CHINOOK
energy inc

ANNUAL INFORMATION FORM

for the year ended December 31, 2014

March 12, 2015

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ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbl	thousand barrels
MMbbl	million barrels
Bbls/d	barrels per day
NGLs	natural gas liquids

Natural Gas

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

Other

API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or boe	barrel of oil equivalent on the basis of 6 Mcf/1 BOE for natural gas and 1 Bbl/1 BOE for crude oil and natural gas liquids (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
Brent	a blended crude stream produced in the North Sea region which serves as a reference or "marker" for pricing a number of other crude streams
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
MMBOE	1,000,000 barrels of oil equivalent
McfE	thousand cubic feet of gas equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
MM$	millions of dollars

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

CONVERSIONS

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

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	Hectares	0.405
Hectares	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);

"**Adam Concession**" means the Adam production concession that covered 212,510 gross acres in Tunisia in which Chinook indirectly owned a 5% non-operated interest, which concession was disposed of pursuant to the Tunisian Disposition;

"**AIMCo**" means Alberta Investment Management Corporation, an Alberta crown corporation which is responsible for managing and investing funds on behalf of certain Alberta public pension plans, endowments and government funds;

"BBT Concession" or "**Bir Ben Tartar Concession**" means the Bir Ben Tartar production concession that covered 86,981 gross acres in Tunisia in which Chinook indirectly owned an 86% operated interest, which concession was disposed of pursuant to the Tunisian Disposition;

"**Chinook**" or the "**Corporation**" means Chinook Energy Inc. and includes its predecessors where the context so requires and, unless the context otherwise requires, includes the Corporation's subsidiaries;

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

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

"**Credit Facility**" means the Corporation's $125 million revolving term credit facility with a syndicate of financial institutions to provide for a $110 million syndicated credit facility and a $15 million operating facility, which facility is secured by the Corporation's consolidated assets in Canada;

"**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;

"**HMQ**" means Her Majesty the Queen in Right of the Province of Alberta;

"**Iteration**" means Iteration Energy Ltd., a predecessor corporation to Chinook which was amalgamated under and governed by the ABCA;

"**Iteration Acquisition**" means SVI's acquisition on June 29, 2010 of all of the outstanding securities of Iteration and subsequent amalgamation with Iteration to form Chinook Energy Inc. completed pursuant to a plan of arrangement under the ABCA;

"**McDaniel**" means McDaniel & Associates Consultants Ltd., independent petroleum consultants, Calgary, Alberta;

"**McDaniel Report**" means the report of McDaniel dated February 9, 2015 evaluating all of Chinook's Canadian crude oil, natural gas liquids and natural gas reserves as at December 31, 2014, in accordance with the standards contained in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in NI 51-101 and the COGE Handbook;

"**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 royalties obligations, plus the Corporation's royalty interest 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* adopted by the Canadian Securities Administrators;

"**Person**" includes an individual, a body corporate, a trust, a union, a pension fund, a government and a governmental agency;

"**Shareholders**" means the holders of Common Shares from time to time;

"**subsidiary**" means, in relation to any Person, any body corporate, partnership, joint venture, association or other entity of which more than 50% of the total voting power of shares or units of ownership or beneficial interest entitled to vote in the election of directors (or members of a comparable governing body) is owned or controlled, directly or indirectly, by such Person;

"**SVI**" means Storm Ventures International Inc., a predecessor corporation to Chinook which was incorporated under and governed by the ABCA;

"**SVI Barbados**" means Storm Ventures International (Barbados) Limited, a former indirect wholly-owned subsidiary of the Corporation;

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

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

"**Tunisian Disposition**" means the disposition by the Corporation's wholly-owned subsidiary, Storm Ventures International (BVI) Limited, completed on August 19, 2014 and effective January 1, 2014, of all of the issued and outstanding shares of SVI Barbados, which directly and indirectly owned all of the Corporation's Tunisian assets for gross proceeds of approximately US$128.5 million (including positive working capital of approximately US$14.5 million); and

"**US$**" means United States dollars.

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, 2014.

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

READER ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, budgeted amounts in fiscal 2015 and the expectation that such amounts will be spent in the manner, location and timeframes set forth herein, expectations of drilling plans in 2015, future exploration and development activities and the timing thereof, financial and business prospects and financial outlook, reserve and production estimates and the effect of government announcements, proposals and legislation, may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "estimate", "expect", "forecast", "intend", "outlook", "plan", "potential", "project", "continue", "target" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and natural 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, ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of the Corporation'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 the Corporation 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 the Corporation 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 Annual Information Form, assumptions have been made regarding, among other things: future oil and natural gas prices; future currency exchange and interest rates; the impact of increasing competition; that the Corporation will continue to conduct its operations in a manner consistent with past operations; the timely receipt of required regulatory approvals; the ability of the Corporation 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 the Corporation has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Corporation 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 or exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; certain cost assumptions, the results of negotiations and the plans of the Corporation's partners in certain of its areas; and that the budgeted amounts and expenditures set forth herein, which are subject to the discretion of the Board of Directors of the Corporation, will not be amended in the future; and the ability of the Corporation to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. 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 natural 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.

CORPORATE STRUCTURE

Name, Address and Incorporation

The Corporation was incorporated under the name "Storm Ventures International Inc." ("**SVI**") pursuant to the ABCA on August 28, 2003. On June 29, 2010, the Corporation was amalgamated with Iteration Energy Ltd. to form "Chinook Energy Inc." pursuant to the Iteration Acquisition. On January 1, 2014, the Corporation was amalgamated with two of its wholly-owned subsidiaries, Chinook Energy Ltd. and Iteration Energy Inc., to form "Chinook Energy Inc.". On January 1, 2015, the Corporation was amalgamated with its wholly-owned subsidiary, 1398216 Alberta Ltd., to form "Chinook Energy Inc.".

The Corporation's head office is located at Suite 1000, 517 – 10th Avenue S.W., Calgary, Alberta, T2R 0A8 and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

Individually the Corporation's subsidiaries accounted for (i) less than 10% of the Corporation's consolidated assets as at December 31, 2014, and (ii) less than 10% of the Corporation's consolidated revenues for the year ended December 31, 2014. In the aggregate, the subsidiaries accounted for less than 20% of each of (i) and (ii) describe in the preceding sentence.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The following is a summary of the significant events in the development of Chinook's business over the last three completed financial years.

Year Ended December 31, 2012

During 2012, Storm Ventures International (Barbados) Limited ("**SVI Barbados**") accelerated development of the Bir Ben Tartar Concession in Tunisia.

During 2012, in response to continued soft North American natural gas prices, the Corporation focused its Canadian operations on oil and liquids-rich drilling opportunities in the Grande Prairie and Peace River Arch areas of Alberta along with continued non-strategic property dispositions. During the year ended December 31, 2012, the Corporation completed a number of non-core asset dispositions from its Canadian asset base for aggregate net proceeds of approximately $106.3 million.

In December 2012, the Corporation acquired, effective April 1, 2012, certain assets in the greater Grande Prairie area of northwestern Alberta from a senior producer for $31 million, before closing adjustments and related costs. The acquired assets are within the Corporation's core Grande Prairie operating area and expanded the Corporation's Dunvegan and Doe Creek oil focus.

On December 11, 2012, the Corporation entered into the Credit Facility with a syndicate of financial institutions to provide for a $115 million revolving term credit facility that consisted of a $100 million syndicated credit facility and a $15 million operating facility. The Credit Facility replaced the Corporation's then existing syndicated credit facility.

Year Ended December 31, 2013

During 2013, in response to continued soft North American natural gas prices, the Corporation focused its Canadian operations on oil and liquids-rich drilling opportunities in the Grande Prairie and Peace River Arch areas of Alberta along with continued non-strategic property dispositions. During the year ended December 31, 2013, the Corporation completed a number of non-core asset dispositions from its Canadian asset base for aggregate net proceeds of approximately $21 million.

In December 2013, the Credit Facility was maintained at $115 million during the semi-annual redetermination.

Year Ended December 31, 2014

Chinook's 2014 Canadian and Tunisian capital expenditures (including property acquisitions) of $123 million focused on light oil development to replace less profitable production from normal declines associated with its Canadian natural gas properties. Approximately $97 million of the 2014 capital expenditures was spent in Canada and $26 million in Tunisia. The majority of

Chinook's 2014 Canadian capital expenditures ($41 million, representing 42% of Canadian capital expenditures) were incurred on its Karr, Beaverlodge, Albright and Gold Creek properties in the Grande Prairie area to drill 11 (7 net) wells in 2014, with the majority of the wells targeting high quality light oil from the Dunvegan (8 gross/5.6 net) and Montney (2 gross/1.12 net) formations. The majority of the balance of Chinook's 2014 Canadian capital expenditures ($52 million, representing 54% of Canadian capital expenditures) were incurred on its Birley/Umbach property in the Peace River Arch area to drill 3 (2.24 net) wells targeting liquids-rich Montney and acquire 28.3 sections (27.25 net) of undeveloped Montney lands.

During the first quarter of 2014, the Corporation drilled its first horizontal Montney well in the Birley/Umbach area at a-60-K/94-H-3 (75 per cent working interest). The well was drilled to a total measured depth of 2,700 metres with a 1,220 metre lateral section and was completed with an 18 stage nitrified slickwater fracture (65 tonnes per stage) stimulation.

In June 2014, the Credit Facility was increased to $125 million during the semi-annual redetermination, consisting of a $110 million syndicated credit facility and a $15 million operating facility.

On August 19, 2014, the Corporation's wholly-owned subsidiary, Storm Ventures International (BVI) Limited, completed the disposition, effective January 1, 2014, of all of the issued and outstanding shares of SVI Barbados, which directly and indirectly owned all of the Corporation's Tunisian assets for gross proceeds of approximately US$128.5 million (including positive working capital of approximately US$14.5 million). The net proceeds of the Tunisian Disposition were applied to eliminate the Corporation's bank indebtedness and to fund an expansion of the Corporation's 2014 Canadian capital program from $60 million to a total of $97 million. A portion of the expanded capital program funded additional drilling activity on the Corporation's acreage in the Birley/Umbach area of northeast British Columbia and in the Grande Prairie area of northwest Alberta, along with the front end costs associated with a facility expansion at Birley/Umbach.

On November 6, 2014, the Corporation acquired primarily natural gas producing properties near its Birley/Umbach operations along with operatorship of natural gas processing and transportation infrastructure for consideration of $17 million cash and 3.5 net undeveloped sections of mineral rights in the Wapiti area of Alberta.

In December 2014, the Credit Facility was maintained at $125 million during the semi-annual redetermination.

On December 18, 2014, the Corporation completed the disposition, effective July 1, 2014, of certain assets located in the Gilby area of Alberta for gross proceeds of $30.8 million, before customary closing adjustments.

Recent Developments

On January 6, 2015, the Corporation completed the disposition, effective October 1, 2014, of certain assets located in the Karr area of Alberta for gross proceeds of $40.9 million, before customary closing adjustments. The Corporation's fourth quarter 2014 average production from the Karr assets disposed of was approximately 430 BOE/d.

On January 19, 2015, the Corporation announced that it had reduced its 2015 capital program to approximately $45 million to maintain its strong balance sheet and capital flexibility through 2015. In addition, the Corporation will shut-in approximately 300 to 500 BOE/d of lower netback production in 2015. The Corporation advised that its strategy through 2015 is to utilize its capital flexibility and balance sheet strength to maintain optionality throughout a lower commodity price cycle as debt to cash flow levels amongst its peer group become challenged. The Corporation will continue to expand and delineate its large Montney resource in 2015 at a pace that does not impair its value creation or growth potential. By deferring facility installations, pipeline construction and a portion of its drilling program, the Corporation will not compromise its most economic rates of return by bringing new wells on production in the current weak price environment. The Corporation intends to drill four (3.6 net) Birley/Umbach wells and complete two (1.75 net) of these wells in 2015. Infrastructure expenditures at Birley/Umbach facilitating year-round access and program acceleration with stronger commodity prices will still be completed as part of the revised 2015 program.

Significant Acquisitions

The Corporation 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*.

DESCRIPTION OF THE BUSINESS

General

Chinook is a Calgary-based upstream oil and gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas. Chinook has exploration and production operations in western Canada.

Business Plan and Growth Strategies

The business plan of Chinook is to create sustainable and profitable growth in reserves, production and cash flow in the oil and natural gas industry in the Western Canadian Sedimentary Basin. As a pure domestic focused company with no debt, positive working capital and a Credit Facility of $125 million, Chinook is well positioned to accelerate the development of its recently announced Montney successes at Birley/Umbach where the Company holds 65 (54 net) sections of land, and at Grande Prairie where the Company holds 50 (35 net) sections of land. Chinook also anticipates that it will continue with its Dunvegan development drilling program at Albright/Beaverlodge in the Grande Prairie area where it plans further activity across four additional Company-owned Dunvegan pools. Strategic acquisitions within the Corporation's core areas will also become a focus for Chinook.

Chinook will continue to pursue internal and external generation of exploration plays that have low to medium risk and multi-zone potential. Chinook intends to maintain a balance between exploration, exploitation and development drilling in its core areas over the course of the next several years. Management of Chinook will consider asset and corporate acquisition opportunities from time to time that meet Chinook's business parameters.

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

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

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

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

Competitive Conditions

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

Cyclical Nature of Business

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, and wildlife restrictions will affect access in certain circumstances.

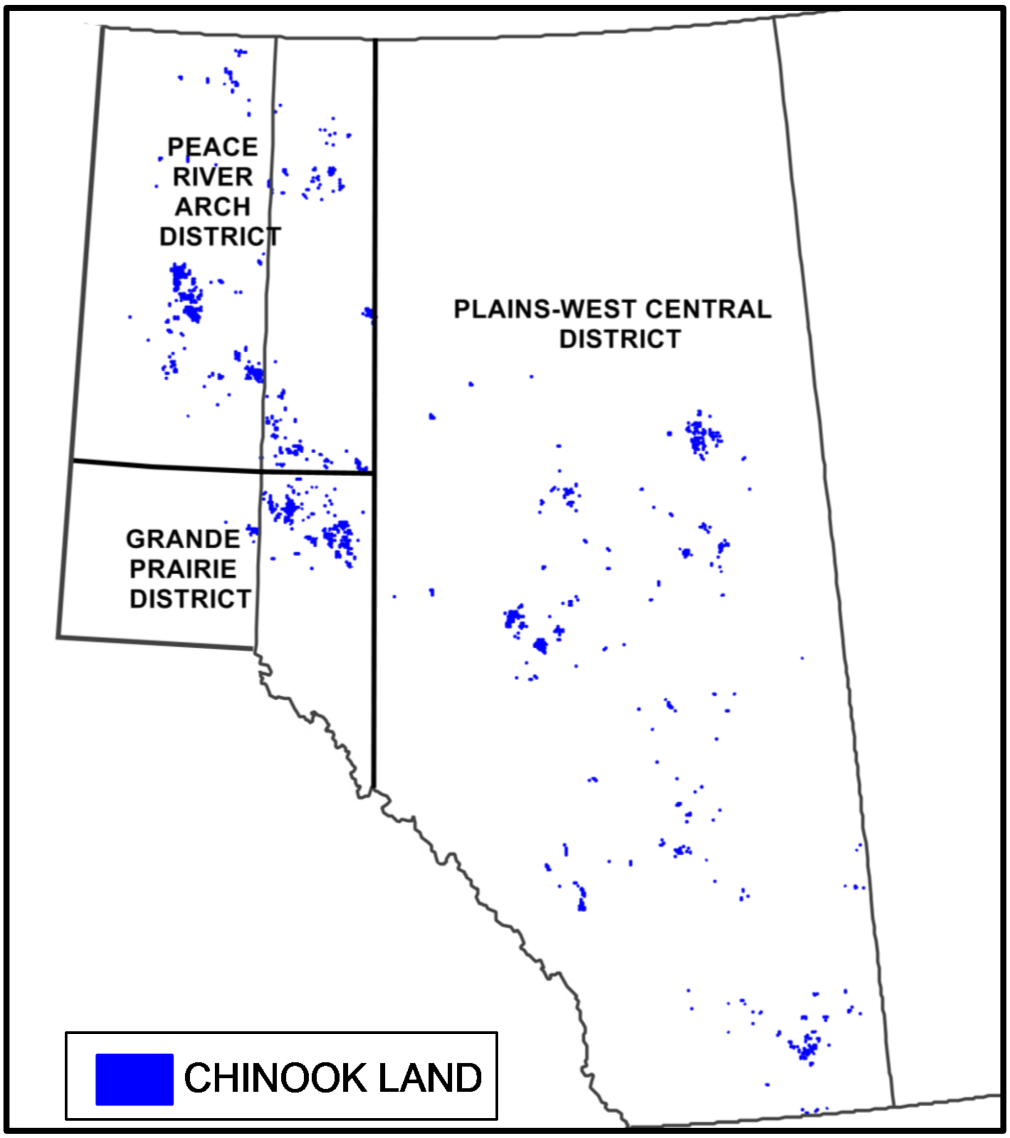
Employees and Consultants

As at December 31, 2014, Chinook had 63 full-time employees and 55 consultants/contract operators. As at December 31, 2014, 59 of the full-time employees and 12 of the consultants were located at Chinook's office in Calgary and four of the full-time employees and 43 of the field contract operators were located at Chinook's field based locations.

DESCRIPTION OF PRINCIPAL PROPERTIES

The following is a description of Chinook's principal oil and natural gas properties as at December 31, 2014. Unless otherwise indicated, production stated is average production for 2014 received in respect of Chinook's working interest share before deduction of royalties. Unless otherwise indicated, gross and net acres and well count information is as at December 31, 2014.

Chinook's principal designated western Canadian properties are shown in the following figure.



Plains-West Central District

The Plains-West Central District includes Chinook's assets largely east of the 6th Meridian and are the combination of previously described separate properties of the Plains District and the West Central District. The area includes major properties at Enchant-Grand Forks, Craigmyle, Atmore and Thornbury-Portage, Lochend, Paddle River and Whitecourt in Alberta. During 2014, dispositions of assets at Gilby occurred. Production from the assets owned by Chinook in the Plains-West Central District represented approximately 24% of Chinook's Canadian production during December 2014. Chinook holds an approximate 38% average producing working interest in such assets. The assets in the area are primarily operated. Production is from various Devonian, Mississippian, Jurassic and Cretaceous aged formations, including but not limited to Pekisko, Nordegg, Mannville, Ostracod, Glauconitic, Viking, Belly River and Edmonton zones. Production from the Plains-West Central District averaged 11,173 Mcf/d of natural gas and 599 Bbls/d of crude oil and natural gas liquids for the three months ended December 31, 2014.

Grande Prairie District

The Grande Prairie District includes Chinook's assets west of the 6th Meridian and south of Township 77, and includes major properties at Gold Creek, Karr, Wapiti, Albright, Knopcik and Valhalla. Production from the assets owned by Chinook in the Grande Prairie District represented approximately 38% of Chinook's Canadian production during December 2014. Chinook holds an approximate 50% average producing working interest in such assets. The assets in the area are largely operated. Production is primarily from Triassic and Cretaceous aged formations with a growing contribution from the Cretaceous Dunvegan formation. Production from the Grande Prairie District averaged 10,086 Mcf/d of natural gas and 1,698 Bbls/d of crude oil and natural gas liquids for the three months ended December 31, 2014.

Peace River Arch District

The Peace River Arch District includes Chinook's assets west of the 6th Meridian and north of Township 76, and includes major properties at Birley, Gordondale, Boundary Lake, Hotchkiss and Rainbow Lake. Chinook disposed of several assets at Monias, Boundary Lake and Gordondale and acquired assets at Martin Creek and Black-Conroy during 2014. Production from the assets owned by Chinook in the Peace River Arch District represented approximately 38% of Chinook's Canadian production during December 2014. Chinook holds an approximate 65% average producing working interest in such assets, excluding the effect of minor interest unit production amounting to approximately 0.1% of the total District production. The assets in the area are primarily operated. Production in the Birley area is primarily from the Montney formation. Production in the Gordondale, Boundary Lake and Hotchkiss areas is primarily from Mississippian, Jurassic and Cretaceous aged formations, while in Rainbow Lake the Keg River and Bluesky formations primarily produce. The acquired assets in the Martin Creek and Black-Conroy areas primarily produce from Baldonnel, Halfway, and Gething formations. Production from the Peace River Arch District averaged 13,625 Mcf/d of natural gas and 462 Bbls/d of crude oil and natural gas liquids for the three months ended December 31, 2014.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data set forth below is dated March 12, 2015. The effective date of the information is December 31, 2014. The reserves data is based upon an evaluation prepared by McDaniel with a preparation date of February 9, 2015.

Disclosure of Reserves Data

The Corporation engaged McDaniel to provide an evaluation of the Corporation's proved and proved plus probable reserves as at December 31, 2014. The reserves data set forth below (the "**Reserves Data**") is based upon the McDaniel Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by McDaniel & Associates Consultants Ltd. are attached as Schedules "A" and "B" hereto, respectively.

As at December 31, 2014, all of the Corporation's reserves are located in Canada and, specifically, in the provinces of Alberta and British Columbia.

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs, normal allocated overhead and future capital investments. 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, 2014 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	2,759	2,322	53	51	56,816	48,897	1,309	962	13,589	11,484
Non-Producing	516	443	0	0	9,928	8,151	209	157	2,380	1,958
Proved Undeveloped	566	487	0	0	7,084	6,269	231	196	1,978	1,728
Total Proved	3,841	3,252	53	51	73,828	63,317	1,749	1,315	17,947	15,170
Probable	1,911	1,475	43	41	39,118	32,989	963	720	9,437	7,734
Total Proved plus Probable	5,752	4,727	95	92	112,946	96,305	2,712	2,034	27,383	22,904

	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	($/BOE)
Proved Developed											
Producing	229.7	186.7	157.6	136.9	121.5	229.7	186.7	157.6	136.9	121.5	13.72
Non-Producing	33.7	22.3	15.4	11.0	8.0	33.7	22.3	15.4	11.0	8.0	7.88
Proved Undeveloped	27.1	14.7	7.7	3.3	0.3	27.1	14.7	7.7	3.3	0.3	4.47
Total Proved	290.4	223.6	180.7	151.2	129.7	290.4	223.6	180.7	151.2	129.7	11.91
Probable	195.7	119.0	80.8	58.9	45.1	182.1	113.9	78.7	57.9	44.6	10.44
Total Proved plus Probable	486.0	342.7	261.5	210.0	174.8	472.5	337.5	259.4	209.1	174.4	11.42

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2014 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	WELL ABANDONMENT COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Total Proved	859.3	95.1	409.8	42.6	21.3	290.4	0.0	290.4
Total Proved plus Probable	1,384.1	186.0	617.2	71.0	23.9	486.0	13.6	472.5

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/Bbl) ($/Mcf)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	97.8	$30.27/Bbl
	Heavy Oil (including solution gas and other by-products)	0.8	$14.89/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	93.5	$1.68/Mcf
	Coal Bed Methane (including by-products but excluding solution gas from oil wells)	(0.1)	$(0.76)/Mcf
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	141.6	$30.23/Bbl
	Heavy Oil (including solution gas and other by-products)	1.0	$11.31/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	130.0	$1.52/Mcf
	Coal Bed Methane (including by-products but excluding solution gas from oil wells)	0.0	$(0.14)/Mcf

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 McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

Reserve Categories

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, 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, natural gas and natural gas liquids benchmark reference pricing, inflation and exchange rates utilized by McDaniel were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL			NATURAL GAS	NGLs			
Year	**WTI Cushing Oklahoma ($US/Bbl)**	**Edmonton Oil Price 40° API ($Cdn/Bbl)**	**Hardisty Heavy 12° API ($Cdn/Bbl)**	**Natural Gas Alberta Spot Gas Price (1) ($Cdn/Mcf)**	**Edmonton Cond & Natural Gasoline ($Cdn/Bbl)**	**Butanes Price Edmonton ($Cdn/Bbl)**	**Inflation Rates (2) %/Year**	**Exchange Rate (3) ($US/$Cdn)**
Forecast								
2015	65.00	68.60	58.30	3.50	72.60	52.80	2.0	0.86
2016	75.00	83.20	70.70	4.00	87.30	67.00	2.0	0.86
2017	80.00	88.90	75.60	4.25	93.10	71.60	2.0	0.86
2018	84.90	94.60	80.40	4.50	98.80	76.20	2.0	0.86
2019	89.30	99.60	84.70	4.70	103.90	80.30	2.0	0.86
2020	93.80	104.70	89.00	5.00	109.10	84.40	2.0	0.86
2021	95.70	106.90	90.90	5.30	111.40	86.10	2.0	0.86
2022	97.60	109.00	92.70	5.50	113.60	87.80	2.0	0.86
2023	99.60	111.20	94.50	5.70	115.90	89.60	2.0	0.86
2024	101.60	113.50	96.50	5.90	118.30	91.50	2.0	0.86
2025	103.60	115.70	98.30	6.00	120.60	93.20	2.0	0.86
2026	105.70	118.00	100.30	6.10	123.00	95.10	2.0	0.86
2027	107.80	120.40	102.30	6.25	125.50	97.00	2.0	0.86
2028	110.00	122.80	104.40	6.35	128.00	99.00	2.0	0.86
2029	112.20	125.30	106.50	6.50	130.60	101.00	2.0	0.86
2030+	Escalated oil, gas and product prices at 2.0% per year thereafter							

Notes:
(1) Natural gas Alberta spot gas price at AECO.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2014, were $4.89/Mcf for natural gas, $88.18/Bbl for light and medium crude oil and $65.02/Bbl for NGLs.

4. Well abandonment costs for wells with reserves assigned have been included. Well abandonment costs for wells without reserves assigned have not been included. In addition, additional abandonment costs associated with lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

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

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

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, 2013	8,556	5,313	13,869	65	22	87
Extensions	265	144	410	-	-	-
Technical Revisions	50	(262)	(211)	48	(6)	42
Acquisitions	7	2	9	-	-	-
Dispositions (1)	(3,966)	(3,280)	(7,245)	-	-	(1)
Economic Factors	17	(7)	10	(22)	27	5
Production (2)	(1,089)	-	(1,089)	(37)	-	(37)
December 31, 2014	**3,841**	**1,911**	**5,752**	**53**	**43**	**95**

	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, 2013	1,301	825	2,126	65,666	37,176	102,842	20,866	12,357	33,222
Extensions	415	286	701	13,328	9,084	22,412	2,902	1,944	4,846
Technical Revisions	150	(19)	131	2,960	(1,533)	1,428	742	(542)	200
Acquisitions	428	95	524	16,449	3,650	20,098	3,177	705	3,883
Dispositions (1)	(231)	(215)	(446)	(12,222)	(8,720)	(20,942)	(6,234)	(4,948)	(11,182)
Economic Factors	(31)	(9)	(39)	(806)	(539)	(1,345)	(171)	(78)	(249)
Production (2)	(284)	-	(284)	(11,547)	-	(11,547)	(3,336)	-	(3,336)
December 31, 2014	**1,749**	**963**	**2,712**	**73,828**	**39,117**	**112,946**	**17,947**	**9,437**	**27,383**

Notes:
(1) Dispositions include volumes associated with the Tunisian Disposition completed effective January 1, 2014: Total Proved of (4,407) MBOE, Probable of (3,286) MBOE and Total Proved Plus Probable of (7,693) MBOE.
(2) Production includes volumes associated with the Tunisian Disposition completed effective January 1, 2014: Total Proved of (439) MBOE, Total Proved Plus Probable of (439) MBOE.

Subsequent to completion of the evaluation prepared by McDaniel with a preparation date of February 9, 2015, Chinook completed the disposition, effective October 1, 2014, of certain assets located in the Karr area of Alberta for gross proceeds of $40.9 million, before customary closing adjustments. The reserves associated with this disposition as evaluated effective December 31, 2014 total 888 MBOE and 1,304 MBOE on a Gross Proved and Gross Proved Plus Probable basis, respectively.

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 Chinook's assets for the years ended December 31, 2014, 2013 and 2012 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl) First Attributed	Light and Medium Oil (Mbbl) Cumulative at Year End	Heavy Oil (Mbbl) First Attributed	Heavy Oil (Mbbl) Cumulative at Year End	Natural Gas (MMcf) First Attributed	Natural Gas (MMcf) Cumulative at Year End	NGLs (Mbbl) First Attributed	NGLs (Mbbl) Cumulative at Year End
Prior thereto	794.5	4,992.7	-	-	1,472.4	6,834.5	45.0	138.0
2012	6,330.4	7,545.0	-	-	1,243.4	3,415.2	16.9	21.5
2013	735.7	1,189.8	-	-	1,115.3	1,539.4	20.3	27.6
2014	-	566.0	-	-	6,471.5	6,268.7	213.6	195.8

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl) First Attributed	Light and Medium Oil (Mbbl) Cumulative at Year End	Heavy Oil (Mbbl) First Attributed	Heavy Oil (Mbbl) Cumulative at Year End	Natural Gas (MMcf) First Attributed	Natural Gas (MMcf) Cumulative at Year End	NGLs (Mbbl) First Attributed	NGLs (Mbbl) Cumulative at Year End
Prior thereto	823.7	8,779.3	-	-	2,291.0	10,080.0	103.0	218.0
2012	599.5	720.0	-	-	733.6	8,787.6	17.4	153.3
2013	328.8	694.2	-	-	550.3	3,931.5	12.7	101.4
2014	-	318.9	-	-	13,301.2	10,024.9	438.9	300.0

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Chinook's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two to three years. 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 "Description of Principal Properties", "Statement of Reserves Data and Other Oil and Gas Information – Additional Information Related to Reserves Data – Future Development Costs" and "Statement of Reserves Data and Other Oil and Gas Information – 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**
2015	38.67	49.47
2016	1.61	12.62
2017	1.10	2.74
2018	-	-
2019	-	0.15
Thereafter	1.27	5.97
Total Undiscounted	42.65	70.95

On an ongoing basis, Chinook 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

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, 2014.

	Oil Wells				**Natural Gas Wells**				**Other Wells [1]**	
	Producing		**Non-Producing**		**Producing**		**Non-Producing**			
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	289.0	128.9	160.0	59.8	449.0	200.0	271.0	136.4	332.0	144.6
British Columbia	42.0	4.7	66.0	3.7	347.0	103.5	88.0	39.7	122.0	48.2
Saskatchewan	-	-	-	-	-	-	2.0	0.7	-	-
Total	331.0	133.6	226.0	63.5	796.0	303.5	361.0	176.8	454.0	192.8

Notes:
(1) Includes service, disposal, injection, water source and standing wells. This does not include abandoned wells.
(2) See "Description of Principal Properties" herein for a description of each of Chinook's material properties, as well as a description of the production associated with such properties.

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, 2014.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	540,261	270,005	294,594	153,414	834,855	423,419
British Columbia	188,575	103,237	141,620	89,278	330,195	192,515
Saskatchewan	364	136	631	471	995	606
Manitoba	-	-	80	13	80	13
Total	729,200	373,378	436,925	243,176	1,166,125	616,553

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

The Corporation expects that rights to explore, develop and exploit 37,803 net acres of its undeveloped land holdings will expire by December 31, 2015, a portion of which may be continued by drilling. Chinook plans to drill or submit application to continue selected portions of the above acreage.

Forward Contracts and Marketing

As of the date hereof, the Corporation has the following financial natural gas contract in place:

Commodity Contract	Period	Volume	Price
Natural gas contract	January 1, 2015 to December 31, 2015	5,000 GJs/d	Fixed price $3.50/GJ

Additional Information Concerning Abandonment and Reclamation Costs

Estimated future abandonment costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. 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 870 net 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 no allowance was made for reclamation of wellsites or the abandonment and reclamation of any facilities in the Reserve Report. The following table sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue:

Forecast Prices and Costs (MM$)

Year	Total Proved Abandonment Costs (Undiscounted)	Total Proved plus Probable Abandonment Costs (Undiscounted)
2015	-	-
2016	-	-
2017	-	-
2018	0.17	0.10
2019	0.28	0.19
2020	1.95	1.20
2021	1.92	1.46
2022	1.93	1.47
2023	1.35	1.31
2024	1.47	1.52
2025	1.00	1.10
2026	1.00	1.15
Thereafter	10.05	14.17
Total Undiscounted	21.12	23.67
Total Discounted @ 10%	7.07	6.51

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 $117 million, which will be incurred over an average of 17.87 years. The Corporation estimates that abandonment costs will approximate $1.0 million in each of the next three years.

Tax Horizon

Depending on the production, commodity prices and capital spending levels management believes that the Corporation will not have Canadian taxes payable in the immediate future as there are sufficient tax pools available to reduce future taxable income.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities, by country, for the year ended December 31, 2014:

CANADA	**(M$)**
Property acquisition costs	
Proved properties	15,850
Undeveloped properties	18,388
Exploration costs	11,537
Development costs	49,435
Corporate Acquisitions	-
Dispositions	(35,578)
Other	1,375
Total	61,007

TUNISIA (1)	**(M$)**
Property acquisition costs	
Proved properties	2,061
Undeveloped properties	-
Exploration costs	-
Development costs	22,508
Corporate Acquisitions	-
Dispositions	-
Other	1,489
Total	26,058

TOTAL	**(M$)**
Property acquisition costs	
Proved properties	17,911
Undeveloped properties	18,388
Exploration costs	11,537
Development costs	71,943
Corporate Acquisitions	-
Dispositions	(35,578)
Other	2,864
Total	87,065

Note:
(1) On August 19, 2014, the Corporation's wholly-owned subsidiary, Storm Ventures International (BVI) Limited, completed the Tunisian Disposition, effective January 1, 2014. The Corporation's reserve continuity does not reflect any changes, other than the removal of the opening Tunisian operations reserves, for these capital expenditures.

Exploration and Development Activities

The following table sets forth, by country, the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2014:

CANADA

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	-	-	9	6.14
Heavy Oil	-	-	-	-
Natural Gas	3	2.25	2	0.45
Dry	-	-	-	-
Service/Other	-	-	1	0.37
Stratigraphic Test	-	-	-	-
Total	**3**	**2.25**	**12**	**6.96**

TUNISIA

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	-	-	6	5.16
Heavy Oil	-	-	-	-
Natural Gas	-	-	-	-
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total	**-**	**-**	**6**	**5.16**

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

Production Estimates

The following tables disclose, by product, the total volume of the Corporation's gross production estimated by McDaniel for 2015 in the estimates of future net revenue from gross proved and gross probable reserves disclosed under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data".

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
From Gross Proved Reserves:	1,837	29	35,159	859	8,584
From Gross Probable Reserves:	271	17	3,937	113	1,056

Production History

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

	Quarter Ended 2014			
CANADA	**December 31**	**September 30**	**June 30**	**March 31**
Average Daily Sales Volumes [(1)]				
Light and Medium Crude Oil (Bbls/d)	1,981	1,823	2,267	2,084
Heavy Oil (Bbls/d)	-	-	-	-
Gas (Mcf/d)	34,879	29,028	29,570	29,364
NGLs (Bbls/d)	778	678	715	950
Combined (BOE/d)	8,572	7,339	7,911	7,928

CANADA	Quarter Ended 2014 December 31	September 30	June 30	March 31
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/Bbl)	70.84	93.10	101.01	96.41
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf) (2)	3.57	4.11	4.89	6.01
NGLs ($/Bbls)	48.05	64.71	72.06	74.10
Combined ($/BOE)	35.26	45.37	53.75	56.50
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	15.19	14.06	14.18	11.82
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	0.07	0.39	0.71	0.12
NGLs ($/Bbls)	10.22	20.13	19.41	20.47
Combined ($/BOE)	4.74	6.90	8.47	6.01
Operating Expenses				
Light and Medium Crude Oil ($/Bbls)	23.13	18.71	15.47	21.22
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	2.89	2.82	2.91	2.64
NGLs ($/Bbls)	19.51	17.69	19.25	12.95
Combined ($/BOE)	18.89	17.44	17.06	16.91
Netback Received (2)(3)				
Light and Medium Crude Oil ($/Bbls)	32.53	60.33	71.35	63.37
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	0.60	0.90	1.27	3.25
NGLs ($/Bbls)	18.31	26.89	33.40	40.69
Combined ($/BOE)	11.63	21.03	28.21	33.59

TUNISIA	Quarter Ended 2014 December 31 (5)	September 30 (5)	June 30	March 31
Average Daily Sales Volumes (1) (4)				
Light and Medium Crude Oil (Bbls/d)	-	22	1,346	1,623
Heavy Oil (Bbls/d)	-	-	-	-
Gas (Mcf/d)	-	730	1,475	1,475
NGLs (Bbls/d)	-	-	-	-
Combined (BOE/d)	-	144	1,592	1,869
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/Bbl)	-	105.17	118.17	117.91
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf) (2)	-	17.11	14.36	14.48
NGLs ($/Bbls)	-	-	-	-
Combined ($/BOE)	-	103.05	113.22	113.83
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	-	12.62	1.75	3.12
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	-	1.54	1.29	1.30
NGLs ($/Bbls)	-	-	-	-
Combined ($/BOE)	-	9.77	2.68	3.74
Operating Expenses				
Light and Medium Crude Oil ($/Bbls)	-	13.97	42.54	33.26
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	-	2.33	4.37	1.63
NGLs ($/Bbls)	-	-	-	-
Combined ($/BOE)	-	13.97	40.02	30.17

TUNISIA	Quarter Ended 2014 December 31 (5)	September 30 (5)	June 30	March 31
Netback Received (2)(3)				
Light and Medium Crude Oil ($/Bbls)	-	78.58	73.88	81.53
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	-	13.24	8.69	11.54
NGLs ($/Bbls)	-	-	-	-
Combined ($/BOE)	-	79.31	70.53	79.92

TOTAL	Quarter Ended 2014 December 31 (5)	September 30 (5)	June 30	March 31
Average Daily Sales Volumes (1)(4)				
Light and Medium Crude Oil (Bbls/d)	1,981	1,845	3,613	3,707
Heavy Oil (Bbls/d)	-	-	-	-
Gas (Mcf/d)	34,879	29,758	31,045	30,839
NGLs (Bbls/d)	778	678	715	950
Combined (BOE/d)	8,572	7,483	9,503	9,797
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/Bbl)	70.84	93.24	107.40	105.83
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf) (2)	3.57	4.43	5.34	6.42
NGLs ($/Bbls)	48.05	64.71	72.06	74.10
Combined ($/BOE)	35.26	46.48	63.71	67.44
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	15.19	14.04	9.55	8.01
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	0.07	0.42	0.74	0.18
NGLs ($/Bbls)	10.22	20.13	19.41	20.47
Combined ($/BOE)	4.74	6.96	7.50	5.57
Operating Expenses				
Light and Medium Crude Oil ($/Bbls)	23.13	18.65	25.55	26.49
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	2.89	2.81	2.98	2.59
NGLs ($/Bbls)	19.51	17.69	19.25	12.95
Combined ($/BOE)	18.89	17.37	20.91	19.44
Netback Received (2)(3)				
Light and Medium Crude Oil ($/Bbls)	32.53	60.55	72.29	71.32
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	0.60	1.20	1.62	3.65
NGLs ($/Bbls)	18.31	26.89	33.40	40.69
Combined ($/BOE)	11.63	22.15	35.30	42.43

Notes:

(1) Before deduction of royalties.
(2) Amounts from physical gas contracts are included in the gas prices shown.
(3) Netbacks are calculated by subtracting royalties, and operating and transportation costs, net of processing and gathering income, from revenues.
(4) The difference between the Corporation's Tunisian production and sales volumes is due to the difference between crude oil wellhead production as measured in the field, versus revenue recognition at the point when crude is loaded on to a tanker at a terminal port facility. The portion of crude oil production remaining as stored in the Corporation's tanks is reported as inventory.
(5) On August 19, 2014, the Corporation's wholly-owned subsidiary, Storm Ventures International (BVI) Limited, completed the Tunisian Disposition, effective January 1, 2014.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2014:

	Light and Medium Crude Oil (2) (Bbls/d)	Natural Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)
Grande Prairie, Canada	1,453	9,771	247	3,329
Peace River Arch, Canada	207	8,851	214	1,896
Plains-West Central Alberta, Canada	378	12,100	317	2,713
Adam Concession, Tunisia (1)	185	915	-	337
BBT Concession, Tunisia (1)	864	-	-	864
Total	3,087	31,637	779	9,139

Notes:

(1) On August 19, 2014, the Corporation's wholly-owned subsidiary, Storm Ventures International (BVI) Limited, completed the Tunisian Disposition, effective January 1, 2014.

(2) Information respecting production volumes of heavy oil has not been included in this table as Chinook's heavy oil production for the year ended December 31, 2014 was less than 2% of aggregate corporate production.

The Corporation's production for the year ended December 31, 2014 was approximately 34% light and medium quality crude oil (32° API or greater), 58% natural gas and 9% natural gas liquids.

For the twelve months ended December 31, 2014, approximately 57% of the Corporation's gross revenue was derived from crude oil production, 11% was derived from NGLs and 32% was derived from natural gas production.

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 with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta and British Columbia, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. 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

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, 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 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* (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. 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* (Canada).

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), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. 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 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 came into force 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 that 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. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%

Oil sands projects are also subject to 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 at 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, concurrent 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 new royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the Freehold Mineral Rights Tax Act (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "IETP") 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.

In addition, 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 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 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.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, 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 classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**EOR**") scheme. 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 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, beyond a certain production level, is determined using a sliding scale formula based on the production level. 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 production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

As of January 1, 2017 all liquid natural gas ("**LNG**") facilities will be subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment the British Columbia government will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

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

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells 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 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay if the re-entry well event is greater than 2,300 metres and a re-entry date after November 30, 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;

- *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 a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production.

To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m^3;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m^3 per metre of depth for exploratory wildcat wells and less than 11 m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m^3. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; 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 m3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that 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.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 6% minimum royalty on tier 1 wells and a 3% minimum royalty on tier 2 wells which claim the deep well/deep re-entry credits. The minimum royalty applies to tier 1 and tier 2 wells when the net royalty payable would otherwise be zero for a production month.

Land Tenure

The respective provincial governments predominantly own the rights to 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 and British Columbia have 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.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, 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 with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, 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 and the imposition of material fines and penalties.

Federal

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. 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.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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 seven 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.

Proclaimed in force in Alberta on October 1, 2009, the Alberta Land Stewardship Act (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are 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, licenses, registrations, 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 force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "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 OGAA 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*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, 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.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);
- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);
- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and
- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase was implemented in May of 2014 and the final phase will be implemented in May of 2015. The changes to the AB LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On July 4, 2014, the AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment.

British Columbia

In British Columbia, the Commission implements the Liability Management Rating ("**LMR**") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

The Government of Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "Action Plan") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. 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. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the Climate Change and Emissions Management Act (the "**CCEMA**") enacted on December 4, 2003 and amended 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 and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the Specified Gas Emitters Regulation ("**SGER**"), which imposes GHG limits, and the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes 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 by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 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 SGER. New Facilities are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that 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 CO2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also 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.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. 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 CO2 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 the 2012 Budget, British Columbia announced that the government would undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review last year, British Columbia confirmed that it will keep its revenue-neutral carbon tax, the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

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 *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG 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 Cap and Trade 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 development.

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 and should not 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. If any of the following risks or other risks occur, the Corporation's business, prospects, financial condition, results of operations and cash flows could be adversely affected in a material way.

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 its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able to 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, spills and 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.

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 or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines 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 and demand 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. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. 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, sanctions imposed on certain oil producing nations by other countries and 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.

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 the Organization of the Petroleum Exporting Countries ("**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.

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. Accordingly, the price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends 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 in accordance with 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;
- regulatory changes;
- 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.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering and processing facilities 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 have a material adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Competition

The petroleum industry is competitive in all of 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.

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 affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could also be adversely affected in a material way.

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, natural gas 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.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, 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 regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations 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).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes 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.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of 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 the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

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 legislation, 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.

Liability Management

Alberta and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. See "Industry Conditions – Liability Management Programs".

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 ("**GHG**") emissions legislation at the provincial or federal level. 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 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 GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. 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. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, Canadian/United States exchange rates could 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.

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 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 amount authorized under the Credit Facility is dependent on the borrowing base determined by the lenders. The Corporation is required to comply with covenants under the Credit Facility which include certain financial ratio tests and certain revenue and expenditure (including debt service) coverage ratio tests and, which may, from time to time, either affect the availability, or price, of existing and/or additional funding under the Credit Facility. 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 these covenants. A failure to comply with the applicable covenants (including the financial and coverage ratio tests) could result in default under the 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 the Credit Facility, the lenders under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The Credit Facility is secured by the Corporation's consolidated assets. The acceleration of the Corporation's indebtedness under the Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility may impose operating and financial restrictions on the Corporation that could include restrictions on paying dividends or repurchasing or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, providing guarantees, assuming loans, making capital expenditures, entering into amalgamations, mergers, take-over bids or disposing of assets, among others.

The Credit Facility lenders use the Corporation's consolidated reserves, commodity prices, applicable discount rates and other factors, to periodically determine the borrowing base under the Credit Facility. A material decline in commodity prices could reduce the borrowing base under the Credit Facility, reducing the funds available to the Corporation under the Credit Facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness thereunder.

Issuance of Debt

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

Hedging

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

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- 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 or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly 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 legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves 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 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 therefore does not reflect changes in the Corporation's reserves since that date.

Insurance

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

Control by Principal Shareholder

Her Majesty the Queen in Right of the Province of Alberta ("**HMQ**") owns 80,357,142 Common Shares, representing approximately 37.4% of the current outstanding Common Shares. Alberta Investment Management Corporation ("**AIMCo**"), as investment manager to HMQ, maintains investment control and direction over the Common Shares for the benefit of HMQ. Accordingly, AIMCo will have significant influence over the business and affairs of the Corporation and may have the ability to take shareholder actions irrespective of the vote of any other shareholders, including the ability to prevent certain transactions that it does not believe are in HMQ's best interest. This significant influence may discourage transactions involving a change of control of the Corporation, including transactions in which minority shareholders of the Corporation might otherwise receive a premium for the Common Shares over the then-current market price.

Furthermore, AIMCo will generally have the right (subject to applicable securities laws) at any time to sell the Common Shares held by HMQ or to sell HMQ's interest in the Corporation to a third party without the approval of the minority shareholders and without providing for a purchase of such shareholders' shares. Accordingly, the Common Shares held by minority shareholders may be less liquid and worth less than they would be if AIMCo did not have the ability to influence matters affecting the Corporation.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously 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 the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

The Corporation's properties are held in the form of 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.

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.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in 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.

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 the 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.

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. In addition, 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 decreases in the demand for the goods and services of the Corporation.

Third Party Credit Risk

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

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 risks 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, assumptions and uncertainties are found under the heading "Reader Advisory Regarding Forward-Looking Statements" of this Annual Information Form.

DIVIDENDS

The Corporation's current policy is to retain future profits for growth. As a result, no dividends have been paid on the Corporation's shares during the three most recently completed financial years. The Corporation's dividend policy is reviewed periodically by the Board of Directors and is subject to change, depending on earnings of the Corporation, financial requirements and other factors, as appropriate. As at the date hereof, the Corporation does not intend to change its dividend policy.

The Corporation's Credit Facility prohibits the Corporation from paying cash dividends on the Common Shares.

DESCRIPTION OF CAPITAL STRUCTURE

The following is a summary of the rights, privileges, restrictions and conditions attaching to the shares in Chinook's share capital.

Common Shares

Chinook is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Chinook. Subject to the rights of the holders of First Preferred Shares, and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors and upon liquidation, dissolution or winding-up of Chinook or other liquidation of assets of Chinook among its shareholders for the purposes of winding-up its affairs, to receive the remaining property of Chinook.

First Preferred Shares

Chinook is authorized to issue an unlimited number of first preferred shares ("**First Preferred Shares**") without nominal or par value. The First Preferred Shares are issuable in series and will have such rights, restrictions, conditions and limitations as the Board of Directors may from time to time determine subject to the following provisions. The First Preferred Shares will be entitled to priority over the Common Shares and all other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of assets of Chinook in the event of the liquidation, dissolution or winding-up of Chinook or other liquidation of assets of Chinook among its shareholders for the purposes of winding-up its affairs. The First Preferred Shares of each series will rank on parity with the First Preferred Shares of every other series with respect to priority in the payment of dividends and in the distribution of assets of Chinook in the event of the liquidation, dissolution or winding-up of Chinook or other liquidation of assets of Chinook among its shareholders for the purposes of winding-up its affairs.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX under the symbol "CKE". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares on the TSX as reported by the TSX for each month or, if applicable, partial month since the beginning of Chinook's most recently completed financial year.

Period	High ($)	Low ($)	Volume
2014			
January	1.53	1.12	6,126,296
February	1.45	1.16	2,365,165
March	1.44	1.22	4,210,180
April	2.10	1.30	6,186,823
May	2.39	1.72	7,341,012
June	2.85	2.05	12,837,511
July	2.60	2.07	22,491,021
August	2.43	1.98	6,738,598
September	2.45	1.89	6,430,637
October	2.18	1.33	12,315,081
November	1.86	1.42	7,218,308
December	1.47	1.08	5,994,199
2015			
January	1.30	0.97	4,995,933
February	1.41	1.13	1,442,877
March (1 to 11)	1.40	1.15	269,509

Prior Sales of Outstanding Unlisted Securities

During the year ended December 31, 2014, the only securities which Chinook issued which are outstanding but are not listed or quoted on a marketplace were the grant of options to purchase an aggregate of 2,443,000 Common Shares at exercise prices ranging from $1.26 to $2.46 per share and the grant of an aggregate of 212,570 restricted awards (entitling the holders to be issued 212,570 Common Shares as at December 31, 2014) and an aggregate of 255,355 performance awards (entitling the holders to be issued 255,355 Common Shares as at December 31, 2014, which assumes a payout multiplier of 1x for the grants) pursuant to Chinook's share award incentive plan.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of management of the Corporation, none of the securities of the Corporation are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

DIRECTORS AND EXECUTIVE OFFICERS

Name, Occupation and Security Holding

The following table sets forth certain information in respect of the Corporation's directors and executive officers.

Name, Province/State and Country of Residence	Position(s) with the Corporation [(1)]	Principal Occupation During the Five Years Preceding
Jill T. Angevine [(3)] Alberta, Canada	Director	Vice President and Portfolio Manager at Matco Financial Inc. (an independent, privately held asset management firm) since October 2013. Independent businesswoman from September 2011 until October 2013 and prior thereto, Vice President and Director, Institutional Research at FirstEnergy Capital Corp. (a financial advisory and investment services provider in the energy market).
Donald F. Archibald [(3)(4)] Alberta, Canada	Director	Independent businessman.
Matthew J. Brister Alberta, Canada	Chairman and Director	Independent businessman since December 31, 2013. Chief Executive Officer of Chinook from June 29, 2010 until December 31, 2013 (also President of Chinook from June 29, 2010 until March 1, 2012) and prior thereto, President and Chief Executive Officer of SVI.
Stuart G. Clark [(2) (3)] Alberta, Canada	Lead Director	Independent businessman.
Robert C. Cook [(2) (4)] Alberta, Canada	Director	Senior Vice President and Director, ARC Financial Corp. (a private equity management company).
Robert J. Herdman [(2)] Alberta, Canada	Director	Independent businessman since July 1, 2010 and prior thereto, Partner, PricewaterhouseCoopers LLP (accounting firm).
P. Grant Wierzba [(4)] Alberta, Canada	Director	Independent businessman since December 31, 2013. Vice President, Operations of Chinook from May 10, 2012 until December 31, 2013. Vice President, Production and Chief Operating Officer, Canada of Chinook from June 29, 2010 until May 10, 2012 and of SVI since May 2010. Prior thereto, Vice President, Operations of SVI.
Walter J. Vrataric Alberta, Canada	President and Chief Executive Officer	President and Chief Executive Officer of Chinook since December 31, 2013. President of Chinook from May 10, 2012 until December 31, 2013. Vice President, Business Development and Land of Chinook from June 29, 2010 until May 10, 2012 and prior thereto, a consulting landman of SVI.
Jason B. Dranchuk Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of Chinook since July 14, 2014. Vice President, Finance and Chief Financial Officer of Zargon Oil & Gas Ltd. (oil and gas company) from October 2010 until July 14, 2014 and prior thereto, Vice President, Finance and Controller of Zargon Oil & Gas Ltd.
Timothy S. Halpen Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Chinook since May 10, 2012. Vice President, Exploitation of Chinook from June 29, 2010 until May 10, 2012 and prior thereto, a consulting engineer of SVI.
S. Brent Dube Alberta, Canada	Vice President, Production	Vice President, Production of Chinook since March 1, 2012 and prior thereto, engineering and production projects consultant.

Name, Province/State and Country of Residence	Position(s) with the Corporation [(1)]	Principal Occupation During the Five Years Preceding
Ryan C. White Alberta, Canada	Vice President, Drilling and Completions	Vice President, Drilling and Completions of Chinook since January 1, 2012. Manager, Drilling and Completions of Chinook from June 29, 2010 until January 1, 2012 and prior thereto, of SVI.
Darrel G. Zacharias Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Chinook since January 1, 2012. Senior Geologist of Chinook from June 29, 2010 until January 1, 2012 and prior thereto, a consulting geologist of SVI.
Chad T. Lerner Alberta, Canada	Vice President, Land	Vice President, Land of Chinook since June 1, 2014. Senior landman of Chinook from August 2010 until June 1, 2014 and prior thereto, consulting landman.
Fred D. Davidson Alberta, Canada	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (law firm).

Notes:
(1) All of the directors of the Corporation have been appointed to hold office until the next annual general meeting of shareholders or until their successor is duly elected or appointed, unless their office is earlier vacated. Each of the directors other than Robert J. Herdman and Jill T. Angevine have been directors of the Corporation since June 29, 2010, the date of the Iteration Acquisition. Robert J. Herdman and Jill T. Angevine were appointed directors of the Corporation on July 13, 2010 and November 13, 2014, respectively. Each of Messrs Brister, Clark, Cook and Wierzba were directors of SVI from August 28, 2003, June 24, 2009, December 24, 2008 and August 28, 2003, respectively, until the date of the Iteration Acquisition. Mr. Archibald was a director of Iteration since May 7, 2008 until the date of the Iteration Acquisition.
(2) Member of the Audit Committee.
(3) Member of the Compensation, Nominating and Corporate Governance Committee.
(4) Member of the Reserves, Safety and Environmental Committee.
(5) The Corporation does not have an Executive Committee.

As at the date of this Annual Information Form, the number of Common Shares beneficially owned, or controlled or directed, directly or indirectly, by all of the directors and officers of the Corporation is 11,971,006 Common Shares, being approximately 6% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of Chinook, except as described below, no director or executive officer of Chinook (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Chinook), that: (a) was subject to a cease trade order (including a management 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, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Mr. Herdman, a director of Chinook, served as a director of SemBioSys Genetics Inc. ("**SemBioSys**") a development stage biotechnology company, until May 1, 2012. On May 25, 2012, the Alberta Securities Commission issued a cease trade order against SemBioSys for failure to file the required certification of interim filings for the interim period ended March 31, 2012. The securities commission of each of British Columbia, Manitoba, Ontario and Quebec issued similar orders in respect of the failure to file the certification of interim filings.

Bankruptcies

To the knowledge of Chinook, except as described below, no director or executive officer of Chinook (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Chinook to affect materially the control of Chinook: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Chinook) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this Annual Information Form, 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. Herdman, a director of Chinook, served as a director of SemBioSys until May 1, 2012. On June 22, 2012, a secured creditor of SemBioSys was granted an order under the *Bankruptcy and Insolvency Act* (Canada) appointing a receiver to take possession of and deal with specific assets of SemBioSys which had been pledged to that creditor.

Penalties or Sanctions

To the knowledge of Chinook, no director or executive officer of Chinook (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Chinook to affect materially the control of Chinook, 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.

Conflicts of Interest

Certain of the directors and officers of Chinook are engaged in, and may continue to be engaged in, other activities in the oil and natural gas industry from time to time. As a result of these and other activities, certain directors and officers of Chinook may; become subject to conflicts of interest from time to time. The ABCA provides that in the event that an officer or director 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 material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

None of the Corporation or any of its subsidiaries is a party to any legal proceeding nor was it a party to any legal proceeding during the financial year ended December 31, 2014, nor is the Corporation aware of any contemplated legal proceeding involving the Corporation or its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of the Corporation.

Regulatory Actions

During the financial year ended December 31, 2014, 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) any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of any director or executive officer of Chinook, any person or corporation that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Chinook's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect Chinook, other than as disclosed elsewhere in this Annual Information Form and as follows:

1. Pursuant to a management and administration services agreement between 1542991 Alberta Ltd. (a wholly-owned subsidiary of Chinook and the general partner of a limited partnership owned by nominees of AIMCo which holds the working interests in certain of Chinook's assets) and Chinook dated June 29, 2010, 1542991 Alberta Ltd. engaged Chinook to perform the duties of 1542991 Alberta Ltd. under the limited partnership agreement and to manage, administer and maintain the properties and the books, accounts and records of the limited partnership in connection with the limited partnership business and to make all decisions relating thereto. During the years ended December 31, 2012, 2013 and 2014, the calculated reimbursement due to Chinook pursuant to the management and administration services agreement was approximately $3.5 million, $4.0 million and $1.3 million, respectively. AIMCo, as investment manager to HMQ, maintains control and direction over approximately 37.4% of the outstanding Common Shares as at the date hereof for the benefit of HMQ.

2. Fred Davidson, the Corporate Secretary of Chinook, is a partner of Burnet, Duckworth & Palmer LLP, which firm receives fees for legal services provided to Chinook.

3. Stuart Clark, a director of Chinook, is a major shareholder of Alliance Trust Company which receives fees for transfer agent services provided to Chinook.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Alliance Trust Company at its principal office in Calgary, Alberta and at its agent's office in Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), the Corporation has not entered into any material contracts during the last financial year, or before the last financial year which are still in effect.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are McDaniel, the Corporation's independent engineering evaluators, and InSite Petroleum Consultants Ltd., the independent engineering evaluators who evaluated the Corporation's former Tunisian assets, (McDaniel and InSite Petroleum Consultants Ltd. are collectively referred to as the "**Experts**"), and KPMG LLP, the Corporation's independent auditors.

Interests of Experts

To the Corporation's knowledge, there were no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of its associates or affiliates: (i) held by an Expert or by the "designated professionals" (as defined in Form 51-102F2 to National Instrument 51-102) of such Expert, when such Expert prepared the report, valuation, statement or opinion referred to herein as having been prepared by such Expert; (ii) received by an Expert or by the "designated professionals" of such Expert, after the time specified above; or (iii) to be received by an Expert or by the "designated professionals" of such Expert; except in each case for the ownership of Common Shares, which in respect of each Expert and such

Expert's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares. In addition, none of the Experts, and no director, officer or employee of any of the Experts, 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.

KMPG LLP are the auditors of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

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 of the Corporation is attached hereto as Schedule "C".

Composition of the Audit Committee

The Audit Committee of the Corporation is currently comprised of Robert J. Herdman (Chair), Stuart G. Clark and Robert C. Cook. The following table sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
Robert J. Herdman (Chair) Calgary, Alberta	Yes	Yes	Mr. Herdman's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his in excess of 20 years experience as a senior audit partner with PricewaterhouseCoopers LLP (a public accounting firm) during which time Mr. Herdman had extensive dealings with audit committees and boards of large public companies, extensive exposure to the regulatory and compliance environment in Canada and the United States. Mr. Herdman received a Bachelor of Education degree from the University of Calgary. Mr. Herdman is a Chartered Accountant and is Fellow of the Institute of Chartered Accountants.
Stuart G. Clark Calgary, Alberta	Yes	Yes	Mr. Clark's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his in excess of 30 years of financial experience in the oil and gas industry, including as Chief Financial Officer of Pinnacle Resources Ltd. (a public oil and gas company) from July 1986 to July 1998, and subsequent thereto, Chief Financial Officer of Storm Energy Inc. (a public oil and gas company) from October 1998 to December 2000. He has also developed practical experience and understanding of procedures for financial reporting from his service on boards and audit committees of numerous publicly traded companies. Mr. Clark has a Bachelor of Commerce degree from the University of Manitoba.

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
Robert C. Cook Calgary, Alberta	Yes	Yes	Mr. Cook's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his in excess of 20 years experience in the oil and gas industry, including as Senior Vice President and Director of ARC Financial Corp., a private equity management company, since 2000. He has also developed practical experience and understanding of procedures for financial reporting from his service on boards and audit committees of numerous publicly traded companies. Mr. Cook holds a Bachelor of Engineering degree from McMaster University and an MBA from European University. Mr. Cook is a CFA Charter holder.

Pre-Approval of Policies and Procedures

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

The Audit Committee has determined that in order to ensure the continued independence of the auditors, only limited non-audit related services will be provided to the Corporation by KPMG LLP and in such case, only with the prior approval of the Audit Committee.

External Auditors Service Fees

The following table sets forth the audit service fees billed by the Corporation's external auditors for the periods indicated:

Type of Fees and Fiscal Year Ended	Aggregate Fees Billed	Description of Services
Audit Fees		
Fiscal Year Ended December 31, 2014	$392,500	Audit of consolidated financial statements
Fiscal Year Ended December 31, 2013	$544,430	Audit of consolidated financial statements, statutory audits
Audit – Related Fees		
Fiscal Year Ended December 31, 2014	$Nil	
Fiscal Year Ended December 31, 2013	$136,955	Matters in connection with internal controls over financial reporting and payroll specified audit procedures
Tax Fees		
Fiscal Year Ended December 31, 2014	$20,000	Tax compliance, tax advice and tax planning
Fiscal Year Ended December 31, 2013	$9,000	Tax compliance, tax advice and tax planning
All Other Fees		
Fiscal Year Ended December 31, 2014	$Nil	
Fiscal Year Ended December 31, 2013	$Nil	

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Chinook's securities and securities authorized for issuance under equity compensation plans will be contained in Chinook's information circular – proxy statement relating to the annual and special meeting of shareholders to be held on May 12, 2015. Additional financial information is provided in Chinook's audited consolidated financial statements and management's discussion and analysis for the financial year ended December 31, 2014.

Additional information relating to Chinook including the materials listed in the preceding paragraphs may be found on SEDAR at www.sedar.com.

SCHEDULE "A"

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

Management of Chinook Energy Inc. ("**the Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation'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, 2014, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. The reports of the independent qualified reserves evaluators are presented below.

The Reserves Committee of the Board of Directors of the Corporation has:

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

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

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

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

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

(b) the filing of Forms 51-101F2 which are the reports of the independent qualified reserves evaluators 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 12th day of March, 2015.

(signed) "*Walter J. Vrataric*"
Walter J. Vrataric
President and Chief Executive Officer

(signed) "*Timothy S. Halpen*"
Timothy S. Halpen
Chief Operating Officer

(signed) "*Donald F. Archibald*"
Donald F. Archibald
Director

(signed) "*Robert C. Cook*"
Robert C. Cook
Director

SCHEDULE "B"

REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD. IN ACCORDANCE WITH FORM 51-101F2

To the Board of Directors of Chinook Energy Inc. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue ($ thousands – before income taxes, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	Evaluation of P&NG Reserves of Chinook Energy Inc. as at December 31, 2014, prepared February 9, 2015	All of the Corporation's British Columbia, Alberta and Saskatchewan properties	-	261,491	-	261,491

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

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

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

   Executed as to our report referred to above.

MCDANIEL & ASSOCIATES CONSULTANTS LTD.
Calgary, Alberta, Canada, February 9, 2015.

Per: (signed) "*Phil Welch*"
Phil Welch, P. Eng.
President and Managing Director

SCHEDULE "C"

CHINOOK ENERGY INC.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Role and Objective

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

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

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

The primary objectives of the Committee are as follows:

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

Membership of Committee

1. The Committee will be comprised of at least three (3) directors or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in 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. Satisfy itself on behalf of the Board with respect to Chinook's internal control systems.

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

    - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;

    - reviewing significant accruals, provisions or other estimates such as the impairment 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;

    - monitoring the effectiveness of the financial reporting environment; and

    - obtaining explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses and other offering documents, 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 Chinook's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. Review and approve the disclosure of audit committee information required to be included in the AIF of the Corporation prior to its filing with regulatory authorities.

6. With respect to the appointment of the 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, assess the reasonableness of the audit fee;

    - on an annual basis, conduct an assessment of the external auditor's performance;

- 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 Chinook 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 the external auditors (and internal auditor if one is appointed by Chinook) their assessment of the internal controls of Chinook, 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 consider the impact of business risks of the Corporation on the audit plan. The Committee will monitor the execution of the audit plan, with emphasis on the more complex and risky areas of the audit. Upon completion of the audit, the Committee will review annually with the external auditors their report upon the consolidated financial statements of Chinook and its subsidiaries and the Committee will evaluate the audit findings contained in the audit report.

8. Review with the external auditors on an annual basis the Canadian Public Accountability Board's ("**CPAB**") public inspection results report and, in a year when the Corporation's file is inspected by CPAB, the Committee will also review with the external auditors the inspection findings contained in such report.

9. Review risk management policies and procedures of Chinook (i.e. hedging, litigation and insurance) and consider the impact of business risks on the audit plan.

10. Establish a procedure for:

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

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

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

12. Satisfy itself on behalf of the Board with respect to the expense account of the Chief Executive Officer of Chinook, which expense account shall be reviewed at least annually by the Chairman of the Committee.

13. Complete a comprehensive review of the external audit firm on a periodic basis, once every five years at minimum, which comprehensive review will generally include an evaluation of the following:

    - trends in the audit firm's performance, industry expertise and professional skepticism;

    - the quality control environment of the audit firm, including safeguards against independent threats;

    - the quality of thought, leadership and transparency of communications on any controversial matters;

    - the results of annual assessments, how the firm has responded to those assessments and how the firm handled any partner rotations during the period; and

- the quality of the engagement team.

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

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Chinook 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 will be entitled to a second or casting vote.

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

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

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

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

6. Agendas will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

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

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

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

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as two members remain on the Committee. 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.