (i) one or more shareholders of the Corporation who did not make or act in concert with the person or persons making the Offer and who, in the aggregate, beneficially own, directly or indirectly, or exercise control or direction over, not less than 50% of the outstanding Common

Shares, determine within five business days after the Offer Date that he or they will continue to so own or exercise control or direction over, in the aggregate, 50% or more of the outstanding Common Shares; (ii) contemporaneously with the Offer, an offer is made to the holders of Non-Voting Shares upon the same terms and conditions as those contained in the Offer, including the consideration to be paid to the holders of Common Shares and the offer is for the same percentage of Non- Voting Shares as the percentage of Common Shares sought to be acquired under the Offer, excluding in each case the number of shares then owned by the offeror; (iii) the board of directors of the Corporation determines within five business days after the Offer Date that the Offer is not bona fide or is made primarily for the purpose of causing the redemption right to come into effect and not primarily for the purpose of acquiring Common Shares; or (iv) the Offer is not completed in accordance with its terms.

From and after a Redemption Date, all Non-Voting Shares which are redeemed in accordance with their terms shall cease to be entitled to dividends and the Non-Voting Shares shall be deemed to be returned to the authorized but unissued capital of the Corporation.

For the purposes of the foregoing:

"**business day**" means a day on which securities may be traded on the floor of the Toronto Stock Exchange or any other stock exchange on which the Common Shares are then listed;

"**Offer**" means an offer to purchase Common Shares (or an acceptance of an offer to sell Common Shares) which must, by reason of applicable securities legislation or by laws, regulations or policies of a stock exchange on which the Common Shares are listed, be made to each holder of Common Shares whose last address on the records of the Corporation is in a province or territory of Canada to which the relevant requirement applies;

"**Offer Date**" means the date on which an Offer is made;

"**Redemption Price**" means the value of the consideration offered under an Offer which, in the case of non cash consideration shall be determined solely by the Board of Directors of the Corporation, acting reasonably; and

"**Redemption Period**" means the period of time commencing on the seventh business day after the Offer Date and terminating on the last date upon which holders of Common Shares may accept the Offer.

Non-Voting Convertible Shares

The holders of Non-Voting Convertible Shares are entitled to receive notice of and to attend at any meeting of the shareholders of the Corporation but are not entitled to vote at any such meeting, except with respect to such matters and in the manner as to which voting rights are accorded to the holders of specified classes of shares pursuant to the provisions of the ABCA.

The holders of the Non-Voting Convertible Shares are entitled to receive dividends if, as and when declared by the board of directors of the Corporation equally, on a share-for-share basis, with the holders of Common Shares.

In the event of liquidation, dissolution or winding-up of the affairs of the Corporation, whether voluntary or involuntary, or in the event of any other distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, or in the event of a reduction or redemption of the capital stock of the Corporation, the holders of the Non-Voting Convertible Shares are entitled to receive an amount per share equal to that amount that is the fair market value of any property received by the Corporation as consideration for the issuance of such Non-Voting Convertible Shares divided by the number of Non-Voting Convertible Shares issued, in lawful money of Canada, the whole before any amount will be paid by the Corporation or any assets of the Corporation will be distributed to holders of Common Shares. After payment to the holders of the Non-Voting Convertible Shares of the amount so payable to them in accordance with the foregoing, they will not be entitled to share in any further distribution of property or assets of the Corporation.

Each holder of Non-Voting Convertible Shares has the right to transfer to any Person all or any of the holder's Non-Voting Convertible Shares, provided (i) the transferee would not be a Control Person (as defined below) of the

Corporation after giving effect to the transfer and (ii) such transfer was made in compliance with all applicable securities laws.

Each holder of Non-Voting Convertible Shares has the right to convert all or any of the holder's Non-Voting Convertible Shares into Common Shares at the Conversion Ratio in the following circumstances:

(i) at any time, provided that the holder would not be a Control Person of the Corporation after giving effect to the conversion; or

(ii) upon a Change of Control Transaction, regardless of whether or not such Change of Control Transaction has been approved by the board of directors of the Corporation.

Each Non-Voting Convertible Share will be deemed to convert into Common Shares at the Conversion Ratio immediately upon the sale, transfer, conveyance or other disposition of such Non-Voting Convertible Share, whether by way of a sale, transfer, conveyance or other disposition that is exempt from the prospectus requirements under applicable securities laws, or a distribution to the public or a secondary offering completed by way of prospectus, provided that the transferee would not be a Control Person of the Corporation after giving effect to the sale, transfer, conveyance or other disposition and the conversion of such Non-Voting Convertible Shares.

The Corporation has the right, following the date that is three years after the issuance date of the Non-Voting Convertible Shares, at its sole option to require that holders of Non-Voting Convertible Shares convert all issued and outstanding Non-Voting Convertible Shares held by them into Common Shares.

For the purposes of the foregoing:

"**Change of Control Transaction**" means any of the following:

(i) an amalgamation, merger, business combination, consolidation, recapitalization, reorganization, liquidation, dissolution or winding-up in respect of the Corporation or any other transaction of the Corporation with another Corporation or entity, other than a wholly-owned subsidiary, or an arrangement pursuant to the *Business Corporations Act* (Alberta) involving the Corporation or another transaction pursuant to which a Person, or group of Persons acting jointly or in concert, acquires all the issued and outstanding Common Shares;

(ii) the direct or indirect sale, lease or other disposition (or any long-term supply arrangement, licence or other arrangement having the same economic effect as a sale) of all or substantially all of the consolidated assets, revenues or earnings, as applicable, or undertaking of the Corporation;

(iii) the direct or indirect acquisition by any Person, or group of Persons acting jointly or in concert, of voting control or direction over an aggregate of 50% or more of the outstanding Common Shares, by take-over bid, issuance of Common Shares or otherwise; or

(iv) any similar transaction or series of transactions involving the Corporation or any of its subsidiaries, directly or indirectly.

"**Control Person**" means (a) a person or company who holds more than 20 per cent of the voting rights attached to all outstanding voting securities of the Corporation, or (b) each person or company in a combination of persons or companies, acting in concert by virtue of an agreement, arrangement, commitment or understanding, which holds more than 20 per cent of the voting rights attached to all outstanding voting securities of the Corporation;

"**Conversion Ratio**" means the number of Common Shares issuable upon conversion of each Non-Voting Convertible Share, which shall initially be one Common Share, subject to adjustment in accordance with the terms of the Non-Voting Convertible Shares;

"**Exchange**" means the Toronto Stock Exchange or, if applicable, such other stock exchange on which the Common Shares are principally traded; and

"**Person**" means an individual, partnership, corporation, trust, unincorporated association, joint venture or other entity and includes a group of Persons acting jointly or in concert.

Preferred Shares

Long Run is authorized to issue an unlimited number of Preferred Shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the board of directors of Long Run prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding up of Long Run, 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.

MARKET FOR SECURITIES

Trading Price and Volume

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

	Common Shares		
	Price Range		
	High ($/share)	Low ($/share)	Volume (000s)
2012			
January	5.84	4.87	2,760
February	5.51	5.02	2,443
March	5.46	4.96	2,275
April	5.38	4.97	2,869
May	5.22	4.21	2,657
June	4.76	3.95	1,652
July	4.97	4.05	1,319
August	4.77	3.79	8,438
September	4.20	3.76	3,805
October(1)	4.50	3.71	3,846
November	4.64	4.10	11,862
December	5.07	4.39	10,913
2013			
January	5.06	4.23	8,926
February	4.52	3.79	5,428
March 1-15	4.74	4.01	3,683

Note:

(1) The WestFire/Guide Arrangement was completed on October 23, 2012 and the WestFire Common Shares traded under the symbol "WFE" prior thereto, as set forth in the table.

Prior Sales

Other than options to acquire Common Shares, no securities of any outstanding class of securities of the Corporation that are not listed or quoted on a market place were issued during the most recently completed financial year of the Corporation. Prior to completion of the WestFire/Guide Arrangement, Guide had outstanding common share purchase warrants which became obligations of the Corporation as the Warrants pursuant to the WestFire/Guide Arrangement. See "General Development of the Business – Guide – 2011".

DIRECTORS AND OFFICERS

The names, province or state and country of residence, positions with the Corporation, and principal occupation of the directors and officers of the Corporation and their age at year-end are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name, Province or State and Country of Residence	Office Held	Principal Occupation	Director Since
William E. Andrew Alberta, Canada Age: 60	Executive Chairman, Chief Executive Officer and Director	Executive Chairman and Chief Executive Officer of the Corporation and Vice Chairman of Penn West Petroleum Ltd.	October 23, 2012
Dale A. Miller Alberta, Canada Age: 52	President and Director	President of the Corporation	October 23, 2012
John A. Brussa(4)(5) Alberta, Canada Age: 55	Director	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	December 13, 2007
Ed Chwyl(2)(3) British Columbia, Canada Age: 69	Director	Lead Independent Director of Baytex Energy Corp. (previously Baytex Energy Ltd.) (Baytex Energy Trust)	December 13, 2007
Paul Dimitriadis(4)(5) Ontario, Canada Age: 42	Director	Chief Operating Officer of Sprott Consulting and Sprott Resource Corp.	October 23, 2012
Jeffery E. Errico (2)(3) Alberta, Canada Age: 62	Director	Chairman of Insignia Energy Ltd.	October 23, 2012
Michael M. Graham(2)(5) Alberta, Canada Age: 53	Lead Director	Independent Businessman, Independent Director of West Valley Energy Corp. and Chairman of Saguaro Resources Ltd.	October 23, 2012
Michael Y. McGovern(1)(3)(4) Texas, U.S.A. Age: 61	Director	Executive Advisor to Cadent Energy Partners LLC (Private Equity)	July 4, 2008
Brad R. Munro(1) (5) Saskatchewan, Canada Age: 53	Director	President and Chief Executive Officer of Bittercreek Capital Corporation, (a private investment and advisory firm)	October 23, 2012
Patricia M. Newson (1) Alberta, Canada Age: 56	Director	Independent Businesswoman since 2012	October 23, 2012

Name, Province or State and Country of Residence	Office Held	Principal Occupation	Director Since
Shivon M. Crabtree[(6)] Alberta, Canada Age: 53	Vice President, Finance and Chief Financial Officer	Vice-President, Finance and Chief Financial Officer of the Corporation	N/A
Corine R. K. Bushfield[(6)] Alberta, Canada Age: 38	Vice President, Finance and Accounting	Vice-President, Finance and Accounting of the Corporation	N/A
Jason W. Fleury Alberta, Canada Age: 42	Vice President, Capital Markets	Vice-President, Capital Markets of the Corporation	N/A
James D. Iverson Alberta, Canada Age: 57	Vice-President, Exploration	Vice-President, Exploration of the Corporation	N/A
Dale J. Orton Alberta, Canada Age: 40	Vice-President, Engineering and Operations	Vice-President, Engineering and Operations of the Corporation	N/A
Devin K. Sundstrom Alberta, Canada Age: 40	Vice-President, Production	Vice-President, Production of the Corporation	N/A
V. William Tang Kong Alberta, Canada Age: 52	Vice-President, Corporate Development	Vice-President, Corporate Development of the Corporation	N/A
C. Steven Cohen Alberta, Canada Age: 57	Secretary	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	N/A

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Health, Safety and Environment Committee
(4) Member of the Human Resources Committee.
(5) Member of the Corporate Governance Committee.
(6) Ms. Crabtree is retiring from Long Run in March, 2013, and, upon her retirement, Ms. Bushfield will also assume the responsibilities of Chief Financial Officer.
(7) Long Run does not have an executive committee of its board of directors.

All of the above directors have held their principal occupations or other positions with the same organization as listed above for at least the last five years except as described below and as described under "Management" and "Audit Committee Information – Composition of the Audit Committee", and, other than the following. Mr. Chwyl has been the Lead Independent Director of Baytex Energy Corp. since February 17, 2009, and prior thereto was Chairman of the board of directors of Baytex Energy Ltd. since 2003. Mr. Graham served as an Executive Vice President of EnCana Corp. since April 14, 2005 and served as President of its Canadian Division until February 2012.

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

As at March 15, 2013, the directors and executive officers of Long Run, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 2,493,515 Common Shares or approximately 2.3% of the issued and outstanding Common Shares and 920,000 Warrants or approximately 40% of the issued and outstanding Warrants.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

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

Bankruptcies

To Long Run's knowledge, other than as disclosed herein, no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation: (a) is, as at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any issuer (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr. McGovern was a director of Tronox, Inc. ("**Tronox**"). Tronox filed for bankruptcy on January 12, 2009 and its reorganization was consummated on February 14, 2011.

Mr. Munro was a director of Kipp & Zonen Inc. ("**Kipp & Zonen**"), as part of his employment with GrowthWorks Canadian Fund Inc. ("**Growthworks**") from December 1996 to April 19, 2004. GrowthWorks held a convertible debenture in the principal amount of $2,000,000 which was originally funded in December 1996 with a maturity in March 2001. On March 25, 2004, Kipp & Zonen was served with Notice of Petition for Receiving Order by its landlord for unpaid rent. GrowthWorks served notice to Kipp & Zonen on April 7, 2004 with a Notice of Intention to Enforce Security under the *Bankruptcy and Insolvency Act* (Canada) under the terms of its amended and restated convertible debenture dated March 31, 2002. On April 21, 2004, GrowthWorks obtained an order of the Saskatchewan Court of Queen's Bench appointing Ernst & Young Inc. receiver of all of the undertaking, property and assets of the company. Effective April 19, 2004, Mr. Munro and the other directors and officers of Kipp & Zonen resigned.

Mr. Munro is a director of Winalta Inc. Winalta Inc. and each of its subsidiaries, (collectively "Winalta") obtained creditor protection under the Companies' Creditors Arrangement Act (Canada) (the "**CCAA**") pursuant to an order granted on April 26, 2010 by the Court of Queen's Bench of Alberta (the "**Court**"). Deloitte & Touche Inc. was appointed as Winalta's monitor. The CCAA filing follows the receipt on March 31, 2010 by Winalta and its subsidiaries of demands for payment and Notices of Intention to Enforce Security from Winalta's principal lender, HSBC Bank of Canada. On October 22, 2010, Winalta received Court and creditor approval of a plan of arrangement (the "Plan") pursuant to the CCAA under which it amalgamated with certain of its subsidiaries and, effective October 29, 2010, emerged from CCAA protection to begin focused operations on its oilfield services business. The board of directors maintained its usual role during the period while Winalta was under CCAA protection and, together with management, was primarily responsible for formulating the Plan for restructuring Winalta's affairs.

Penalties or Sanctions

To Long Run's knowledge, other than as disclosed herein, no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has been subject to (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

MANAGEMENT

William E. Andrew, Executive Chairman, Chief Executive Officer and Director

Mr. Andrew has 35 years of oil and natural gas industry experience. He has acted as the Senior Executive Officer of Penn West Exploration Ltd. from December 1992 until his appointment as Vice-Chairman on August 9, 2011. During this time, he led the company from a small capital explorer to one of Canada’s largest senior oil and natural gas exploration and production companies. Mr. Andrew joined Guide as Executive Chairman on August 11, 2011 and was also appointed Chief Executive Officer on November 15, 2011. On completion of the WestFire/Guide Arrangement, he was appointed Chairman and Chief Executive Officer of Long Run. Mr. Andrew received an engineering diploma from the University of Prince Edward Island in 1973 and a Bachelor of Engineering in Mining from the Technical University of Nova Scotia in 1975. Mr. Andrew is currently serving his second term as Chancellor of the University of Prince Edward Island, Director of The Fathers of Confederation Buildings Trust, Board of Management member of the Alberta Economic Development Authority and honorary co-chair of L.M. Montgomery Land Trust fundraising campaign. He has served as a Trustee of the Grace Hospital as well as on the Board of Governors of the Canadian Association of Petroleum Producers, and is a former Director of the Canadian Wind Institute.

Dale A. Miller, President and Director

Mr. Miller has 30 years of oil and natural gas industry experience. Mr. Miller joined Guide on August 11, 2011 as President and was appointed President of Long Run on completion of the WestFire/Guide Arrangement. Prior thereto he has most recently acted as Vice-President and Chief Operating Officer of an intermediate oil and gas company Pace Oil and Gas Ltd. From 1993 to 2003, Mr. Miller worked for Penn West Exploration Ltd. in positions of increasing responsibility including for four years as the Vice President Operations and Engineering reporting to Mr. Andrew.

Mr. Miller received a Petroleum Engineering degree from the University of Tulsa.

Shivon M. Crabtree, Vice President, Finance and Chief Financial Officer

Ms. Crabtree has been involved in the oil and natural gas business for the past 32 years. Ms. Crabtree joined Guide as Vice President, Finance and Chief Financial Officer on its inception in March 2003 and Long Run on completion of the WestFire/Guide Arrangement. Ms. Crabtree was Vice President, Finance of Culane Energy Corp. from December 2002 to August 2007. Prior thereto, Ms. Crabtree was the Vice-President, Finance and Chief Financial Officer of High Point Resources Inc. from December 2001 to March 2004. She was Vice-President Finance and Chief Financial Officer of Venture Energy Inc. from December 2002 to January 2005. Ms. Crabtree was the Vice-President Finance and Chief Financial Officer at Magin Energy Inc. during the period 1996 to 2001.

Ms. Crabtree holds a Bachelor of Business Administration from the University of Regina and the Certified Management Accountant (CMA) designation.

Ms. Crabtree is retiring from Long Run in March, 2013.

Corine R. K. Bushfield, Vice President, Finance and Accounting

Ms. Bushfield is a Chartered Accountant with 17 years' experience in the oil and natural gas industry. Prior to joining Long Run in March 2013, Ms. Bushfield worked for EnCana Corporation for 13 years in positions of increasing responsibility within corporate finance, most recently as Vice President and Assistant Controller.

Ms. Bushfield holds a Bachelor of Commerce degree from the University of Calgary and a designation as a Chartered Accountant from the Institute of Chartered Accountants of Alberta.

Ms. Bushfield will also assume the responsibilities of Chief Financial Officer upon Ms. Crabtree's retirement.

James D. Iverson, Vice President, Exploration

Mr. Iverson is a professional geologist with 31 years of diversified industry experience in Western Canada. Mr. Iverson has a proven track record of discovering oil and gas pools mainly in the Peace River Arch and Central Alberta areas. He has held position of increasing responsibility at Baytex Energy Ltd., Hadrian Energy Corp., Wascana Energy Inc., Alberta Energy Oil and Gas Company Ltd., and Chieftain Development Company Ltd. Mr. Iverson joined Guide in September 2003 and Long Run on completion of the WestFire/Guide Arrangement.

Mr. Iverson holds a Bachelor of Science degree with Honors in Geology from the University of Alberta and is registered as a Professional Geologist in Alberta.

Dale J. Orton, Vice President, Engineering and Operations

Mr. Orton is a professional engineer with 19 years of exploitation, production, operations, business development and acquisition experience. Mr. Orton joined Guide in June 2005 and Long Run on completion of the WestFire/Guide Arrangement. Prior to joining Guide, he held positions of increasing responsibility with Flowing Energy Corporation, KeyWest Energy Corporation, Velvet Exploration Ltd. and Renaissance Energy Ltd.

Mr. Orton holds a Bachelor of Engineering degree from the University of Victoria and is a Registered Professional Engineer in Alberta and in Saskatchewan.

Devin K. Sundstrom, Vice President, Production

Mr. Sundstrom is a professional engineer with 19 years of drilling and completion, exploitation, production operations and acquisition experience. Mr. Sundstrom joined Guide in August 2004 and Long Run on completion of the WestFire/Guide Arrangement. Prior to joining Guide, he has held positions with increasing responsibility at Hunt Oil Company, Renaissance Energy Ltd. and Northstar Energy Corporation.

Mr. Sundstrom holds a Bachelor of Science Degree in Chemical Engineering from the University of Calgary and is a Registered Professional Engineer in Alberta.

V. William Tang Kong, Vice President, Corporate Development

Mr. Tang Kong has 25 years of oil and natural gas industry experience. From 1995 to 2008, Mr. Tang Kong worked for Penn West Exploration Ltd. in positions of increasing responsibility including Senior Vice President Corporate Development reporting to Mr. Andrew. Mr. Tang Kong joined Guide in August 2011 and Long Run on completion of the WestFire/Guide Arrangement.

Mr. Tang Kong received a Bachelor of Science degree in Mechanical Engineering in 1981, a Bachelor of Science degree in Geology in 1984, and a Master of Science degree in Petroleum Geology in 1988, all from the University of Calgary.

Jason W. Fleury, Vice President, Capital Markets

Mr. Fleury has more than a decade of oil and natural gas industry experience, most recently as Senior Manager, Investor Relations of a senior independent oil gas company, Penn West Petroleum Ltd. Prior to this, Mr. Fleury held various positions of increasing responsibility in the Investor Relations field at other oil and natural gas companies in western Canada. Mr. Fleury joined Guide in September 2012 and Long Run on completion of the WestFire/Guide Arrangement.

Mr. Fleury holds a Masters of Business Administration from the University of Calgary and a Bachelor of Arts from the University of Regina.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

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

Composition of the Audit Committee

The members of the Audit Committee are Patricia M. Newson, Michael Y. McGovern and Brad R. Munro. The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate. The following is a description of the education and experience of each member of the Audit Committee.

Patricia M. Newson, Chairman

Ms. Newson was appointed a director of the Corporation on October 23, 2012 . Ms. Newson is the chairman of the board of Heritage Gas Ltd., and serves on the boards of Brookfield Residential Properties Inc., the Alberta Electric System Operator, and Quality Urban Energy Systems of Tomorrow (QUEST) Canada, and is a member of the Alberta Securities Commission's Financial Advisory Committee. Ms. Newson was a director and audit committee member of Guide from 2011 to 2012, Brookfield Asset Management Inc. from 2008 to 2010, and the Canadian Gas Association from 2006 to 2011 and a director of AltaGas Utility Group from 2005 to 2009. From 2005 through 2009 she was the President and Chief Executive Officer of AltaGas Utility Group Inc., a natural gas distribution holding company listed on the TSX. Ms. Newson retired in 2011 from AltaGas Ltd. as the President of AltaGas Utility Group Inc. Ms. Newson originally joined AltaGas Income Trust in 1996 and was Senior Vice President, Finance and Chief Financial Officer until 2006 and Senior Vice President through 2008. Prior to joining AltaGas Income Trust, her experience included consulting for utility companies and crown corporations; and positions in financial reporting and merger and acquisition functions with private equity firms and with Olympia and York Enterprises, GW Utilities and Gulf Canada. Ms. Newson holds a Bachelor of Commerce degree (with distinction) in accounting, is a member of the Institute of Chartered Accountants of Alberta, and is an Institute Certified Director (ICD.D).

Michael Y. McGovern

Mr. McGovern has been Executive Advisor to Cadent Energy Partners LLC since January 2008 and prior thereto was President and Chief Executive Officer of Pioneer Companies Inc. from 2002 to 2007. Mr. McGovern holds a bachelor of science in business from Centenary College and attended the graduate business school at Tulane University, has been the Chief Executive Officer and/or Chairman of seven public companies, a director of a number of public and private companies and previously served on the Audit Committees of WestFire and Tronox, Inc.

Brad R. Munro

Mr. Munro is the President and Chief Executive Officer of Bittercreek Capital Corporation, a private investment and advisory firm. Through Bittercreek Capital Corporation, Mr. Munro was a contractor to GrowthWorks Capital WV Ltd. and its affiliates in the role of Vice President, Investments from May 2006 to August 2009. Prior thereto, Mr.

Munro was an employee of GrowthWorks Capital Ltd. and its affiliates since September 1991. Mr. Munro holds a Bachelor of Commerce degree from the University of Saskatchewan and has extensive experience in corporate finance and investment in the oil and gas and other industries. Mr. Munro has held various senior positions requiring regular review of financial statements and has served as an Audit Committee member, including Chairman, for a number of publicly traded companies. Mr. Munro presently serves as a director of Winalta, Inc., and Secure Energy Services Inc.

Pre-Approval of Non-Audit Services

Long Run has adopted policies and procedures with respect to the pre-approval of non-audit services to be provided by the Corporation's external auditors. The Audit Committee approves a schedule which summarized the services to be provided that the Audit Committee believes to be typical, recurring or otherwise likely to be provided. 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. Non-audit services that arise that were not contemplated in the schedule may be pre-approved by the chair of the Audit Committee in respect of fees not in excess of $25,000 between meetings of the Audit Committee and the full Audit Committee is informed of the services at its next meeting.

External Auditor Service Fees

PricewaterhouseCooperers LLP were the Corporation's auditors prior to the annual and special meeting of shareholders held on October 22, 2012 called to approve, among other things, the WestFire/Guide Arrangement and at which meeting Ernst & Young LLP were appointed as auditors of the Corporation. The following table summarizes the fees paid by the Corporation to Ernst & Young LLP since their appointment as auditors of the Corporation, as well as the fees paid by WestFire to PricewaterhouseCoopers LLP prior thereto.

Auditor	Year	Audit Fees	Audit – Related Fees(1)	Tax Fees(2)	All Other Fees(3)
		($)	($)	($)	($)
Ernst & Young LLP					
	2012	306,750	10,000	59,000	Nil
	2011	Nil	Nil	Nil	Nil
PricewaterhouseCoopers LLP	2012	39,000	189,459	10,925	Nil
	2011	134,000	58,000	5,500	Nil

Notes:

(1) Represents the aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of all of the Corporation's financial statements (and not reported under the heading "Audit Fees"). The services comprising the fees disclosed under this category consisted of the conduct of due diligence procedures in connection with financings and acquisitions.

(2) Represents the aggregate fees billed for professional services for tax compliance, tax advice and tax planning. The services comprising the fees disclosed under this category consisted of tax consultations and tax compliance services.

(3) Represents the aggregate fees billed for products and services not included under the headings "Audit Fees", "Audit Related Fees" and "Tax Fees".

CONFLICTS OF INTEREST

The directors or officers of the Corporation may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, 1000, 444 – 2nd Avenue S.W., Calgary, Alberta, T2P 5E9.

Valiant Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar of the Common Shares. Valiant Trust Company also acts as the transfer agent and registrar of the Non-Voting Convertible Shares.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

During the year ended December 31, 2012, 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 with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described herein, there were no material interests, direct or indirect, of directors or executive officers of the Corporation, of any shareholder who beneficially owns or controls or directs, directly or indirectly, more than 10% of any class of outstanding voting securities of the Corporation, or any other Informed Person (as defined in National Instrument 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Corporation or any of its subsidiaries.

On September 16, 2011, Guide issued an aggregate of 2,300,000 Units at a price of $2.81 per Unit. Each Unit was comprised of one Class A Share of Guide and one share purchase warrant, (each of which require one Class A Share of Guide at an exercise price of $3.10 for a period of three years from the date of issuance and any time after the Class A Shares have achieved a 20-day volume weighted average trading price exceeding $5.00 per share), and which share purchase warrants were assumed by Long Run as the Warrants pursuant to the WestFire/Guide Arrangement. The following directors and executive officers of the Corporation, who were also directors and/or executive officers of Guide, acquired an aggregate of 860,000 Units: William E. Andrew, Executive Chairman and Chief Executive Officer (205,000 Units); Dale A. Miller, President (175,000 Units); V. William Tang Kong, Vice President, Corporate Development (200,000 Units); John A. Brussa, Director (200,000); Dale J. Orton, Vice President, Operations and Engineering (30,000); Devin K. Sundstrom, Vice President, Production (15,000 Units); Shivon M. Crabtree, Vice President, Finance and Chief Financial Officer (15,000); and James D. Iverson, Vice President, Exploration (15,000).

In connection with the Orion Acquisition, Sprott Resources Corp. ("**SRC**") exchanged its 229,334,351 common shares of Orion (approximately 71% of the outstanding common shares of Orion on a fully diluted basis) for Common Shares of WestFire and Non-Voting Convertible Shares of WestFire on the same basis as available to other shareholders of Orion. SRC also entered into the Investor Agreement with WestFire (see "Material Contracts").

Pursuant to the WestFire/Guide Arrangement, each outstanding common share of Guide was transferred to WestFire in exchange for 0.4167 of a common share of WestFire (being the Common Shares of Long Run), and Guide and WestFire were amalgamated and continued under the name Long Run Exploration Ltd. As a result of the

WestFire/Guide Arrangement, the outstanding Guide Warrants were assumed by Long Run and the Warrants entitle a holder to acquire Common Shares of Long Run. Management of Guide assumed management of Long Run and the board of directors of Long Run was reconstituted as disclosed herein (see "Directors and Officers" and "Management"). As a result, the WestFire executive officers, being Lowell E. Jackson, Frank P. Muller, Jeff Holmgren, Darrin R. Drall, Christopher J. Bennett and Cam King, received severance (being amounts paid in lieu of salary, benefits and bonus) in the amounts of $992,200, $582,600, $556,950, $582,600, $582,600 and $545,100, respectively, and other bonus payments in the amount of $532,574, $439,825, $200,908, $439,825, $240,825 and $240,825, respectively, certain of which were triggered upon the change of control resulting from the WestFire/Guide Arrangement and certain of which were payable in any event. See also "The Arrangement – Interest of Certain Persons and Companies in the Arrangement", in the Joint Information Circular of Guide and WestFire dated September 24, 2012, which section (other than cross references therein to other sections of the Joint Information Circular) is incorporated herein by reference. The Joint Information Circular is available under the Corporation's profile on SEDAR at www.sedar.com.

Certain directors and officers of Long Run have participated in private placements and public offerings by Long Run (or its predecessors) on the same basis as other arm's length subscribers to such offerings.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation has not entered into any material contracts within the most recently completed financial year or before Long Run's most recently completed financial year which are still in effect other than:

1. an investor agreement dated as of May 11, 2011, (the "**Investor Agreement**") entered into by WestFire (now Long Run) and Sprott Resources Corp. ("**SRC**") in connection with the Orion Arrangement. Pursuant to the Investor Agreement, SRC agreed that, without the prior written consent of WestFire, it will not sell its Non-Voting Convertible Shares, in a single transaction or series of related transactions, to one or more purchasers, unless the aggregate gross proceeds due to SRC as a result of such transaction(s) exceed CDN$10,000,000. The Investor Agreement also contained restrictions on the disposition of the Common Shares acquired by SRC pursuant to the Orion Arrangement, but such restrictions have expired.

   The Investor Agreement also provides:

   (a) certain "drag-along" rights whereby SRC agreed in the event of a bona fide offer from an arm's length party to purchase or otherwise acquire (including, without limitation, by way of take-over bid, plan of arrangements or amalgamation) 90% or more of the aggregate outstanding Common Shares at a price in excess of $7.90 per Common Share (a "**Change of Control Transaction**"), upon notice by WestFire that the board of directors intends to support the Change of Control Transaction and enter into a binding agreement in respect of the transaction, SRC is required to sell or otherwise transfer its Common Shares (including any Common Shares acquired after the conversion of the Non-Voting Convertible Shares) upon the same terms and conditions as the Change of Control Transaction;

   (b) if WestFire receives a bona fide offer for 90% or more of the outstanding Common Shares at a price equal to or in excess of $7.90 per Common Share, and in the event that the proposed transaction is proceeding pursuant to a statutory plan of arrangement or other transaction to be approved by special resolution of the holders of the Common Shares, SRC will not object to grouping of the Non-Voting Convertible Shares and the Common Shares to be voted as a single class in connection with the resolution approving the proposed transaction.

   (c) WestFire's agreement to provide SRC with certain information as required by SRC to comply with its reporting obligations under applicable law; and

   (d) SRC with a "demand registration" right until three months after it ceases to be the beneficial owner of more than 10% of the outstanding Common Shares.

2. the arrangement agreement made as of August 8, 2012, between Guide and WestFire entered into in connection with the WestFire/Guide Arrangement.

3. the asset purchase and sale agreement made as of November 15, 2012, pursuant to which Long Run disposed of properties in the Plato area of West Central Saskatchewan, as described under "General Development of the Business – Three-Year History – Long Run".

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 Sproule, the Corporation's independent engineering evaluators and Ernst & Young LLP, the Corporation's auditors and Pricewaterhouse Coopers LLP, WestFire's auditors prior to completion of the WestFire/Guide Arrangement. None of Sproule or 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 Sproule have or are to receive any registered or beneficial interest, direct or indirect, in any of Long Run's securities or other property of Long Run or of Long Run's associates or affiliates, either at the time Sproule prepared the report, valuation, statement or opinion or any time thereafter. Ernst & Young LLP, Chartered Accountants, the Corporation's auditors, and Pricewaterhouse Coopers LLP, WestFire's auditors prior to completion of the WestFire/Guide Arrangement, 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.

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand primarily determines oil prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the availability of transportation, 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. The NEB is currently undergoing a consultation process to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act*, which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX) or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can be set by such supply and demand. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

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

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

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

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

Alberta

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

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

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

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

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

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

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

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

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

On March 17, 2011, the Government of Alberta approved the *New Well Royalty Regulation* providing for the permanent implementation of a formerly temporary royalty program which provides for a maximum 5% royalty rate for eligible new wells for the first 12 productive months or until the regulated "volume cap" is reached.

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

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

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

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

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

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

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 or through an Enhanced Oil Recovery ("**EOR**") Scheme ("**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. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

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. It is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to oil production on Crown land. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, 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. The freehold production tax rate for natural gas liquids is a flat 12.25%.

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

- *Summer Royalty Credit Program* providing a royalty credit equal to 10% of the goods and services costs up to $100,000 for wells drilled between April 1 and November 30 of each year;

- *Deep Royalty Credit Program* providing a royalty credit defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres (or 1,900 metres if spud after August 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs that relate to locations specific factors;

- *Deep Re-Entry Royalty Credit Program* providing royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date subsequent to December 1, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres 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;

- *Natural Gas Royalty Reduction* providing a reduced royalty on wells drilled on land rights acquired after June 1, 1998 and completed within five years of the date the rights are issued;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 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 monthly royalty reductions for low productivity non-conservation natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow non-conservation natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.0 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

- *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 that is located on either Crown or freehold land and completed in a new pool discovered 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 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

In August 2012, the Government of British Columbia announced that it is bringing in a nominal 2% royalty on both oil and natural gas on the revenue for the first year of production for wells drilled from September 2012 through to June 2013.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "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 incremental oil from new or expanded waterflood projects) or new oil (oil from wells drilled on or after January 1, 1994). 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. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and 250 m^3 per month for "fourth tier oil". Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

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

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations, 2012* which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.** The current regulatory scheme provides for **c**ertain differences with respect to the administration of "forth tier gas" which is associated gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

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

- *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% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and

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

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

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

Land Tenure

The respective provincial governments predominantly own crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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

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

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements for the satisfactory abandonment and reclamation of well and facility sites. 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.

On a Federal level and pursuant the *Prosperity Act*, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

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

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP"**) which came into effect on September 1, 2012. The LARP covers approximately 93,212 square kilometres and is in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the provinces oilsands resource and much of the Cold Lake oilsands area. LARP establishes six new conservation areas, bringing the total conserved land in the region to two million hectares, or 22%—an area three times the size of Banff National Park. The Alberta government plans to pay $30 million to producers whose leases will be cancelled in areas set aside for conservation. Oil and gas companies will be allowed to continue to operate in conservation and recreation areas while oilsands companies' tenures will be cancelled. New petroleum and gas tenure sold in conservation areas will include a restriction that prohibits surface access. Application procedures for activities and facilities in the LARP, regulated by the Energy Resources Conservation Board and the Alberta Utilities Commission, respectively, have been changed to accommodate the new restrictions set out in the LARP. The LARP is the first of seven regions to get a land use plan. The next will be the South Saskatchewan region.

In British Columbia, the *Oil and Gas Activities Act* (the "**OGCA**") impacts conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities in British Columbia. Under the OGCA, the British Columbia Oil and Gas Commission has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGCA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act* requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, and permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole, and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

In May of 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Climate Change Regulation

Federal

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 green house gases ("**GHGs**") and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, which will be applied to regulated sectors on a facility-specific, sector-wide or a company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although the intention was for draft regulations for the implementation of the Updated Action Plan to become binding on January 1, 2010, the only regulations announced pertain to carbon dioxide emissions from coal-fired generation of electricity (finalized in summer 2012). Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent implementation of the proposals contained in the Updated Action Plan will occur.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it would issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline. However, in March 2012, the EPA proposed a strict GHG standard on new power plants only. While it is expected that this rule could encourage building new natural gas power plants rather than coal plants, the actual effect of the new rule will not be able to be quantified for some time.

Alberta

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

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

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

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

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 current tax level is $30 per tonne of CO_2 equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. 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.

In their 2012 Budget, British Columbia announced the government will undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review will cover all aspects of the carbon tax, including revenue neutrality, and will consider the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. Under this comprehensive review, British Columbians can make written submissions to British Columbia's Minister of Finance, and these will be considered as part of the 2013 Budget process.

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 partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. 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 GHG emissions.

The Cap and Trade Act sets out the requirements for the reporting of the greenhouse gas emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under further development.

Saskatchewan

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

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. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. 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. Deliverability uncertainties related to the distance the Corporation's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A 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 because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

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, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and on its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and 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, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively 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, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Corporation could incur significant costs.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. The price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

Hedging

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

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

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

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

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

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continue to affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

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

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.

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 in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- 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.

The estimation 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. Such variations could be material.

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

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

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by OPEC and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected.

Because of the global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

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

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility which could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

Issuance of Debt

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

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See: "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Hydraulic Fracturing

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Compliance with environmental 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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so 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, may 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. 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 depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

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

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

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

Competition

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

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and which may require the Corporation to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas ("**GHG**") emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Although it is not the case today, some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. 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.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Recently, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively affect the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly affect 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, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares of the Corporation.

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. The actual interest of the Corporation in properties may, therefore, vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Insurance

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

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

Dividends

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

Aboriginal Claims

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

Seasonality

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

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 affect 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 or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under 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.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be materially adversely affected. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil and other liquid hydrocarbons. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new or modify the royalty regime which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of this Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the

Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

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

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "Forward-Looking Statements" of this Annual Information Form.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of security holders that involved the election of directors. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

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

Management of Long Run Exploration Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

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

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

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

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

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

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

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

(b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

DATED as of this 18th day of March, 2013.

(signed) William E. Andrew
Executive Chairman and Chief Executive Officer

(signed) Dale J. Orton
Vice-President, Engineering and Operations

(signed) Michael M. Graham
Lead Director and Chair of the Reserves Committee

(signed) Jeffery E. Errico
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 Long Run Exploration Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, 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.

3. 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).

4. 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.

5. 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, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

			Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
Independent Qualified Reserves Evaluator or Auditor	Description & Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
			M$	M$	M$	M$
Sproule	Evaluation of the P&NG Reserves of Long Run Exploration Ltd., as of December 31, 2012 prepared September 2012 to March 2013	Canada	8,312	1,110,795	-	1,119,107

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

7. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

EXECUTED as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta, dated March 6, 2013.

(signed) Attila A. Szabo, P.Eng.
Manager, Engineering and Partner

(signed) Steven J. Golko, P.Eng
Petroleum Engineer and Partner

(signed) Matthew J. Tymchuk, P.Eng.
Petroleum Engineer and Associate

(signed) Alec Kovaltchouk, P.Geo.
Manager, Geoscience and Partner

(signed) Cameron P. Six, P.Eng.
Vice-President, Engineering, Canada and Director

SCHEDULE "C"

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Role and Objective

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

The primary objectives of the Committee are as follows:

1. to assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Long Run and related matters;
2. to provide better communication between directors and external auditors;
3. to enhance the external auditor's independence;
4. to increase the credibility and objectivity of financial reports; and
5. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Long Run or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 — Audit Committees ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.
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 NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.
2. Recommending to the Board the nomination and compensation of the external auditors.
3. Satisfy itself on behalf of the Board with respect to Long Run's internal control systems.

4. Review the annual and interim financial statements of Long Run 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.

5. 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 Long Run's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

6. 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 Long Run 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.

7. Review with external auditors (and internal auditor if one is appointed by Long Run) their assessment of the internal controls of Long Run, 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 Long Run and its subsidiaries.

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

9. Establish a procedure for:

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

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

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

11. To review Long Run's disclosure controls and procedures to ensure such disclosure controls and procedures provide reasonable assurance that:

    - Long Run's Disclosure Policy is effectively implemented across all business units and corporate functions; and

    - information of a material nature is accumulated and communicated to senior management, including the Chief Executive Officer, President and the Vice President, Finance and Chief Financial Officer, to allow timely decisions on required disclosures and certification.

12. To review the results of Long Run's annual evaluation of the effectiveness of Long Run's disclosure controls and procedures.

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 Long Run. All employees of Long Run are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Long Run 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 will attend meetings of the Committee where matters relating to the functions as the Audit Committee are dealt with, 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 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.