CHINOOK
energy inc

ANNUAL INFORMATION FORM

for the year ended December 31, 2017

March 14, 2018

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

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

SCHEDULE "C" - AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbl	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbl	million barrels	MMcf/d	million cubic feet per day
Bbls/d	barrels per day	MMbtu	million British Thermal Units
NGLs	natural gas liquids	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
M$	thousands of dollars
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);

"**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;

"**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;

"**Craft**" means Craft Oil Ltd. (formerly 1947577 Alberta Ltd.), a former subsidiary of the Corporation;

"**Craft Shares**" means the common shares in the capital of Craft;

"**Craft Share Distribution**" means the distribution of all of the Craft Shares held by Chinook, being 152,251,953 Craft Shares, to Shareholders as at 4:00 p.m. (Calgary time) on December 12, 2016 pursuant to a plan of arrangement under the ABCA;

"**Credit Facility**" means the Corporation's $18 million demand revolving credit facility with a financial institution subject to periodic review from time to time with the next scheduled semi-annual review being on or before May 31, 2018, which facility is secured by the Corporation's consolidated assets;

"**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 13, 2018 evaluating all of Chinook's crude oil, natural gas liquids and natural gas reserves as at December 31, 2017, 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;

"**Subject Assets**" has the meaning ascribed thereto under "General Development of the Business – Year Ended December 31, 2016";

"**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;

"**Tournament**" has the meaning ascribed thereto under "General Development of the Business – Year Ended December 31, 2016";

"**Tournament Transaction**" has the meaning ascribed thereto under "General Development of the Business – Year Ended December 31, 2016";

"**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, 2017.

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 2018 and the expectation that such amounts will be spent in the manner, location and timeframes set forth herein, expectations of drilling and operational plans in 2018 and the timing thereof, how the Corporation intends to be managed, 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, unanticipated third party restrictions, the voluntary shut-in of volumes in response to weak natural gas prices, 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, risks relating to indemnification rights, 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.". On December 12, 2016, in connection with the plan of arrangement to complete the Craft Share Distribution, the Corporation's articles were amended and restated to: (i) increase the voting rights of the old Common Shares from one (1) vote per old Common Share to two (2) votes per old Common Share; (ii) authorize the Corporation to issue an unlimited number of new Common Shares as an additional class of shares of the Corporation's share capital; and (iii) cancel the old Common Shares from the share capital which the Corporation was authorized to issue and rename the new Common Shares as "Common Shares".

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 in place at December 31, 2017 accounted for (i) less than 10% of the Corporation's consolidated assets as at December 31, 2017, and (ii) less than 10% of the Corporation's consolidated revenues for the year ended December 31, 2017. In the aggregate, the subsidiaries accounted for less than 20% of each of (i) and (ii) described 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, 2015

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.

During 2015, as commodity prices continued to weaken, Chinook proactively managed its production and remained focussed on cost savings and implementing a strategic capital program which allowed it to take advantage of lower service and supplier pricing. Even with a contracted capital program in 2015 of $48.6 million (excluding net property dispositions), Chinook continued to prudently delineate its large Montney position at its Birley/Umbach property in northeast British Columbia and delivered strong results with improved capital efficiencies along with receiving positive technical revisions as a result of wells performing above type curve estimates. Chinook drilled a total of three horizontal operated wells (2.75 net) targeting liquids-rich natural gas in the Montney formation on its Birley/Umbach property. All three of these wells, plus another Birley/Umbach well (0.75 net) drilled in 2014 were completed in 2015. Chinook also substantially completed the 25 MMcf/d expansion of its Birley/Umbach compressor during 2015.

In December 2015, the borrowing base of the Corporation's former term credit facility with a syndicate of financial institutions was set at $50 million during the semi-annual redetermination, down from $75 million at June 30, 2015 and $125 million at December 31, 2014, primarily as a result of reduced commodity pricing and non-core asset dispositions.

Year Ended December 31, 2016

In 2016, Chinook remained committed to prudently and efficiently developing its large Montney position at its Birley/Umbach property during a period of depressed natural gas prices. In addition, Chinook continued to focus on capital discipline and cost control while maintaining its commitment to safety. Chinook's 2016 capital expenditures before acquisitions and divestitures of $11.9 million were focussed on the completion of the 25 MMcf/d expansion of the Corporation's Birley/Umbach facility, the Corporation's abandonment program and the drilling of three gross (2.67 net) wells at Birley/Umbach.

In February 2016, the 25 MMcf/d expansion of the Corporation's Birley/Umbach facility was completed and came on stream and resulted in a net increase to the Corporation's throughput capacity to 29 MMcf/d.

On June 10, 2016, Chinook completed the divestiture of the majority of its Alberta oil and natural gas assets, excluding its Montney assets (the "**Subject Assets**") with an effective date of May 1, 2016, to Tournament Exploration Ltd. ("**Tournament**"), a private oil and natural gas company, for 152,251,953 common shares in Tournament (the "**Tournament Transaction**") representing approximately 70% of the issued and outstanding share capital of Tournament upon closing of the Tournament Transaction. In connection with the Tournament Transaction, Chinook also made a payment of $925,000 to Tournament. Concurrent with Chinook's contribution of the Subject Assets to Tournament, WOGH Limited Partnership, a wholly-owned subsidiary of Chinook's major shareholder, AIMCo, on behalf of certain of its clients, contributed producing and undeveloped properties in similar areas net of associated decommissioning obligations and $2,000,000 to acquire 10% of Tournament's issued and outstanding common shares pursuant to the Tournament Transaction. Following the Tournament Transaction, Chinook voluntarily reduced the borrowing base of its undrawn former term credit facility from $50 million to $nil, as a result of the transfer of the Subject Assets to Tournament.

On June 22, 2016, the Corporation completed the disposition, effective May 1, 2016, of certain of its assets located in the Gold Creek area of Alberta for aggregate consideration of approximately $7.5 million, subject to customary closing adjustments. Upon completion of the disposition, Chinook retained 24.5 sections (16.5 net) and 35 sections (20.5 net) of Montney lands at Gold Creek and Knopcik, respectively, and retained ownership of the two (1.13 net) horizontal Montney wells it drilled at Gold Creek in 2014.

On August 2, 2016, Chinook announced that it had initiated a review of strategic alternatives, which included, among other things, a review of acquisition opportunities to expand its core Montney asset base, or establish a new core area of operations. Chinook also entertained merger, sale, joint venture or other opportunities that would result in a well-capitalized entity that could best develop its emerging Montney assets at Birley/Umbach, British Columbia and at Gold Creek, Alberta.

On October 31, 2016, Chinook exchanged all of its common shares of Tournament on a one (1) for one (1) basis for 152,251,953 common shares of 1947577 Alberta Ltd., which was subsequently renamed Craft Oil Ltd.

On December 12, 2016, Chinook completed the Craft Share Distribution pursuant to a plan of arrangement under the ABCA. The plan of arrangement was approved by 99.98% of the votes cast by Shareholders present in person or represented by proxy at Chinook's special meeting of Shareholders held that day. Pursuant to the plan of arrangement, each old Common Share outstanding as at 4:00 p.m. (Calgary time) on December 12, 2016 was exchanged for one new Common Share and 0.70343 of a Craft Share. The Craft Share amount represents the pro-rata entitlement per old Common Share to the 152,251,953 Craft Shares held by Chinook, immediately prior to the effective time, based on the old Common Shares issued and outstanding at such time.

Year Ended December 31, 2017

In 2017, Chinook remained committed to prudently and efficiently developing its large Montney position at its Birley/Umbach property during a period of depressed natural gas prices. In addition, Chinook continued to focus on capital discipline and cost control while maintaining its commitment to safety. Chinook's 2017 capital expenditures before acquisitions and divestitures of $39.0 million were focused on the drilling, completion and tie-in of four (3.63 net) wells at Birley/Umbach and the expansion of Chinook's 25 MMcf/d compressor station at Birley/Umbach to 50 MMcf/d.

On January 4, 2017, Chinook announced that it had successfully completed its three well (2.62 net) drilling program at Birley/Umbach. The drilling of these wells was completed on schedule and under budget by approximately 26% with average drilling costs of approximately $1.28 million per well ($1.12 million, net). Chinook also announced that it had secured an $8 million demand revolving facility with a financial institution which replaced its previous term credit facility. Chinook also announced that it had entered into hedges to fix the AECO price of natural gas on 7,500 GJs/d of natural gas production at an average of $3.205 per GJ for 2017 and that it had concluded its ongoing review of strategic alternatives as announced on August 2, 2016.

On January 23, 2017, Chinook completed the sale of certain of its non-core assets located in the Knopcik/Pipestone area of Alberta for net consideration of approximately $7.5 million, subject to customary closing adjustments pursuant to a sale agreement dated January 20, 2017. The assets included 15.8 net sections of land, of which 5.25 net sections would have necessitated drilling activity in 2017 prior to expiry. The disposition had nominal impact on Chinook's funds flow or reserves.

On February 1, 2017, Chinook completed the disposition, effective February 1, 2017, of certain of its assets located in the Gold Creek area of Alberta for net consideration of approximately $10.5 million, subject to customary closing adjustments. The divested assets included 15.6 net sections of land and related pipelines and production facilities.

On November 9, 2017, Chinook announced that it had secured the Credit Facility which provided Chinook with $10 million of additional availability from its previous demand revolving facility.

On December 11, 2017, Chinook completed a private placement of 6,450,000 flow-through Common Shares at $0.31 per share for total consideration of $2.0 million. Proceeds from this private placement will be used to fund the two well drilling program discussed further below.

On December 22, 2017, Chinook completed the expansion of its 25 MMcf/d compressor station at Birley/Umbach to 50 MMcf/d which enables Chinook to have the capacity to produce all of its 13 (11.27 net) Birley/Umbach wells.

Recent Developments

On January 17, 2018, Chinook announced that its Board of Directors approved a $3.4 million capital program for the first half of 2018 funded predominately by the private placement of flow-through Common Shares completed on December 11, 2017. This capital program for the first half of 2018 included the drilling of two (2.0 net) vertical wells in the Birley/Umbach area as well as other minor expenditures. During the first quarter of 2018, Chinook drilled the two vertical wells at a cost of $2.1 million to help delineate 17 undrilled contiguous sections of 100% owned Montney rights (located three kilometres north of Chinook's main Montney landblock and eight kilometres from the nearest well drilled into the Montney) by evaluating the pay thickness and reservoir quality throughout the entire 235 metre thick Montney zone.

During the first quarter of 2018, Chinook entered into a commodity price contract to fix the Chicago City Gate index price of 6,000 MMbtu/d of natural gas at US$2.68/MMbtu from February 1, 2018 to March 31, 2019.

On March 8, 2018, Chinook announced that it continues to produce at volumes less than its capability due to gathering system maintenance issues on the Oak Pipeline which are expected to be temporarily resolved by April 2018. In anticipation of weaker natural gas prices, Chinook may voluntarily shut-in volumes through the summer months as it does not have large take or pay commitments that would force it to produce at low prices. Chinook also announced that it remains cautious on making further capital expenditures until such time as commodity prices improve to a more constructive level. The capital program for the balance of 2018 will be minimal and continuously reviewed by management and the Board of Directors with adjustments made in response to changing market conditions.

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 natural gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas. Chinook is focussed on realizing per share growth from its large contiguous Montney liquids-rich natural gas position at its Birley/Umbach property in northeast British Columbia.

Business Plan and Growth Strategies

Chinook's business plan for 2018 is to remain committed to prudently and efficiently developing its large contiguous Montney resource across its Birley/Umbach lands. Chinook will continue to focus on capital discipline and cost control while maintaining its commitment to safety. Currently, Chinook remains cautious on making further capital expenditures until such time as commodity prices improve to a more constructive level. The capital program for the balance of 2018 will be minimal and continuously reviewed by management and the Board of Directors with adjustments made in response to changing market conditions. In anticipation of increased commodity prices, Chinook is well positioned to accelerate the development of its extensive Montney resource at Birley/Umbach in northeastern British Columbia where the Corporation holds 76 (63 net) drill spacing units ("**DSUs**") of land where management estimates 291 gross potential drilling locations based on four wells per DSU of which 19 gross (16.1 net) are booked as Proved Undeveloped locations and 14 gross (11.3 net) are booked as Probable Undeveloped locations. Chinook will continue to evaluate additional asset and corporate acquisition opportunities that meet Chinook's business strategies.

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.

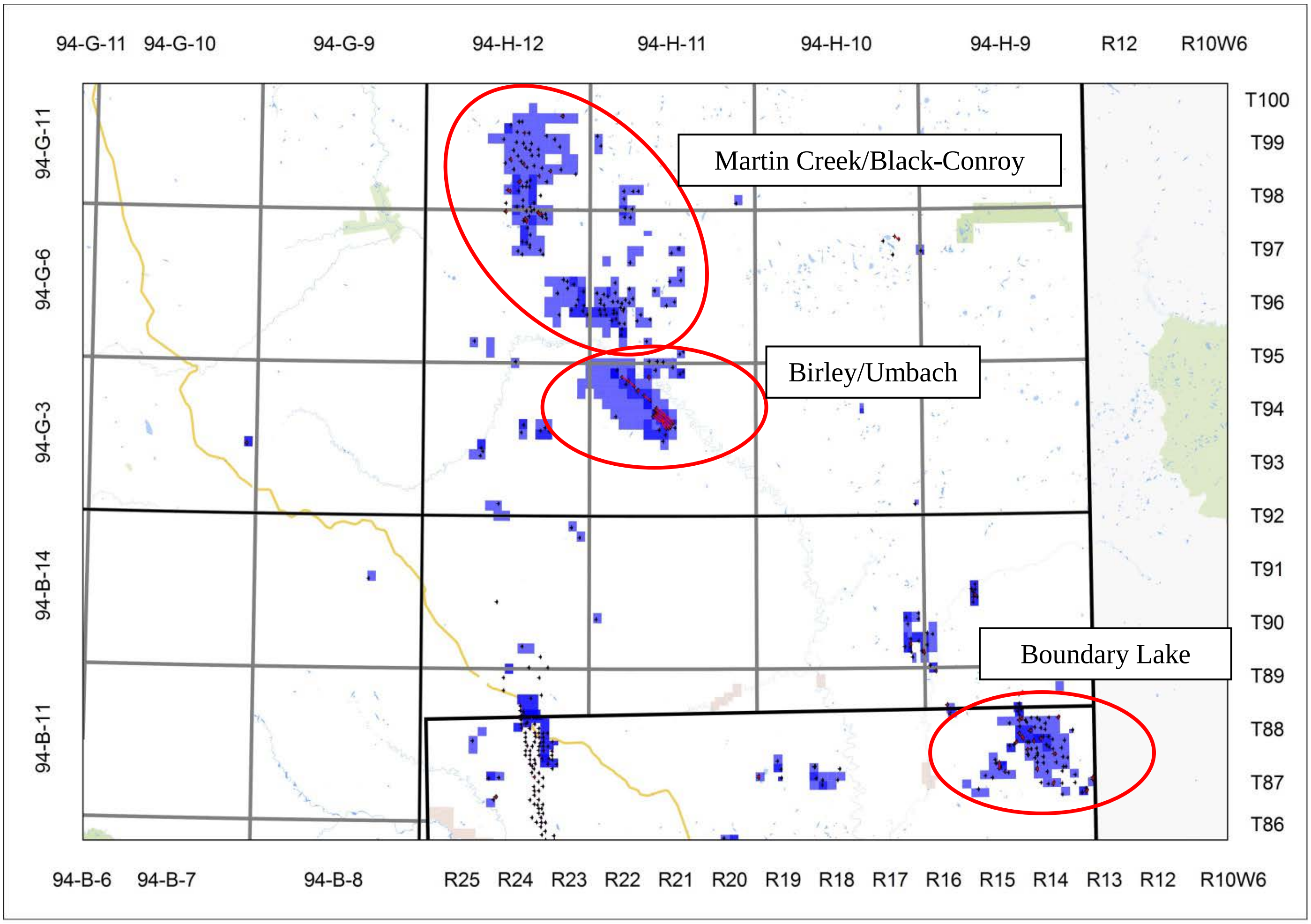
Employees and Consultants

As at December 31, 2017, Chinook had 23 full-time employees and 20 consultants/contract operators. As at December 31, 2017, 23 of the full-time employees and 5 of the consultants were located at Chinook's office in Calgary and 15 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, 2017. Unless otherwise indicated, production stated is average production for 2017 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, 2017.

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


94-G-11
94-G-10
94-G-9
94-H-12
94-H-11
94-H-10
94-H-9
R12
R10W6
T100
T99
T98
T97
T96
T95
T94
T93
T92
T91
T90
T89
T88
T87
T86
94-G-11
94-G-6
94-G-3
94-B-14
94-B-11
Martin Creek/Black-Conroy
Birley/Umbach
Boundary Lake
94-B-6
94-B-7
94-B-8
R25
R24
R23
R22
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R20
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R13
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R10W6

Birley/Umbach, Northeast British Columbia

Chinook's land holdings in the Birley/Umbach area of northeast British Columbia total 48,328 net acres, or 69 net DSUs of which 31,350 net acres include Montney rights. Production in 2017 from this area averaged 10,342 Mcf/d of natural gas and 295 Bbls/d of condensate and natural gas liquids. Production from Birley/Umbach was affected in 2017 by the extended McMahon gas plant turnaround in June, July and August. The field was shut in or materially restricted during this period of approximately 66 days.

In 2017, Chinook completed and tied-in three wells and drilled, completed and tied-in an additional four wells. Chinook also expanded its central compressor station (84% working interest) from 25 MMcf/d to 50 MMcf/d.

The Birley/Umbach area remains the focus of Chinook's development and growth strategy.

Martin Creek/Black-Conroy, Northeast British Columbia

Chinook holds a total of 75,756 net acres, or 108 net DSUs in the Martin Creek/Black-Conroy area. This property is adjacent to the Birley/Umbach lands which are approximately two miles to the south. While the area is predominantly legacy production, Chinook has accumulated 11,950 net acres of prospective Montney rights in the area. Chinook drilled two vertical wells delineating the Montney formation on these lands in the first quarter of 2018. Results from these wells remain confidential. The area averaged 4,481 Mcf/d of natural gas and 138 Bbls/d of condensate and natural gas liquids in the fourth quarter. Production is currently from the Halfway, Baldonnel and Bluesky formations. Production from the Martin Creek/Black-Conroy area was also affected in 2017 by the extended McMahon gas plant turnaround in June, July and August. The field was shut in or materially restricted during this period of approximately 66 days.

Boundary Lake, Northeast British Columbia

Chinook holds a total of 23,482 net acres, or 34 net sections in the Boundary Lake area of which 3,395 net acres include Montney rights, although the Corporation currently does not view the Montney in this area as commercially prospective. Production in 2017 from this area averaged 2,389 Mcf/d of natural gas and 37 Bbls/d of condensate and natural gas liquids. Production from Boundary Lake was also affected, although to a lesser extent, in 2017 by the extended McMahon gas plant turnaround in June, July and August. The field was shut in during a period of approximately 40 days.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data set forth below is dated March 14, 2018. The effective date of the information is December 31, 2017. The reserves data is based upon an evaluation prepared by McDaniel with a preparation date of February 13, 2018.

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, 2017. 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, 2017, 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, 2017 FORECAST PRICES AND COSTS

RESERVES CATEGORY	RESERVES: LIGHT AND MEDIUM OIL Gross (Mbbl)	Net (Mbbl)	HEAVY OIL Gross (Mbbl)	Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (MMcf)	Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	Net (Mbbl)	TOTAL Gross (MBOE)	Net (MBOE)
Proved Developed										
Producing	6	6	-	-	41,786	36,582	1,130	954	8,101	7,056
Non-Producing	7	6	-	-	1,473	1,301	46	37	298	260
Proved Undeveloped	-	-	-	-	52,242	44,060	1,540	1,309	10,247	8,652
Total Proved	13	12	-	-	95,502	81,942	2,716	2,299	18,646	15,968
Probable	6	6	-	-	78,500	63,264	2,175	1,780	15,264	12,330
Total Proved plus Probable	19	17	-	-	174,002	145,206	4,891	4,079	33,910	28,298

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE)
Proved Developed											
Producing	54.3	48.9	44.0	39.9	36.6	54.3	48.9	44.0	39.9	36.6	6.23
Non-Producing	3.9	3.1	2.5	2.1	1.8	3.9	3.1	2.5	2.1	1.8	9.77
Proved Undeveloped	77.5	52.1	35.5	24.4	16.6	77.5	52.1	35.5	24.4	16.6	4.11
Total Proved	135.7	104.1	82.1	66.4	55.1	135.7	104.1	82.1	66.4	55.1	5.14
Probable	190.0	112.7	72.1	49.1	35.0	190.0	112.7	72.1	49.1	35.0	5.85
Total Proved plus Probable	325.7	216.8	154.2	115.5	90.1	325.7	216.8	154.2	115.5	90.1	5.45

Properties assigned reserves which are not producing but are capable of production include wells in Boundary Lake North, Kaybob, Kelly, Martin Creek and Nig Creek. Specific wells within these areas have been in their current state ranging from initial drilling or completion in 1993 to shut-in of the well in 2015. In some cases, non-producing reserves are assigned to wells that are currently producing from other zones. All wells are tied-in to existing infrastructure. Production from these wells may be dependent on recompletion or minor equipment capital, depletion of other producing zones in the wellbore or pipeline reconfigurations. Properties assigned reserves which are not producing account for approximately 1.6% of Total Proved and 1.2% of Total Proved plus Probable reserves.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2017 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	ABANDONMENT AND RECLAMATION COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Total Proved	510.4	47.9	228.5	83.7	14.5	135.7	-	135.7

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	ABANDONMENT AND RECLAMATION COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Total Proved plus Probable	1,017.2	120.5	414.1	139.1	17.8	325.7	-	325.7

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2017
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCT TYPE	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)	0.1	$7.48/Bbl
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)	82.0	$1.00/Mcf
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	0.2	$10.34/Bbl
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)	154.0	$1.06/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. Abandonment and reclamation costs were deducted in estimating the Corporation's future net revenue set forth above. For a discussion on abandonment and reclamation costs, see "Statement of Reserves Data and Other Oil and Gas Information – Additional Information Concerning Abandonment and Reclamation Costs".

4. 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)	Natural Gas Alberta Spot Gas Price (1) ($Cdn/MMBtu)	British Columbia Plantgate Gas Price ($Cdn/MMBtu)	Edmonton Cond & Natural Gasoline ($Cdn/Bbl)	Butanes Price Edmonton ($Cdn/Bbl)	Inflation Rates (2) %/Year	Exchange Rate (3) ($US/$Cdn)
Forecast								
2018	58.50	70.10	2..25	1.65	73.10	51.40	0.0	0.790
2019	58.70	71.30	2.65	2.15	74.40	52.20	2.0	0.790
2020	62.40	74.90	3.05	2.55	78.00	54.90	2.0	0.800
2021	69.00	80.50	3.40	3.00	83.70	59.00	2.0	0.825
2022	73.10	82.80	3.60	3.20	86.00	60.70	2.0	0.850
2023	74.50	84.40	3.65	3.25	87.70	61.80	2.0	0.850
2024	76.00	86.10	3.75	3.25	89.50	63.10	2.0	0.850
2025	77.50	87.80	3.80	3.30	91.20	64.30	2.0	0.850
2026	79.10	89.60	3.90	3.40	93.10	65.60	2.0	0.850
2027	80.70	91.40	3.95	3.45	95.00	67.00	2.0	0.850
2028	82.30	93.20	4.05	3.55	96.90	68.30	2.0	0.850
2029	83.90	95.00	4.15	3.65	98.70	69.60	2.0	0.850
2030	85.60	97.00	4.25	3.75	100.80	71.10	2.0	0.850
2031	87.30	98.90	4.30	3.80	102.80	72.50	2.0	0.850
2032	89.10	100.90	4.35	3.85	104.90	73.90	2.0	0.850
2033+	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 on an unconsolidated basis for the year ended December 31, 2017, were $1.95/Mcf for natural gas, $62.28/Bbl for light and medium crude oil and $47.89/Bbl for NGLs.

5. 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.

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

7. The extent and character of all factual data supplied to 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, 2016	53	33	86	-	-	-
Extensions	-	-	-	-	-	-
Category Transfer	-	-	-	-	-	-
Technical Revisions	2	-	2	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(34)	(5)	(38)	-	-	-
Economic Factors	(1)	(21)	(23)	-	-	-
Production	(8)	-	(8)	-	-	-
December 31, 2017	13	6	19	-	-	-

	NATURAL GAS LIQUIDS			CONVENTIONAL 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, 2016	2,097	1,631	3,728	75,571	60,475	136,046	14,746	11,743	26,488
Extensions	772	600	1,372	26,135	21,697	47,832	5,128	4,216	9,344
Category Transfer	-	-	-	-	-	-	-	-	-
Technical Revisions	32	(49)	(17)	1,211	(3,172)	(1,961)	236	(578)	(341)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(9)	(1)	(10)	(429)	(59)	(488)	(114)	(16)	(129)
Economic Factors	(6)	(6)	(12)	(561)	(441)	(1002)	(100)	(101)	(201)
Production	(171)	-	(171)	(6,425)	-	(6,425)	(1,250)	-	(1,250)
December 31, 2017	2,716	2,175	4,891	95,502	78,500	174,002	18,646	15,264	33,910

As at December 31, 2017, Chinook added Extensions reserves of 5.1 MMBOE Total Proved reserves and 9.3 MMBOE Total Proved plus Probable reserves through the addition of four (3.63 net)PDP locations, six (4.6 net) PUD locations and four (3.0 net) Probable Additional locations, all in the Montney at Birley. In addition, through Technical Revisions Chinook increased its Total Proved reserves of 0.2 MMBOE and decreased its Total Proved plus Probable reserves 0.3 MMBOE. Technical revisions were the result of individual well performance changes across all principle properties. However, on a Total Proved plus Probably basis the negative technical revisions primarily related to three Birley wells completed in 2017. These negative revisions were partially offset by improved performance on immediately adjacent wells. Lastly, dispositions of 0.1 MMBOE Total Proved reserves and 0.1 MMBOE Total Proved plus Probable reserves were the result of the disposition of assets in the Gold Creek and Knopcik areas of Alberta.

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, 2017, 2016 and 2015 based on forecast prices and costs.

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2015	-	483.1	-	-	16,455.1	24,700.2	543.0	812.7
2016	-	-	-	-	19,259.8	45,457.2	558.9	1,319.0
2017	-	-	-	-	14,849.8	52,242.1	438.2	1,539.8

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2015	-	310.4	-	-	21,507.8	27,269.0	709.8	884.3
2016	-	-	-	-	20,428.4	51,765.3	555.6	1,411.1
2017	-	-	-	-	37,755.4	66,484.3	938.7	1,861.0

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**
2018	18.80	18.80
2019	42.57	42.57
2020	14.30	32.13
2021	4.43	18.67
2022	3.63	19.35
Thereafter	0.00	7.58
Total Undiscounted	83.72	139.10

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, 2017.

	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	-	-	3	1.5	1	0.4	3	2.2	1	0.4
British Columbia	10	3.6	38	4.0	134	82.2	106	66.6	99	52.6
Saskatchewan	-	-	1	0.4	-	-	1	0.4	1	0.4
Total	10	3.6	42	5.9	135	82.5	110	69.2	101	53.3

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, 2017.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	5,600	2,261	17,287	7,420	22,887	10,031
British Columbia	184,784	105,335	122,253	78,749	307,037	184,084
Saskatchewan	364	136	631	471	995	607
Manitoba	-	-	80	13	80	13
Total	190,748	108,092	140,251	86,643	330,999	194,735

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

As at the date hereof, the Corporation expects that rights to explore, develop and exploit 7,270 net acres of its undeveloped land holdings will expire by December 31, 2018. Chinook plans to drill or submit application to continue selected portions of this expiring acreage.

Forward Contracts and Marketing

The Corporation's commodity marketing strategy is to sell production in the spot market, complemented from time to time by price risk management instruments. Chinook periodically hedges the price on a portion of its crude oil and natural gas production. The following provides details of the commodity price risk management arrangements outstanding as at December 31, 2017 and as of the date hereof. As at December 31, 2017, the Corporation had not entered into any commodity price risk management arrangements. As at the date hereof, the Corporation has entered into the following commodity price risk management arrangement:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Natural gas fixed	February 1, 2018 to March 31, 2019	6,000 MMbtu/d	US$2.68/MMbtu	US$2.68/MMbtu	Chicago City Gate

As at the end of any month, if the Corporation has either up to $9.0 million or in excess of $9.0 million of net debt or draws pursuant to the Credit Facility, within 60 days of the end of any such month, the terms of the Credit Facility also require that the Corporation must enter into commodity price contracts covering no less than 30% or 50%, respectively of its forecasted twelve month combined production volumes.

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs have been estimated by McDaniel in the McDaniel Report and attributed to all properties that have been assigned reserves in the McDaniel Report and have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregated future net revenue therefrom. No allowance was made, however, for the abandonment and reclamation of any pipelines.

The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

Management estimates the costs to abandon and/or reclaim all of the Corporation's producing, shut-in and abandoned wells (consisting of 244.8 net wells), facilities and pipelines. Using public data and its experience, management estimates the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment cost history.

The following table summarizes the Corporation's estimated net cost to abandon and reclaim all existing wells and facilities as at December 31, 2017, which is expected to be incurred over an average of 25 years. In addition, the table summarizes the net cost used by McDaniel to abandon and reclaim wells and facilities as included in the estimate of future net revenue as at December 31, 2017 on a Total Proved plus Probable basis. This estimate includes the cost to abandon and reclaim all future facilities and undrilled wells that have been attributed reserves but excludes such costs where reserves have not been assigned.

As at December 31, 2017	Chinook Net Estimate to Abandon and Reclaim All Existing Wells and Facilities All Wells & Facilities (MM$)	McDaniel Net Estimate to Abandon and Reclaim Wells and Associated Facilities with Assigned Total Proved Plus Probable Reserves All Wells and Facilities (MM$)
Undiscounted, Uninflated	31.7	11.8
Undiscounted, 2% Annual Inflation	56.0	17.8
10% Discounted, Uninflated	4.7	2.3
10% Discounted, 2% Annual Inflation	6.8	3.3

The Corporation estimates that abandonment costs will approximate $0.75 million in each of the next three years. These costs relate to wells and facilities on properties that may or may not have reserves attributed to them.

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 the Corporation's property acquisition (disposition) costs, separately for proved properties and unproved properties, exploration costs and development costs for the year ended December 31, 2017:

	(M$)
Property acquisition costs	
Proved properties	-
Undeveloped properties	182
Exploration costs	200
Development costs	37,316
Corporate Acquisitions	-
Dispositions	(17,838)
Other	1,346
Total	21,206

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2017:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Oil	-	-	-	-
Heavy Oil	-	-	-	-
Natural Gas	-	-	4	3.63
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total	-	-	4	3.63

See "General Development of the Business – Recent Developments" for a description of the Corporation's 2017 exploration and development plans.

Production Estimates

The following table discloses, by product, the total volume of the Corporation's gross production estimated for the year ended December 31, 2018 as evaluated by McDaniel, which is reflected 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:	5	-	27,208	792	5,332
From Gross Probable Reserves:	-	-	773	13	142

Each of the Corporation's Birley and Martin Creek/Black-Conroy areas account for 20% or more of the Corporation's estimated 2018 production in the McDaniel Report.

Production History

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

	Quarter Ended 2017			
	December 31	**September 30**	**June 30**	**March 31**
Average Daily Sales Volumes [(1)]				
Light and Medium Crude Oil (Bbls/d)	21	19	19	29
Heavy Oil (Bbls/d)	-	-	-	-
Gas (Mcf/d)	19,240	14,109	19,065	18,022
NGLs (Bbls/d)	551	405	441	482
Combined (BOE/d)	3,779	2,776	3,638	3,514
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/Bbl)	76.96	51.49	59.55	60.33
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf) [(2)]	0.99	1.20	2.77	2.71
NGLs ($/Bbls)	51.87	42.07	44.48	51.39
Combined ($/BOE)	13.02	12.61	20.22	21.42
Royalties Paid ($/BOE) [(3)]				
Light and Medium Crude Oil ($/Bbls)	6.46	5.65	11.45	5.48
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	(0.04)	0.05	(0.13)	0.07
NGLs ($/Bbls)	1.71	(0.96)	6.35	(2.60)
Combined ($/BOE)	0.08	0.16	0.14	0.07
Operating Expenses ($/BOE) [(4)]				
Light and Medium Crude Oil ($/Bbls)	44.83	53.24	62.28	13.11
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	1.86	2.00	1.89	1.90
NGLs ($/Bbls)	9.19	12.11	12.98	10.37
Combined ($/BOE)	11.06	12.32	11.82	11.27
Netback Received ($/BOE) [(2)(5)]				
Light and Medium Crude Oil ($/Bbls)	25.67	(7.39)	(14.18)	41.73
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	(0.83)	(0.85)	1.01	0.73
NGLs ($/Bbls)	40.97	30.92	25.14	43.62
Combined ($/BOE)	1.87	0.13	8.26	10.08

Notes:

(1) Before deduction of royalties.

(2) Amounts from physical gas contracts are included in the gas prices shown.
(3) Gas cost allowance is excluded.
(4) Operating Expenses include Gathering Income and Other Income.
(5) Netbacks are calculated by subtracting royalties, and operating and transportation costs from revenues. Gas cost allowance is excluded.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2017:

Field	Light and Medium Crude Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
Birley/Umbach, British Columbia	-	10,342	295	2,019
Martin Creek/Black-Conroy, British Columbia	8	4,481	130	885
Boundary Lake, British Columbia	-	2,389	37	436
Total	8	17,212	462	3,340

The Corporation's production for the year ended December 31, 2017 was approximately less than 1% light and medium quality crude oil (32° API or greater), 86% natural gas and 14% natural gas liquids.

For the twelve months ended December 31, 2017, approximately 2% of the Corporation's commodity revenue was derived from crude oil production, 39% was derived from NGLs and 59% was derived from natural gas production.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments where the companies have assets or operations. While these regulations do not affect the Corporation's operations in any manner that is materially different than they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although governmental legislation is a matter of public record, the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

The Corporation holds interests in crude oil and natural gas properties, along with related assets, primarily in the Canadian provinces of Alberta and British Columbia. The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation. Regulated aspects of the Corporation's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable provincial regulatory scheme, producers 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 in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers, which results in the market determining the price of crude oil. Worldwide supply and demand factors primarily determine crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

The price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The price of condensate and other natural gas liquids such as ethane, butane and propane ("**NGLs**") sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

Crude oil, natural gas and NGLs exports from Canada are subject to the *National Energy Board Act* (Canada) (the "**NEB Act**") and the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the "**NEB**") is required, which is no longer the case for natural gas and NGLs. For natural gas and NGLs, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. All crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government.

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, 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 federal government.

Pursuant to the draft legislation introduced by the Government of Canada on February 8, 2018, if enacted the NEB will be replaced by the Canadian Energy Regulator ("**CER**") who will take on the NEB's responsibilities with respect to exports of crude oil, natural gas and NGL exports from Canada; however, at the present time it is not proposed that the legislative regime relating to exports of crude oil, natural gas and NGL exports from Canada will substantively change under the new regime.

The Corporation does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from western Canada to the United States and other international markets. Although certain pipeline or other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and political factors. The transportation capacity deficit is not likely to be resolved quickly given the significant length of time required to complete major pipeline or other transportation projects once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products, which may be done on a firm or interruptible basis. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in western Canada have experienced low pricing relative to other markets in the last several years. Transportation availability is highly variable across different areas and regions, which can determine the nature of transportation commitments available, the numbers of potential customers that can be reached in a cost-effective manner and the price received.

Developing a strong network of transportation infrastructure for crude oil, natural gas and NGLs, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian crude oil and natural gas industry. Improved means of access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, would help to alleviate the pressures of pricing discussed. Several proposals have been announced to increase pipeline capacity out of western Canada, to reach Eastern Canada, the United States and international markets via export shipping terminals on the west coast of Canada. While certain projects are proceeding, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the NEB and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced draft legislation to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes to the draft legislation will be made before the legislation is brought into force. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Under the terms of NAFTA, Canada remains 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 Canada 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. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

In 2017, the United States government announced its intention to renegotiate NAFTA. As a result, Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. If the United States does give notice of its intent to terminate or withdraw from NAFTA, the earliest such termination or withdrawal could occur would be six months after such notice is given. The renegotiations are still underway and the outcome of such negotiations remain unclear, but as the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, any changes to, or termination of, NAFTA could have an impact on western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The text of CPTPP has not been finalized or published and the agreement remains subject to ratification by the governments of each of the countries involved. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Land Tenure

The respective provincial governments (i.e. the Crown), predominantly own the mineral rights to crude oil and natural gas located in western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude 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. The provincial governments in western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba 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 licence. Additionally, the provinces of Alberta and British Columbia have shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba. In each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 30% and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

Royalties and Incentives

General

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 and crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights 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 substance produced.

Occasionally the governments of western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are often introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated 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. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

British Columbia

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGLs in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGLs and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGLs and condensates, the royalty rate is fixed at 20%.

The royalties payable by each producer will thus vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of 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.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which 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 applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale depending on the total number of hectares owned by the entity.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract.

In addition to the royalties payable to the mineral owners, producers of crude oil and natural gas from freehold lands in each of the western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

Regulatory Authorities and Environmental Regulation

General

The crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set 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 regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. However, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the CER. Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. It appears that additional categories of projects may be included within the new impact assessment process, such as large-scale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the public and indigenous groups prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. As to the proposed CER, many of its activities would be similar to the NEB, albeit with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The eventual effects of the proposed regulatory scheme on proponents of major projects remains unclear.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all resource development in Alberta. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. 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 a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta 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. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural 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 crude oil and natural 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 a crude oil or natural 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 Program

Alberta

The AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* (the "**OGCA**") 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 insolvent or is unable to meet its obligations. 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 to 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 assets to deemed liabilities is assessed once each month and where a security deposit is deemed to be required, the failure to post any required amounts may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis on its public website.

In *Redwater Energy Corporation (Re)* ("**Redwater**"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA, including the AB LLR Program, and the *Bankruptcy and Insolvency Act* (the "**BIA**"). This ruling meant that receivers and trustees have the right to renounce assets within insolvency proceedings, which was affirmed by a majority of the Alberta Court of Appeal. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any financial resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. This decision is currently under appeal to the Supreme Court of Canada, with final resolution expected in 2018.

In response to Redwater, the AER issued several bulletins and interim rule changes to govern while the case is appealed and to allow the Government of Alberta to develop appropriate regulatory measures to adequately address environmental liabilities. The AER's *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licence eligibility to operate wells and facilities, was amended and now requires extensive corporate governance and shareholder information, with a particular focus on any previous companies of directors and officers that have been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all are assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer, or to otherwise prove that it can satisfy its abandonment and reclamation obligations. The AER may make further rule changes in response to Redwater at any time, especially as the case heads towards a final determination, which means that additional obligations and/or different requirements may be forthcoming.

The AER has also implemented 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 is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19% of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

British Columbia

The Commission oversees a similar Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC 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 (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework. The Commission has announced that it is working to determine how best to manage risks in light of the Redwater decision, so changes may be forthcoming.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Canada.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of February 1, 2018, 174 of the 197 parties to the convention have ratified the Paris Agreement.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne, increasing annually until it reaches $50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. Four provinces currently have carbon pricing systems in place that would meet federal requirements (Alberta, British Columbia, Ontario and Quebec). The federal government will accept comments on the draft legislative proposals to implement the federal carbon pricing system until February 12, 2018.

On May 27, 2017, the federal government published draft regulations to reduce emissions of methane from the crude oil and natural gas sector. The proposed regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes, by introducing new control measures. Among other things, the proposed regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with the federal legislation. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

The *Carbon Competitiveness Incentives Regulation* (the "**CCIR**"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage 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

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. Additionally, British Columbia seeks to generate at least 93% of its electricity from clean or renewable sources and build the infrastructure necessary to transmit it. The legislation established no date for this target.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30/tonne. However, in its September update to the 2017/2018 Budget, the Government signalled raising the carbon tax to $35/tonne in April 2018.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

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

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas.

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 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 participation 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 ensure 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, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or 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.

Weakness in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and gas industry may affect the value of the Corporation's reserves, restrict its cash flow and its ability to access capital to fund the development of it properties.

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada and uncertainty and reduced confidence in the oil and natural gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, the Corporation's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due and the Corporation's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Corporation or at all. Similarly, there can be no assurance that the Corporation will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge its obligations and continue as a going concern.

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities.

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity 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; and 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 and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC and other oil and natural gas exporting nations, 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. 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 and the value 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 production, 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, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, 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.

Gathering and Processing Facilities and Pipeline Systems

Lack of capacity and/or regulatory constraints on gathering and processing facilities and pipeline systems may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas.

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. 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 and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines 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. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, operations and cash flows. Announcements and actions taken by the governments of British Columbia and Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has recently introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

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 materially adverse effect on the Corporation's ability to process its production and deliver the same for sale. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

During 2017, the majority of the Corporation's natural gas production in northeast British Columbia was subject to the AECO – BC Station 2 differential which was -$0.56/per GJ and fluctuated between -$1.61 per GJ and +$0.50 per GJ from 2010 to 2016. Going forward, exposure to the AECO – BC Station 2 differential is reduced as a result of the Corporation contracting capacity on the Alliance Pipeline effective May 1, 2016 for delivery of natural gas to the Chicago area.

The Corporation has contracted pipeline transportation capacity for approximately 20% of total forecasted natural gas sales volumes in 2018 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut-in if capacity is allocated to other parties.

Risks Relating to Indemnification Rights

The Corporation is subject to risks relating to certain obligations guaranteed in favour of the buyer in connection with the Tunisian Disposition which was completed on August 19, 2014.

The Corporation has guaranteed the payment of the indemnification obligations of Storm Ventures International (BVI) Limited ("**Storm BVI**"), a wholly-owned subsidiary of the Corporation, under a share purchase and sale agreement with the buyer dated as of June 14, 2014. These obligations relate to claims under the agreement in respect of breaches of certain representations, warranties and covenants of Storm BVI without a limit on amount or time. Consequently, any failure by Storm BVI to pay these indemnification obligations under the agreement with the buyer could result in a substantial payment by the Corporation to the buyer, which in turn could have a material adverse effect on the Corporation's working capital and financial condition. A copy of the share purchase and sale agreement is available on the Corporation's SEDAR profile.

Market Price of Common Shares

The trading price of the Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry.

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 natural gas market. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. 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 anticipated benefits of acquisitions may not be achieved and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions.

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 by third parties 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 may realize less on disposition than their carrying value on the financial statements of the Corporation.

Political Uncertainty

The Corporation's business may be adversely affected by recent political and social events and decisions made in Canada, the United States, Europe and elsewhere.

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the 2016 presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. The administration has announced withdrawal of the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces US corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. The North American Free Trade Agreement is currently under renegotiation and the result is uncertain at this time. The administration has also taken action with respect to reduction of regulation which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Corporation.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of its Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and gas industry including the balance between economic development and environmental policy such as the potential impact of the recent change of government in British Columbia and announcements and actions by the government of British Columbia that may impact the completion of the Trans-Mountain Pipeline project and other infrastructure projects.

Operational Dependence

The successful operation of a portion of the Corporation's properties is dependent on third parties.

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.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results.

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays, cost overruns and marketing challenges.

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 overruns 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, hydraulic fracturing, and waterfloods 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 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.

Competition

The Corporation competes with other oil and natural gas companies, some of which have greater financial and operational resources.

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and 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. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than 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, process, and reliability of delivery and storage.

Cost of New Technologies

The Corporation's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete.

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other 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. If the Corporation does implement such technologies, there is no assurance that the Corporation will do so successfully. 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, or is unsuccessful in implementing certain technologies, 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

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Corporation's financial condition, results of operations and cash flow.

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar affect on the demand for oil and gas products. 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 by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for oil and natural gas and/or increase the Corporation's costs and/or delay planned operations.

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. 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. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Corporation's operations, which may affect the Corporation's profitability. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*".

In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. 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, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows.

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets 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. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions – Royalties and Incentives*".

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's financial condition.

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.

Disposal of Fluids Used in Operations

Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation.

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources.

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 natural 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 compliance requirements 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.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete.

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Corporation's ability to acquire properties or require a substantial cash deposit with the regulator.

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 is unable to satisfy its regulatory obligations. These programs 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 generally required. Changes to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance obligations. In addition, the liability management regime may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and gas companies that may be disproportionately affected by price instability. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)*, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the AER to the Supreme Court of Canada for final determination. In response to the decision, the AER issued interim rules to administer the liability management program and until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Compliance with greenhouse gas emissions regulations may result in increased operational costs to the Corporation.

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with 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 UNFCCC and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. 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. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the affect of increasing the Corporation's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Corporation's financial condition.

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, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results**.**

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's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations, acquire and develop reserves.

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);
- commodity prices;
- 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. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. 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 Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. 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 may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility.

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. Failure to obtain 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. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing.

As a result of global economic and political 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. Alternatively, any available financing may be highly dilutive to existing shareholders. 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

Failing to comply with covenants under the Corporation's credit facility could result in restricted access to capital or being required to repay all amounts owing thereunder.

The Credit Facility is available at the discretion of the lender and may be demanded at any time. The amount authorized under the Credit Facility is dependent on the borrowing base determined by the lender from time to time. Notwithstanding the discretionary and demand nature of the Credit Facility, the Corporation is required to comply with covenants under the Credit Facility which include certain financial 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 ratio tests) could result in the Corporation being required to repay amounts owing thereunder. 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 imposes operating and financial restrictions on the Corporation that include restrictions on paying dividends or repurchasing or making 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 Corporation's lender uses the Corporation's reserves, commodity prices, applicable discount rates and other factors, to periodically determine the Corporation's borrowing base. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Continued depressed commodity prices or further reductions in commodity prices will likely result in a reduction to the Corporation's borrowing base, 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.

If the Corporation's lender requires repayment of all or portion of the amounts outstanding under the Credit Facility for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under the Credit Facility, 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 lender under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to it to secure the indebtedness. The Credit Facility is secured by the Corporation's consolidated assets.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise.

From time to time, the Corporation may enter into transactions to acquire assets or shares of other entities. 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

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk.

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 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

Restrictions on the availability of and access to drilling equipment may impede the Corporation's exploration and development activities.

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

Title to Assets

Defects in the title to the Corporation's properties may result in a financial loss.

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 a 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

The Corporation's estimated proved and proved plus probable reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation.

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 is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often 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

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation.

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

The principal shareholder of the Corporation will have significant influence over the business and affairs of the Corporation.

Her Majesty the Queen in Right of the Province of Alberta ("**HMQ**") owns 80,357,142 Common Shares, representing approximately 36% 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

Global political events may adversely affect commodity prices which in turn affect the Corporation's cash flow.

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, including changes in political regimes or the parties in power, 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.

Eco-Terrorism Risks

The Corporation's properties may be subject to terrorist attack.

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.

Reputational Risk Associated with the Corporation's Operations

The Corporation relies on its reputation to continue its operations and to attract and retain investors and employees.

Any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage the Corporation's reputation in the areas in which the Corporation operates. Negative sentiment towards the Corporation could result in a lack of willingness of municipal authorities being willing to grant the necessary licenses or permits for the Corporation to operate its business and in residents in the areas where the Corporation is doing business opposing further operations in the area by the Corporation. If the Corporation develops a reputation of having an unsafe work site it may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultant to operate its business. Further, the Corporation's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which the

Corporation has no control. In addition, environmental damage, loss of life, injury or damage to property caused by the Corporation's operations caused by the Corporation's operations could result in negative investor sentiment towards the Corporation, which may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Changing Investor Sentiment

Changing investor sentiment towards the oil and gas industry may impact the Corporation's access to, and cost of, capital.

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the Corporation. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Corporation, may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Dilution

The Corporation may issue additional Common Shares, diluting current Shareholders.

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 not be able to effectively manage the growth of its business.

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 or its working interest partners may fail to meet the requirements of a licence or lease, causing its termination or expiry.

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 does not pay dividends and there is no assurance that it will do so in the future.

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

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation.

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, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to 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. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on the Corporation's financial condition.

Aboriginal Claims

Aboriginal claims may adversely affect the Corporation.

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. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business and financial results.

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Corporation's competitive advantage or put it at risk of litigation.

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 generally 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

Taxation authorities may reassess the Corporation's tax returns.

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 and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and the Corporation may experience significant operational delays as a result.

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. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. 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. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Third Party Credit Risk

The Corporation is exposed to credit risk of third party operators or partners of properties in which it has an interest.

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 addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. 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. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Conflicts of Interest

Conflicts of interest may arise for the Corporation's directors and officers who are also involved with other industry participants.

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

Loss of key personnel would negatively impact the Corporation's operations.

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 personnel 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.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact its operations and financial position.

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, manage financial resources, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Expansion into New Activities

Expanding the Corporation's business exposes it to new risks and uncertainties.

The operations and expertise of the Corporation's management are currently focused primarily on oil and natural 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 condition being adversely affected.

Forward-Looking Information May Prove Inaccurate

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 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
2017			
January	0.50	0.42	6,897,443
February	0.44	0.38	5,729,468
March	0.435	0.37	5,248,661
April	0.39	0.32	4,668,536
May	0.36	0.32	7,113,186
June	0.36	0.27	2,909,404
July	0.37	0.32	4,929,765
August	0.335	0.275	1,746,884
September	0.355	0.28	3,607,270
October	0.34	0.29	1,749,598
November	0.325	0.245	3,617,540
December (1)	0.3	0.22	3,570,819

Period	High ($)	Low ($)	Volume
2018			
January	0.26	0.18	4,061,359
February	0.22	0.165	1,380,258
March (1 to 13)	0.20	0.185	516,119

Prior Sales of Outstanding Unlisted Securities

During the year ended December 31, 2017, 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 5,687,500 Common Shares at an exercise price of $0.38 per share and the grant of an aggregate of 225,000 restricted awards (entitling the holders to be issued 225,000 Common Shares as at the date of grant) 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 (2)(3) Alberta, Canada	Director	Vice President and Portfolio Manager at Matco Financial Inc. (an independent, privately held asset management firm) since October 2013 and prior thereto, independent businesswoman.
Robert J. Herdman (2) Alberta, Canada	Director	Independent businessman.
Robert J. Iverach (2)(3)(4)	Director	Counsel, Burstall Winger Zammit LLP (law firm).
P. Grant Wierzba (3)(4) Alberta, Canada	Director	Independent businessman since December 31, 2013 and prior thereto, Vice President, Operations of Chinook.
Walter J. Vrataric (4) Alberta, Canada	President and Chief Executive Officer	President and Chief Executive Officer of Chinook since December 31, 2013 and prior thereto, President of Chinook.
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 and prior thereto, Vice President, Finance and Chief Financial Officer of Zargon Oil & Gas Ltd. (oil and gas company).
Timothy S. Halpen Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Chinook.
Darrel G. Zacharias Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Chinook.
Chad T. Lerner Alberta, Canada	Vice President, Land	Vice President, Land of Chinook since June 1, 2014 and prior thereto, Senior landman of Chinook.
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. Jill T. Angevine, Robert J. Herdman, Robert J. Iverach, P. Grant Wierzba and Walter J. Vrataric have been directors of the Corporation since November 13, 2014, July 13, 2010, May 12, 2015, June 29, 2010 and May 11, 2017, respectively.
(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 4,500,764 Common Shares, being approximately 2.0% 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, 2017, 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, 2017, 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 WOGH Limited Partnership, 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, 2015, 2016 and 2017, the calculated reimbursement due to Chinook pursuant to the management and administration services agreement was approximately $1.7 million, $1.4 million and $1.0 million, respectively. AIMCo, as investment manager to HMQ, maintains control and direction over approximately 36% 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.

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 evaluator 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 McDaniel or by the "designated professionals" (as defined in Form 51-102F2 to National Instrument 51-102) of McDaniel, when McDaniel prepared the report, valuation, statement or opinion referred to herein as having been prepared by McDaniel; (ii) received by McDaniel or by the "designated professionals" of McDaniel, after the time specified above; or (iii) to be received by McDaniel or by the "designated professionals" of McDaniel; except in each case for the ownership of Common Shares, which in respect of McDaniel and McDaniel's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares.

KPMG 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.

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

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), Jill T. Angevine and Robert J. Iverach. 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.
Jill T. Angevine Calgary, Alberta	Yes	Yes	Ms. Angevine's education and experience relevant to the performance of her responsibilities as an Audit Committee member are derived from her service on boards and audit committees of numerous publicly traded oil and gas companies and her work experience analyzing oil and natural gas companies similar to our company including, most recently, as Vice President and Portfolio Manager at Matco Financial Inc. (an independent, privately held asset management firm) and prior thereto, as Vice President and Director, Institutional Research at FirstEnergy Capital Corp. (a financial advisory and investment services provider in the energy market). Ms. Angevine is a graduate of the University of Calgary, having earned a Bachelor of Commerce. She has earned the Chartered Accountant (CA) and the Chartered Financial Analyst (CFA) designations. Ms. Angevine has also completed the program offered by the Institute of Corporate Directors, including sessions devoted to audit committee functions, and is entitled to use the designation ICD.D.
Robert J. Iverach Calgary, Alberta	Yes	Yes	Mr. Iverach's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his in excess of 40 years of financial experience as a tax lawyer. Mr. Iverach has extensive experience dealing with financial statements, financial planning and tax matters pertaining to a large array of public and private corporations, partnerships, income trusts and individuals. Mr. Iverach has completed the Director Education Program offered by the Institute of Corporate Directors, including sessions devoted to audit committee functions, is entitled to use the designation "ICD.D" and has been an examiner for the program.

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, 2017	$150,000	Audit of consolidated and other financial statements
Fiscal Year Ended December 31, 2016	$842,000 (1)	Audit of consolidated and other financial statements
Audit – Related Fees		
Fiscal Year Ended December 31, 2017	$Nil	
Fiscal Year Ended December 31, 2016	$Nil	
Tax Fees		
Fiscal Year Ended December 31, 2017	$Nil	
Fiscal Year Ended December 31, 2016	$Nil	
All Other Fees		
Fiscal Year Ended December 31, 2017	$Nil	
Fiscal Year Ended December 31, 2016	$12,000	To preparation of a specified audit procedure report

Note:
(1) Amounts reflected are gross fees and do not reflect recoveries from third parties.

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 meeting of shareholders to be held on May 15, 2018. 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, 2017.

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.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is 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 evaluator;

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

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

The Reserves Committee of the Board of Directors of the 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 report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

DATED as of this 14th day of March, 2018.

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

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

(signed) "*Robert J. Iverach*"
Robert J. Iverach
Director

(signed) "*P. Grant Wierzba*"
P. Grant Wierzba
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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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 as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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 shows the net present value of 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, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management:

Independent Qualified Reserves Evaluator	Effective 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.	December 31, 2017	All of the Corporation's British Columbia and Alberta properties	-	154,207	-	154,207

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 the effective date of our report.

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 13, 2018.

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 and performance;

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.

<u>Mandate and Responsibilities of Committee</u>

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.