ANNUAL INFORMATION FORM

For the Year Ended December 31, 2019

Dated February 18, 2020

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DEFINITIONS

Capitalized terms in this annual information form ("**Annual Information Form**") have the meanings set forth below. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

"**ABCA**" means the *Business Corporations Act* (Alberta) R.S.A. 2000, c. B 9, as amended, including the regulations promulgated thereunder.

"**Arrangement**" means the arrangement involving Petrus, PhosCan, Old Petrus, Fox River and the shareholders thereof, completed pursuant to a plan of arrangement under section 193 of the ABCA.

"**Arrangement Agreement**" means the arrangement agreement dated November 29, 2015, as amended on December 15, 2015, among Petrus, Old Petrus, PhosCan and Fox River in respect of the Arrangement.

"**Board of Directors**" or "**Board**" means our board of directors.

"**Common Shares**" means our common shares, as presently constituted.

"**DSU Plan**" means the deferred share unit plan for non-management directors of Petrus dated effective October 17, 2017.

"**DSUs**" means deferred share units of the Corporation granted pursuant to the DSU Plan.

"**Fox River**" means Fox River Resources Corporation.

"**GAAP**" means generally accepted accounting principles for publicly accountable enterprises in Canada which is currently in accordance with the International Financial Reporting Standards.

"**NGP**" means Wingren B.V., a company formed under the laws of the Netherlands and a subsidiary of NGP Natural Resources X, L.P.

"**Old Petrus**" means Petrus Resources Corp., which prior to filing articles of amendment on February 2, 2016, was named "Petrus Resources Ltd.".

"**Operating Facility**" means the Petrus operating credit facility.

"**Option Plan**" means the share option plan of Petrus dated December 19, 2015.

"**Options**" means options to purchase Common Shares granted pursuant to the Option Plan.

"**Petrus**", "**we**", "**us**", "**our**" or the "**Corporation**" means Petrus Resources Ltd., a corporation incorporated under the ABCA and includes its direct and indirect subsidiaries where the context requires.

"Petrus Credit Facilities" means, collectively, the Operating Facility and Syndicated Facility.

"**Petrus Term Loan**" means the commitment letter and term sheet with an arm's length third party lender dated March 22, 2016, in respect of a committed second lien term loan.

"**PhosCan**" means Petrus Resources Inc., which prior to filing articles of amendment on February 2, 2016, was named "PhosCan Chemical Corp.".

"**Preferred Shares**" means our first preferred shares issuable in series.

"**Private Placement**" means the private placement of an aggregate of 16,217,000 Subscription Receipts at a price of $1.85 per Subscription Receipt completed on January 14, 2016.

"**RSU Plan**" means the restricted share unit plan for officers, employees and consultants of the Corporation and its subsidiaries dated October 17, 2017, as amended on March 29, 2018.

"**RSUs**" means restricted share unit awards of the Corporation granted pursuant to the RSU Plan.

"**Shareholders**" means holders of Common Shares.

"**Sproule**" means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

"**Sproule Report**" means the report prepared by Sproule dated February 18, 2020 and effective December 31, 2019 evaluating the crude oil, NGLs and natural gas and future net production revenues attributable to the properties of Petrus.

"**Syndicated Facility**" means Petrus' reserve based revolving credit facility.

"**Tax Act**" means the *Income Tax Act,* R.S.C., 1985, c. 1, as amended.

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

Selected Defined Oil and Natural Gas Terms

Certain terms used in this Annual Information Form in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this Annual Information Form, but not defined or described, are defined in NI 51-101, CSA 51-324 or the COGE Handbook (as each is defined below), as applicable and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA 51-324 or the COGE Handbook, as applicable.

"**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.

"**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

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

"**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 (e.g., when compared to the cost of drilling a well) to put the reserves on production.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; or

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a).

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs.

"**gross**" means:

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

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

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

"**hydrocarbon**" means a compound consisting of hydrogen and carbon, which, when naturally occurring, may also contain other elements such as sulphur.

"**light crude oil**" means crude oil with a relative density greater than 28° API.

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases.

"**natural gas liquids**" or "**NGLs**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

"**net**" means:

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

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

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

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

"**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.

"**property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer). A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**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.

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

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

"**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: (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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, possible) 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 sub-divide 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.

"**working interest**" means the percentage of undivided interest held by Petrus in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives Petrus the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

ABBREVIATIONS AND CONVERSIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
Bbls/d	barrels per day	MMcf/d	million cubic feet per day
NGLs	natural gas liquids	MMBtu	million British Thermal Units

Other Abbreviations:

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas
BOE/d	barrel of oil equivalent per day
MBOE	1,000 barrels of oil equivalent
MMBOE	1,000,000 barrels of oil equivalent
m3	cubic metres
$000s or M$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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

To Convert From	To	Multiply By
Mcf	Cubic metres	0.28174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of our natural gas and petroleum reserves does not represent the fair market value of our reserves.

Caution Respecting BOE

In this Annual Information Form, the abbreviation BOE means barrel of oil equivalent on the basis of 1 Bbl to 6 Mcf of natural gas when converting natural gas to BOEs. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 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 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 Mcf to 1 Bbl, utilizing a conversion ratio at 6 Mcf to 1 Bbl may be misleading as an indication of value.**

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that such expectations will prove to be correct and the forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These forward-looking statements speak only as of the date of this Annual Information Form.

More particularly, this Annual Information Form contains forward-looking statements with respect to:

- Petrus' corporate strategy;
- the timing and impact of the Foothills Disposition;
- planned capital expenditures and drilling activity in 2020;
- development plans for our proved and probable undeveloped reserves;
- plans for funding future development costs including the timing of future development projects;
- plans for debt repayment and the timing thereof;
- Petrus' dividend policy;
- anticipated timing of expenditures by us to satisfy our asset retirement obligations;
- anticipated impact of environmental laws and regulations on our business;
- anticipated land expiries;
- anticipated future abandonment and reclamation costs;
- expectations of the means of funding our ongoing environmental obligations;
- waterflood expansion opportunities;
- drilling inventories; and
- the anticipated impact of the factors discussed under the heading "*Industry Conditions*" on the Corporation.

These forward-looking statements are based on certain key expectations and assumptions made by us, including, but not limited to:

- the performance characteristics of our assets;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;

- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- prevailing weather conditions, commodity prices and exchange rates;
- drilling plans;
- availability of labour, services and equipment;
- timing and amount of capital expenditures;
- future abandonment and reclamation costs;
- general economic and financial market conditions;
- tax horizons;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- the success of our exploration and development activities;
- current commodity prices and royalty regimes;
- timing and amount of capital expenditures;
- future exchange rates;
- the impact of increasing competition;
- future operating costs;
- that the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed;
- that the Corporation's conduct and results of operations will be consistent with its expectations;
- that the Corporation will have the ability to develop the Corporation's oil and natural gas properties in the manner currently contemplated;
- that current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and
- that the estimates of the Corporation's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects.

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 can be profitably produced in the future.

The actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to:

- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- inability to secure labour, services and equipment on a timely basis or favourable terms;
- competition for, among other things, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- geological, technical, drilling, production and processing problems;
- availability and cost of capital;
- changes in legislation, including changes in tax laws, royalty rates and incentive programs relating to the oil and natural gas industry; and
- the other factors discussed under *Risk Factors*.

Although the forward-looking statements contained in this Annual Information Form are based upon assumptions which Petrus believes to be reasonable, Petrus cannot assure readers that actual results will be consistent with these forward-looking statements.

Petrus has included the above summary of assumptions and risks related to forward-looking information provided in this Annual Information Form in order to provide readers with a more complete perspective on the Corporation's current and future operations and such information may not be appropriate for other purposes. The Corporation's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Petrus will derive therefrom.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

NON-GAAP MEASURES

This Annual Information Form contains the term "operating netback". This indicator is not a recognized measure under GAAP and does not have a standardized meaning prescribed by GAAP.

We use operating netback to analyze our financial and operating performance and believe this measure provides useful supplemental information enabling us to analyze operating performance and provides an indication of the results generated by the Corporation's principal business activities. We feel this benchmark is a key measure of Petrus' profitability and overall sustainability. Readers should be cautioned that this measure is not intended to represent operating profits and should not be construed as an alternative to cash flows from operating activities, net income (loss) or other measures of financial performance as determined in accordance with GAAP. Petrus' method of calculating this measure may differ from other companies, and accordingly, it may not be comparable to similar measures used by other companies. For more information, including a reconciliation of operating netback to the applicable GAAP measures, please see our Management's Discussion and Analysis for the year ended December 31, 2020, a copy of which has been filed on our SEDAR profile at *www.sedar.com*.

Operating netback is a common non-GAAP financial measure used in the oil and natural gas industry which is a useful supplemental measure to evaluate the specific operating performance by product at the oil and gas lease level. The operating netback is calculated as oil and natural gas realized revenue (price) less royalties, operating and transportation expenses. It is presented on an absolute value and per unit of production basis.

CORPORATE STRUCTURE

General

Petrus was incorporated pursuant to the ABCA on November 25, 2015 as "Petrus Acquisition Corp.", for the sole purpose of participating in the Arrangement and the Private Placement. On February 2, 2016, pursuant to the Arrangement, Petrus filed articles of amendment to change its name to "Petrus Resources Ltd.". See "*Development of Our Business*".

Our head office is located at 2400, 240 – 4th Avenue S.W., Calgary, Alberta and our registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta. We are a reporting issuer in each of the provinces of British Columbia, Alberta and Ontario.

Inter-corporate Relationships

Petrus has two wholly owned subsidiaries, Old Petrus and PhosCan. Old Petrus is a corporation existing under the laws of Alberta. Phoscan is a corporation that was incorporated under the federal laws of Canada and, pursuant to the Arrangement, was continued to and currently exists under the laws of Alberta.

DEVELOPMENT OF OUR BUSINESS

The following is a summary of the developments of the business of Petrus over the last three completed financial years.

2017

Overview of Capital Expenditure Program

During the financial year ended December 31, 2017, Petrus invested $72.8 million to drill 19 gross (13.2 net) wells and for construction costs related to facilities and pipeline infrastructure in the Ferrier/Strachan area of Alberta. Average production for the year ended December 31, 2017 was 10,217 BOE/d (29% oil and natural gas liquids).

General Business Development

In January 2017, the Board of Directors approved a $50 to $60 million capital budget for 2017, primarily directed at the development of Petrus' Ferrier assets.

On January 24, 2017, Petrus entered into an agreement to extend the Petrus Term Loan by two years to October 8, 2019. Concurrent with the extension, Petrus reduced the amount outstanding under the Petrus Term Loan by $7 million to $35 million.

On February 28, 2017, Petrus completed the acquisition, from a private company, of certain oil and natural gas interests in the Ferrier area of Alberta (the "**2017 Ferrier Acquisition**") for cash consideration of $8.9 million net of closing adjustments.

Also on February 28, 2017, the Corporation closed a private placement of Common Shares at a price of $2.53 per Common Share for aggregate gross proceeds of $10.3 million. A portion of the net proceeds of the private placement were used to fund the 2017 Ferrier Acquisition and the remainder were used to fund Petrus' 2017 capital program.

On August 15, 2017, Petrus closed the disposition of its working interest in certain non-core oil and natural gas properties in the Foothills area of Alberta for cash consideration of $4.9 million. The assets disposed of included approximately 150 BOE/d of production along with related land and infrastructure. The proceeds were utilized to repay indebtedness under the Petrus Credit Facilities.

In October 2017, Petrus entered into a farm-in agreement to drill two extended reach horizontal Cardium wells in Ferrier. In order to accommodate for the farm-in agreement, the Board of Directors approved a $10 million increase to Petrus' capital budget for 2017 to $60 to $70 million.

In October 2017, Petrus completed its semi-annual review of the Syndicated Facility. The syndicate of lenders under the Syndicated Facility, increased the borrowing base under the Petrus Credit Facilities from $120 million to $130 million. In addition, the Petrus' total debt borrowing limit was increased from $141 million to $155 million.

In December 2017, the Board of Directors approved a $25 to $30 million capital budget for 2018, primarily directed at the development of Petrus' Ferrier assets.

2018

Overview of Capital Expenditure Program

During the financial year ended December 31, 2018, Petrus invested $24.0 million to drill 10 gross (4.3 net) wells in the Ferrier/Strachan area of Alberta. Average production for the year ended December 31, 2018 was 9,019 BOE/d (31% oil and natural gas liquids).

General Business Development

In May 2018, Petrus entered into an agreement with the lender under the Petrus Term Loan to extend the maturity date of the Petrus Term Loan from October 8, 2019 to October 8, 2020. At that time, Petrus also completed its semi-annual review of the Syndicated Facility. The syndicate of lenders under the Syndicated Facility agreed to maintain the borrowing base of $120 million until June 30, 2018 after which time it was decreased to $110 million. Petrus' total debt borrowing limit was reduced to $140 million, effective June 30, 2018.

In October 2018, Petrus completed its semi-annual review of the Syndicated Facility. The syndicate of lenders under the Syndicated Facility maintained the borrowing base under the Petrus Credit Facilities at $110 million. Petrus' total debt borrowing limit was also maintained at $140 million.

2019

Overview of Capital Expenditure Program

During the financial year ended December 31, 2019, Petrus invested $18.0 million to drill 10 gross (3.1 net) wells in the Ferrier/Strachan area of Alberta. Average production for the year ended December 31, 2019 was 8,306 BOE/d (36% oil and natural gas liquids).

General Business Development

In May 2019, Petrus completed its annual review of the Syndicated Facility. The syndicate of lenders reduced the borrowing base under the Petrus Credit Facilities to $100 million. The revolving period was extended to May 31, 2020 and the maturity date for repayment of the Syndicated Facility was set to May 31, 2020. Borrowings under the Syndicated Facility above $95 million require consent from each of the syndicate of lenders.

On September 5, 2019, the Corporation disposed of certain exploration and evaluation assets for $0.7 million.

In November 2019, Petrus completed its semi-annual review of the Syndicated Facility. The syndicate of lenders agreed to maintain the borrowing base under the Petrus Credit Facilities at $100 million. Borrowings under the Syndicated Facilities above $93 million require consent from each of the syndicate of lenders as of December 31, 2019.

On December 9, 2019, Petrus entered into an agreement for the sale of its oil and natural gas interests in the Foothills area of Alberta to an arm's length private company for total consideration of $1.8 million, subject to customary closing conditions and adjustments (the "**Foothills Disposition**"). At December 31, 2019, Petrus' Foothills assets contributed 5% and 13% of the Corporation's Total Proved and Total Proved plus Probable reserve volumes, respectively.

Recent Developments

In January 2020, the Board of Directors approved a first quarter 2020 capital budget of $9 million, focused on drilling opportunities in the Corporation's inventory at Ferrier, Alberta. The Corporation plans to drill throughout 2020 within funds flow and repay $1 to $2 million of debt each quarter.

Significant Acquisitions

Petrus 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 OUR BUSINESS

Corporate Strategy

Petrus is a Canadian oil and natural gas company focused on property exploitation and strategic acquisitions in Alberta. Through a combination of acquisitions and drilling, our production has grown to an annual average of 8,306 BOE/d as of December 31, 2019.

Our current areas of operation are in all season access lands with significant infrastructure in the Ferrier/Strachan and Thorsby/Pembina areas of Alberta. Management believes these properties provide a sustainable platform of low decline oil and natural gas production, along with a multi-year inventory of drilling locations that includes light oil and liquids rich natural gas locations which management believes are economic in today's commodity price environment. See "*Principal Properties*".

On January 14, 2020, Petrus announced its planned capital expenditure budget of $9 million (excluding acquisitions and dispositions) for the first quarter of 2020 which is primarily focused on the highest rates of return, lowest risk, condensate rich drilling opportunities in the Corporation's inventory at Ferrier, Alberta. The objectives of the 2020 capital plan are to invest capital systematically each quarter within funds flow, permitting excess funds each quarter to reduce debt. See "*Development of Our Business – 2020 – Overview of Capital Expenditure Program*".

The Board of Directors may, in its discretion, approve asset or corporate acquisitions or investments based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life, strategic importance and asset quality. See "*Industry Conditions*" and "*Risk Factors – Failure to Realize Anticipated Benefits of Acquisitions and Dispositions*".

Specialized Skill and Knowledge

Petrus employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, engineering, financial, geology, geophysics and business skills, which are widely available in the industry. Drawing on significant experience in the oil and natural gas business, Petrus believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Petrus to effectively identify, evaluate and execute on its business plan.

Competitive Conditions

The oil and natural gas industry is competitive in all its phases. We compete with numerous other participants in the acquisition, exploration and development of oil and natural gas assets and in the marketing of oil and natural gas. Our competitors include resource companies which may have greater financial resources, staff and facilities than us. We believe that our competitive position is, on the whole, equivalent to that of other oil and natural gas producers of similar size and at a similar stage of development. See "*Industry Conditions*" and "*Risk Factors – Competition*".

Environmental Policies

We promote safety and environmental awareness and protection through the implementation and communication of our environmental management and employee occupational health and safety programs, policies and procedures. Committee structures are established in our operations which are designed to allow for employee participation and development of policies and programs which provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

We have developed emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which we operate in order to effectively respond to an environmental incident should it arise. Environmental assessments are undertaken for new projects, or when acquiring new properties or facilities, in order to identify, assess and minimize environmental risks and operational exposures. We periodically conduct reviews of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability to assist in achieving the objectives of the described policies and programs.

We also face environmental, health and safety risks in the normal course of our operations due to the handling and storage of hazardous substances. Our environmental and occupational health and safety management systems are designed to manage such risks and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety reviews. See "*Industry Conditions*" and "*Risk Factors - Environmental"*.

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. Unexpected adverse weather conditions, such as flooding or prolonged break-up, can have a significant negative impact on our operations and costs. See "*Industry Conditions*" and "*Risk Factors - Availability of Drilling Equipment and Access*".

Personnel

As at December 31, 2019, Petrus had 15 full-time employees, one part-time employee and 16 consultants under contract.

PRINCIPAL PROPERTIES

Ferrier/Strachan Area – West Central Alberta

The Ferrier/Strachan area is Petrus' principal property and is located in west central Alberta near the town of Rocky Mountain House, Alberta. Petrus currently holds an average 54% working interest in 78,785 gross (42,562 net) acres of land in the Ferrier/Strachan area, of which 49,219 gross (28,931 net) acres are undeveloped and 29,566 gross (13,631 net) acres are developed. Petrus acquired the assets in the Ferrier/Strachan area through a combination of corporate and asset acquisitions, farm-in agreements with joint venture partners. Exploration, development and production activities in the Ferrier/Strachan area are primarily directed toward oil, natural gas and natural gas liquids in the Cardium formation.

Sproule assigned approximately 21,492 MBOE of proved reserves and 32,397 MBOE of proved plus probable reserves to the Ferrier/Strachan area in the Sproule Report. During the year ended December 31, 2019, the Ferrier/Strachan area provided Petrus with average production of approximately 6,284 BOE/d (including 2,266 Bbls/d of oil and natural gas liquids and 24,110 Mcf/d of natural gas) from 105 gross (57.8 net) producing wells. As at December 31, 2019, we operated approximately 90% of our production in the Ferrier/Strachan area. The majority of Petrus' Ferrier/Strachan production is pipeline connected to its owned and operated gas plant. Natural gas and natural gas liquids are either processed at a third party gas plant, or at Petrus' processing facility and gas plant, both of which are pipeline connected to a sales point.

Petrus invested approximately $18 million in the Ferrier/Strachan area in the year ended December 31, 2019. 10 gross (3.1 net) wells were drilled in the year ended December 31, 2019 and 10 gross (3.1 net) were on production by year-end. The majority of the capital invested at Ferrier/Strachan during 2019 was directed towards drilling, completion, tie-in and equipping of the new wells in addition to investment in the expansion of Ferrier production processing infrastructure.

In addition to its core property in the Ferrier/Strachan area of Alberta, Petrus also has two non-core properties located in Alberta. These properties are described below.

Thorsby/Pembina Area – Central Alberta

The Thorsby/Pembina area of central Alberta is located approximately 70 kilometers southwest of Edmonton, Alberta. Petrus currently holds an average 63% working interest in 112,137 gross (70,644 net) acres of land in the Thorsby/Pembina area, of which 39,060 gross (23,719 net) acres are undeveloped and 73,077 gross (46,925 net) acres are developed. Petrus acquired its assets in the central Alberta area through a corporate acquisition. Our exploration, development and production activities in the Thorsby/Pembina area are primarily directed towards light oil in the Glauconite formation.

Sproule assigned approximately 4,238 MBOE of proved reserves and 7,866 MBOE of proved plus probable reserves in Central Alberta in the Sproule Report. During the year ended December 31, 2019, Petrus had average production of approximately 1,585 BOE/d (including 556 Bbls/d of oil and liquids and 6,173 Mcf/d of natural gas) from 120 gross (91.7 net) producing wells in the central Alberta area. As at December 31, 2019, we operated approximately 95% of the production in the Thorsby/Pembina area. Substantially all of our production in the area is pipeline connected to owned and operated oil batteries and gas plants. Clean oil and natural gas is transferred directly to sales pipelines once processed at an oil battery.

Petrus did not invest significant capital in this area in 2019.

Foothills Area – West Central Alberta

The Foothills area is located in a trend from approximately 75 km northwest of Rocky Mountain House, Alberta to approximately 75 km northwest of Hinton, Alberta. Petrus currently holds an average 50% working interest in 77,799 gross (38,935 net) acres of land in the Foothills area, of which 56,359 gross (32,088 net) acres are undeveloped and 21,440 gross (6,847 net) acres are developed. Petrus has wells producing from the Cardium, Charlie Lake, Montney, Leduc, Dunvegan and Notikewin formations, as well as other formations. The properties located in the northern section of the Foothills area feature a predominantly mature production base with a stable production decline and reserve bookings. The properties located in the southern Foothills area include Brown Creek and Cordel/Stolberg, where we have focused the majority of our Foothills development to date. Petrus acquired its Foothills assets through a combination of asset acquisitions and farm-ins. Petrus currently operates 23% of its Foothills production and has a working interest in a variety of compressor stations, gas plants and pipeline infrastructure.

Sproule assigned approximately 4,476 MBOE of proved reserves and 6,639 MBOE of proved plus probable reserves to the Foothills area in the Sproule Report. During the year ended December 31, 2019, the Foothills area provided Petrus with average production of approximately 438 BOE/d (including 145 Bbls/d of oil and natural gas liquids and 1,749 Mcf/d of natural gas) from 59 gross (17.4 net) producing wells. Substantially all of our Foothills natural gas production is pipeline connected. Natural gas and natural gas liquids are processed at jointly owned and third party gas plants and then go directly to sales. The majority of our Foothills light oil production is pipeline connected to satellite oil batteries; clean oil is trucked directly to sale terminals once processed at the respective oil battery.

Petrus did not invest significant capital in this area in 2019. On December 9, 2019, Petrus entered into an agreement providing for the Foothills Disposition. The Foothills Disposition has an effective date of November 1, 2019 and is expected to close in the first quarter of 2020. At December 31, 2019, Petrus' Foothills assets contributed 5% and 13% of the Company's Total Proved and Total Proved plus Probable reserve volumes, respectively.

STATEMENT OF RESERVES DATA

The report of Sproule in Form 51-101F2 and the report of management and directors on oil and natural gas disclosure in Form 51-101F3 and the report on reserves data by are attached as Schedules "B" and "C" to this Annual Information Form, respectively.

Disclosure of Reserves Data

The statement of reserves data and other oil and natural gas information set forth below (the "**Reserves Data**") is based upon an evaluation by Sproule with an effective date of December 31, 2019, contained in the Sproule Report, which has a preparation date of February 18, 2020. The Sproule Report evaluated, as at December 31, 2019, the crude oil, NGLs and natural gas reserves of Petrus. The Reserves Data summarizes Petrus' crude oil, NGLs and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs.

The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Corporation believes is important to readers of this Annual Information Form. Sproule was engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The Sproule Report is based on certain factual data supplied by us and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by us to Sproule. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

The net present value of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment and reclamation costs.

Petrus determined the future net revenue and present value of future net revenue after income tax expenses by utilizing Sproule's before income tax future net revenue and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and natural gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of Petrus as a business entity, which may be significantly different. Our financial statements for the year ended December 31, 2019 should be consulted for additional information regarding our taxes.

All of Petrus' consolidated reserves are in Canada and, specifically, in the Province of Alberta.

There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and natural gas reserves and the future cash flows attributed to such reserves. In general, such estimates are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGL 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 consolidated reserves will vary from estimates thereof and such variations could be material.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The information relating to the Corporation's consolidated crude oil, NGLs and natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans, timing and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "*Special Note Regarding Forward-Looking Statements*", "*Industry Conditions*" and "*Risk Factors*".

In certain of the tables set forth below, the columns may not add due to rounding.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

	RESERVES									
	GROSS RESERVES					NET RESERVES				
RESERVE CATEGORY	Light and Medium Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane Gas (MMcf)	Total BOE (MBOE)	Light and Medium Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane Gas (MMcf)	Total BOE (MBOE)
PROVED:										
Developed Producing	1,248.4	2,722.8	46,105.0	Nil	11,655.3	1,099.0	2,078.5	40,989	Nil	10,008.9
Developed Non-Producing	5.0	90.7	18,202	Nil	3,129.3	5.0	64.8	15,721	Nil	2,689.9
Undeveloped	1,259.9	4,762.6	56,397	Nil	15,421.9	1,081.5	4,062.8	50,577	Nil	13,573.9
TOTAL PROVED	2,513.2	7,576.1	120,703	Nil	30,206.6	2,185.5	6,206.1	107,287	Nil	26,272.7
PROBABLE	2,476.9	3,773.4	62,672	Nil	16,695.7	2,091.0	3,056.2	57,185	Nil	14,678.0
TOTAL PROVED PLUS PROBABLE	4,990.1	11,349.5	183,376	Nil	46,902.3	4,276.5	9,262.3	164,472	Nil	40,950.8

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)					
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year[(1)] ($/BOE)
PROVED:						
Developed Producing	143,061	151,543	138,707	124,713	112,790	13.86
Developed Non-Producing	15,255	11,428	9,032	7,405	6,232	3.36
Undeveloped	204,442	138,197	95,400	66,557	46,336	7.03
TOTAL PROVED	362,758	301,168	243,140	198,676	165,358	9.25
PROBABLE	306,799	207,302	149,307	112,327	87,143	10.17
TOTAL PROVED PLUS PROBABLE	669,557	508,470	392,446	311,003	252,501	9.58

Note:
(1) Unit values based on net volumes.

	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	143,061	151,543	138,707	124,713	112,790
Developed Non-Producing	15,255	11,428	9,032	7,405	6,232
Undeveloped	204,442	138,197	95,400	66,557	46,336
TOTAL PROVED	362,758	301,168	243,140	198,676	165,358
PROBABLE	250,756	173,580	128,018	98,342	77,646
TOTAL PROVED PLUS PROBABLE	613,515	474,748	371,158	297,018	243,004

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS [(1)(2)]

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES ($000s)	INCOME TAX EXPENSES ($000s)	FUTURE NET REVENUE AFTER INCOME TAX EXPENSES ($000s)
Total Proved	1,072,589	124,524	334,779	174,027	76,500	362,758	Nil	362,758
Total Proved plus Probable	1,744,872	208,593	517,097	267,652	81,973	669,557	56,042	613,515

Notes:

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

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE[1] ($/Boe)
Proved	Light and Medium Crude Oil [2]	67,432	15.78
	Conventional Natural Gas [3]	175,707	7.99
	Coalbed Methane [3]	-	-
	Total	243,140	
Proved plus Probable	Light and Medium Crude Oil [2]	118,964	14.91
	Conventional Natural Gas [3]	273,483	8.29
	Coalbed Methane [3]	-	-
	Total	392,446	

Notes:

(1) Unit values are based on net reserve volumes.
(2) Including solution gas and other by-products.
(3) Including by-products but excluding solution gas and by-products from oil wells.

Pricing Assumptions – Forecast Prices and Costs

Weighted average historical prices we realized for the year ended December 31, 2019, excluding price risk management activities, were $64.11/Bbl for light and medium crude oil, $1.89/Mcf for conventional natural gas and $22.13 /Bbl for NGLs. Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2019 in the Sproule Report in estimating reserves data using forecast prices and costs as shown in the table below.

SUMMARY OF WEIGHTED AVERAGE HISTORICAL PRICES FOR 2019 AND PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS (1)

	MEDIUM AND LIGHT CRUDE OIL		NATURAL GAS	NATURAL GAS LIQUIDS			
YEAR	Canadian Light Sweet Crude 40° API ($/Bbl)	Western Canada Select 20.5° API ($/Bbl)	Alberta AECO-C Spot ($/MMBtu)	Edmonton Propane ($/Bbl)	Edmonton Butane ($/Bbl)	Edmonton Condensate ($/Bbl)	Exchange Rate ($US/$Cdn) (2)
2019 Actual Benchmarks(1)	68.87	58.77	1.80	17.16	23.71	71.39	0.75
Forecast Benchmarks							
2020	73.84	59.81	2.04	25.07	37.72	76.32	0.76
2021	78.51	63.98	2.27	31.84	43.90	80.52	0.77
2022	78.73	63.77	2.81	32.43	47.74	80.00	0.80
2023	80.30	65.04	2.89	33.26	48.69	81.68	0.80
2024	81.91	66.34	2.98	34.12	49.67	83.38	0.80
2025	83.54	67.67	3.06	34.99	50.66	85.13	0.80
2026	85.21	69.02	3.15	35.88	51.67	86.90	0.80
2027	86.92	70.40	3.24	36.78	52.71	88.72	0.80
2028	88.66	71.81	3.33	37.71	53.76	90.57	0.80
2029	90.43	73.25	3.42	38.65	54.84	92.45	0.80
2030	92.24	74.71	3.51	39.61	55.93	94.38	0.80
Escalated at 2.0% per year thereafter							

Notes:

(1) As at December 31, 2019.
(2) Exchange rate used to generate the benchmark reference prices in this table.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of our gross reserves as at December 31, 2019, derived from the Sproule Report using forecast prices and cost estimates, reconciled to our gross reserves as at December 31, 2018.

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

PROVED RESERVES	LIGHT AND MEDIUM CRUDE OIL (Mbbls)	NATURAL GAS LIQUIDS (Mbbls)	CONVENTIONAL NATURAL GAS (MMcf)	COALBED METHANE (MMcf)	TOTAL OIL EQUIVALENT (MBOE)
December 31, 2018	2,817.7	8,390.7	126,650	Nil	32,316.8
Extensions	Nil	Nil	Nil	Nil	Nil
Infills	37.4	10.5	197	Nil	80.8
Improved Recovery	Nil	Nil	Nil	Nil	Nil
Technical Revisions (1)	383.1	(202.9)	8,887	54	1,670.4
Discoveries	Nil	Nil	Nil	Nil	Nil
Acquisitions (3)	Nil	Nil	Nil	Nil	Nil
Dispositions (3)	Nil	Nil	Nil	Nil	Nil
Economic Factors (2)	(138.3)	(126.7)	(3,439)	Nil	(838.1)
Production	(586.7)	(495.5)	(11,592)	(54)	(3,023.3)
December 31, 2019	2,513.2	7,576.1	120,703	Nil	30,206.6

PROBABLE RESERVES	LIGHT AND MEDIUM CRUDE OIL	NATURAL GAS LIQUIDS	CONVENTIONAL NATURAL GAS	COALBED METHANE	TOTAL OIL EQUIVALENT
	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
December 31, 2018	2,518.8	4,319.7	65,072	Nil	17,684.1
Extensions	Nil	Nil	Nil	Nil	Nil
Infills	6.0	2.0	38	Nil	14.3
Improved Recovery	Nil	Nil	Nil	Nil	Nil
Technical Revisions (1)	(96.8)	(517.4)	(1,402)	Nil	(848.1)
Discoveries	Nil	Nil	Nil	Nil	Nil
Acquisitions (3)	Nil	Nil	Nil	Nil	Nil
Dispositions (3)	Nil	Nil	Nil	Nil	Nil
Economic Factors (2)	48.9	(30.9)	(1,035)	Nil	(154.5)
Production	Nil	Nil	Nil	Nil	Nil
December 31, 2019	2,476.9	3,773.4	62,673	Nil	16,695.7

PROVED PLUS PROBABLE RESERVES	LIGHT AND MEDIUM CRUDE OIL	NATURAL GAS LIQUIDS	CONVENTIONAL NATURAL GAS	COALBED METHANE	TOTAL OIL EQUIVALENT
	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
December 31, 2018	5,336.5	12,710.4	191,723	Nil	50,000.8
Extensions	Nil	Nil	Nil	Nil	Nil
Infills	43.4	12.5	235	Nil	95.1
Improved Recovery	Nil	Nil	Nil	Nil	Nil
Technical Revisions (1)	286.3	(720.3)	7,483	54	822.3
Discoveries	Nil	Nil	Nil	Nil	Nil
Acquisitions (3)	Nil	Nil	Nil	Nil	Nil
Dispositions (3)	Nil	Nil	Nil	Nil	Nil
Economic Factors (2)	(89.4)	(157.6)	(4,473)	Nil	(992.5)
Production	(586.7)	(495.5)	(11,592)	(54)	(3,023.3)
December 31, 2019	4,990.1	11,349.5	183,376	Nil	46,902.3

Notes:

(1) Includes technical revisions due to reservoir performance, geological and engineering changes as well as changes of category from probable to proven.
(2) Includes economic revisions due to changes in economic limits and related to price and royalty factor changes.
(3) Includes production attributable to any acquired interests from the acquisition date to effective date of the report and production realized from disposed interests from the opening balance date to the effective date of disposition.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proven undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. Probable undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

Petrus currently plans to pursue the development of our proved and probable undeveloped reserves within the next four years through ordinary course capital expenditures. In some cases, it will take longer than four years to develop these reserves due; however, Petrus expects that the large majority of our booked undeveloped projects will be completed within a three year time frame. The timing of the development of such projects is guided by, among other things, capital constraints and yearly budgeting. There are a number of factors that could result in delayed or cancelled development, including the following: (i) existence of higher priority expenditures; (ii) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (iii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iv) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (v) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (vi) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). See "*Risk Factors – Reserve Estimates*".

Proved Undeveloped Reserves

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

Year	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		Coalbed Methane (MMcf)		NGLs (Mbbls)	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2017	0.0	1,674.7	5,803	55,193	-	-	365.6	2,942.2
2018	11.7	1,474.4	4,996	57,180	-	-	525.0	4,882.4
2019	0.0	1,259.9	0.0	56,397	-	-	-	4,762.6

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. Sproule has assigned 15,422 MBOE of proved undeveloped reserves in the Sproule Report with $172.5 million of associated undiscounted capital, of which $161.8 million is forecast to be spent in the first three years.

Probable Undeveloped Reserves

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

Year	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		Coalbed Methane (MMcf)		NGLs (Mbbls)	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2017	0.0	2,366.6	11,892	44,682	-	-	749.2	2,155.1
2018	3.0	2,068.0	2,886	45,082	-	-	303.8	3,383.1
2019`	0.0	2,020.5	0.0	44,838	-	-	0.0	3,047.1

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. Sproule has assigned 16,696 MBOE of probable undeveloped reserves in the Sproule Report with $93.6 million of associated undiscounted capital, of which $84.3 million is forecast to be spent in the first three years.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in future commodity prices relative to the forecasts provided under "*Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above, we expect to fund the development costs of our reserves through a combination of cash flow from operating activities, availability under the Petrus Credit Facilities and/or and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves could have a negative impact on our future cash flows from operating activities. Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

The Foothills Disposition has an effective date of November 1, 2019 and is expected to close in the first quarter of 2020. At December 31, 2019, Petrus' Foothills assets contributed 5% and 13% of the Company's Total Proved and Total Proved plus Probable reserve volumes, respectively.

Abandonment and Reclamation Costs

Abandonment and reclamation costs for all existing wells and facilities (i.e. producing, standing, injection etc.) have been forecast by Petrus at the corporate level and abandonment and reclamation costs for the future proposed development wells have been forecast by Sproule as part of the Sproule Report. These abandonment and reclamation costs have been estimated in the Sproule Report and attributed to all properties that have been assigned reserves in the Sproule Report and have been taken into account by Sproule in determining reserves that should be attributed to a property and in determining the aggregated future net revenue therefrom.

Petrus 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.

No estimate of salvage value is netted against the estimated cost. Our model for estimating the amount of future abandonment and reclamation expenditures was done on an individual well and facility level. Estimated expenditures are based on internal estimates using current regulatory standards and actual abandonment cost history. Each well and facility are assigned an average cost (by commodity type and well depth) for abandonment and reclamation over the estimated lives of the assets. Facility reclamation costs are generally scheduled to begin shortly before the end of the reserve life of our associated reserves and continue beyond the reserve life under the assumption that decommissioning of facilities are generally mobile assets with a long useful life.

We estimate that we will incur total net reclamation and abandonment costs of $8.9 million, discounted at 10%, to abandon and reclaim all wells and facilities ($41.4 million undiscounted, before tax). Abandonment and reclamation costs undiscounted and expected to be paid over the next three years totals approximately $1.8 million.

Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities and leases) can be found in Petrus' audited financial statements for the year ended December 31, 2019 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the Sproule Report of future net revenue attributable to our proved reserves and proved plus probable reserves (using forecast prices and costs).

Year	FORECAST PRICES AND COSTS Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2020	41,019	54,452
2021	72,106	135,558
2022	50,186	57,561
2023	5,782	15,147
2024	4,934	4,934
TOTAL UNDISCOUNTED	174,027	267,652

We have several different sources of funding to consider in order for financing future development costs: internally generated cash flows from operating activities, debt financing, equity financing and asset dispositions. We currently expect to fund future development costs primarily through cash flows from operating activities. We may rely, to some extent, on debt financing by utilizing the available Petrus Credit Facilities or on equity financing by issuing additional Common Shares. The use of debt or equity financing would be dependent on market conditions, the cost of the capital, the desirability of accelerating our capital expenditure program and the availability of financing on favourable terms. The use of proceeds from asset dispositions would be dependent on prevailing commodity and market conditions which impact the ability to dispose of properties on favourable terms.

OTHER OIL AND NATURAL GAS INFORMATION

Oil and Natural Gas Wells

The following table sets forth the number and status of our wells effective December 31, 2019.

	PRODUCING WELLS				NON-PRODUCING WELLS					
	Oil		Natural Gas		Oil		Natural Gas		Other Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	121	66.7	163	100.2	166	73.0	238	143.9	32	14.4
TOTAL	121	66.7	163	100.2	166	73.0	238	143.9	32	14.4

Notes:

"Gross" wells means the number of wells in which the Corporation has a working interest.
"Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Corporation's percentage working interest therein.
Other Non-producing includes wellbores shut-in for economic reasons, wellbores not capable of production and wellbores used for disposal or injection of water.

Of the non-producing wells, there were no wells drilled in 2019 that were capable of production and had reserves assigned to them.

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2019, the gross and net acres of undeveloped properties in which we had an interest and also the number of net acres for which our rights to explore, develop or exploit could expire within one year.

	GROSS ACRES	NET ACRES	NET ACRES EXPIRING WITHIN ONE YEAR
Alberta	268,721	152,141	2,586
TOTAL	**268,721**	**152,141**	**2,586**

Petrus expects that rights to explore, develop and exploit approximately 2,586 net acres of undeveloped land holdings may expire by December 31, 2020. A portion of Petrus' 2020 exploitation and development program may result in extending or eliminating such potential expirations. Petrus closely monitors land expirations as compared to its development program with the strategy of minimizing undeveloped land expirations relating to significant uncertainties that affect the anticipated development or production activities on properties with no contributed reserves.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties.

We may use certain financial instruments to hedge exposure to commodity price fluctuations on a portion of our crude oil and natural gas production. For further information, see note 11 to our financial statements for the year ended December 31, 2019.

Tax Horizon

Based on Sproule production forecasts, planned capital expenditures and the forecast commodity pricing employed in the Sproule Report, we estimate that we will not be required to pay current income taxes until at least 2025. See "*Risk Factors – Income Taxes*".

Costs Incurred

The following table summarizes capital expenditures incurred by us during the year ended December 31, 2019.

	PROPERTY ACQUISITION COSTS			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
TOTAL ($millions)	17.897	-	-	17.897

Drilling Activity

The following table sets forth the gross and net exploration and development wells drilled by us during the year ended December 31, 2019. All wells were drilled in Canada.

	EXPLORATION WELLS		DEVELOPMENT WELLS	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	10	3.146
Natural Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
TOTAL	-	-	10	3.146

Planned Capital Expenditures

On January 14, 2020, Petrus announced its planned capital expenditure budget of $9 million (excluding acquisitions and dispositions) for the first quarter of 2020 which is primarily focused the highest rates of return, lowest risk, condensate rich drilling opportunities in the Corporation's inventory at Ferrier, Alberta. The objectives of the 2020 capital plan are to invest capital systematically each quarter within funds flow, permitting excess funds each quarter to reduce debt. (see "*Development of Our Business – 2020 – Overview of Capital Expenditure Program*").

With the current volatility of commodity prices, we continue to actively monitor our 2020 capital expenditure plans in the context of expected cash flows from operating activities, potential service cost adjustments and portfolio allocation in order to prudently manage and maintain financial flexibility. The Corporation currently plans to drill throughout 2020 within funds flow and repay $1 to 2 million of debt each quarter.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Sproule Report for 2020 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light and Medium Crude Oil (Bbls/d)	NGLs (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (BOE/d)
PROVED				
Developed Producing	776.9	1,500.2	24,399	6,293.7
Developed Non-Producing	3.8	30.8	4,158	730.5
Undeveloped	4.9	690.2	7,044	2,004.6
TOTAL PROVED	734.5	2,221.2	34,094	8,638.2
PROBABLE	120.1	278.4	3,184	929
TOTAL PROVED PLUS PROBABLE	854.6	2,499.6	37,278	9,567.2

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2019, certain information in respect of our production, product prices received, royalties paid, operating expenses and resulting netback.

	Quarter Ended 2019				Year ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2019**
Average Daily Production [1]					
Light and Medium Crude Oil (Bbls/d)	1,704	1,679	1,247	1,834	1,616
Natural Gas Liquids (Bbls/d)	1,444	1,576	1,372	1,018	1,351
Conventional Natural Gas (MMcf/d)	32,145	32,350	30,998	32,641	32,032
Combined (BOE/d)	8,505	8,647	7,785	8,292	8,306
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	55.10	70.96	65.64	65.16	64.11
Natural Gas Liquids ($/Bbl)	36.02	19.91	11.49	20.62	22.13
Conventional Natural Gas ($/Mcf)	2.44	1.30	1.12	2.65	1.89
Combined ($/BOE)	26.36	22.29	16.99	27.39	23.35
Royalties Paid/(Received)					
Light and Medium Crude Oil ($/Bbl)	5.21	7.84	7.60	8.12	7.19
Natural Gas Liquids ($/Bbl)	6.21	3.59	2.03	3.11	3.79
Conventional Natural Gas ($/Mcf)	0.24	(0.16)	(0.10)	0.15	0.03
Combined ($/BOE)	3.02	1.57	1.17	2.78	2.15
Production Costs [2]					
Light and Medium Crude Oil ($/Bbl)	11.40	14.05	17.45	15.39	14.42
Natural Gas Liquids ($/Bbl)	5.78	5.93	6.44	7.15	6.25
Conventional Natural Gas ($/Mcf)	0.54	0.55	0.53	0.45	0.52
Combined ($/BOE)	5.03	5.55	5.69	5.77	5.51
Operating Netback [3]					
Light and Medium Crude Oil ($/Bbl)	38.49	49.07	40.59	41.65	42.50
Natural Gas Liquids ($/Bbl)	24.03	10.39	3.02	10.36	12.09
Conventional Natural Gas ($/Mcf)	1.66	0.91	0.69	2.05	1.34
Combined ($/BOE)	18.31	15.17	10.13	18.84	15.69

Notes:

(1) Before the deduction of royalties.
(2) Production costs are composed of direct costs incurred to operate both oil and natural gas wells. A number of assumptions are required to allocate these costs between product types.
(3) Operating Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. See "*Non-GAAP Financial Measures*"

Production Volume by Field

The following table indicates the average daily net production from our fields for the year ended December 31, 2019.

	Light and Medium Crude Oil (Bbls/d)	**NGLs (Bbls/d)**	**Conventional Natural Gas (Mcf/d)**	**Total Oil Equivalent (BOE/d)**	**Percentage (%)**
Alberta					
Central Alberta	383	173	6,173	1,585	19
Ferrier	1,088	1,178	24,110	6,284	76
Foothills[1]	145	-	1,749	438	5
TOTAL	1,616	1,351	32,032	8,306	100

Note:

(1) On December 9, 2019, Petrus entered into an agreement providing for the Foothills Disposition. For the year ended December 31, 2019, Petrus' Foothills assets contributed 5% of the Corporation's total average daily net production.

CAPITAL STRUCTURE

Share Capital

We are authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares. A description of our share capital is set forth below. For a complete description of our share capital, reference should be made to our articles, a copy of which has been filed on our SEDAR profile at *www.sedar.com*.

Common Shares

The holders of Common Shares are entitled to one vote at all meetings of our shareholders except at meetings of which only holders of a specified class of shares are entitled to vote. The holders of Common Shares are entitled to receive, subject to the prior rights and privileges attaching to any other class of our shares, such dividends as may be declared by us. Holders of Common Shares are entitled upon any liquidation, dissolution or winding-up of Petrus, subject to the prior rights and privileges attaching to any other class of our shares, to receive the remaining property and assets of the Corporation.

Preferred Shares

The Preferred Shares are issuable in series and the designation of, and the rights or privileges, restrictions and conditions attached to any series of Preferred Shares are to be established by our Board of Directors prior to the issuance thereof. The Preferred Shares have a preference over the Common Shares and any of our classes of shares ranking junior to the Preferred Shares with respect to the payment of dividends and the distribution of our assets in the event of liquidation, dissolution or winding-up of us or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs. No series of Preferred Shares has been designated to date and there are no Preferred Shares outstanding.

Stock Options

As at December 31, 2019, there were 2,361,958 Stock Options outstanding (the "**Outstanding Options**"), of which 35,000 were exercisable. Each Outstanding Option currently entitles the holder to acquire one Common Share at a price ranging from $0.26 to $14.00. The weighted average remaining life of the Outstanding Options is 1.69 years from December 31, 2019.

DSUs

As at December 31, 2019, there were 1,177,510 DSUs outstanding (the "**Outstanding DSUs**"). Each Outstanding DSU currently entitles the holder thereof to, upon redemption of the DSU (at Petrus' sole direction): (i) a cash payment equal to the weighted average of the prices at which the Common Shares trade on the TSX for the five (5) trading days immediately preceding the date of the redemption of such DSU: (ii) a number of Common Shares equal to the number of DSUs redeemed; or (iii) a combination of cash and Common Shares, in each case, in amounts calculated as set forth above.

RSUs

As at December 31, 2019, there were no RSUs outstanding (the "**Outstanding RSUs**"). Each Outstanding RSU will entitle the holder thereof, upon settlement of the RSU, to an amount equal to the weighted average of the prices at which the Common Shares trade on the TSX for the five (5) trading days immediately preceding the date of the settlement of such RSU, payable at Petrus' sole discretion in cash or Common Shares or a combination thereof.

DIVIDEND POLICY

Dividends and Dividend Policy

No dividends have been declared or paid on the Common Shares since the formation of Petrus. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. See "*Risk Factors – Substantial Capital Requirements*".

Other than as detailed below, there are no restrictions in Petrus' articles or elsewhere which could prevent it from paying dividends. It is not contemplated that any dividends will be paid on the Common Shares in the immediate future, as it is anticipated that all available funds will be invested to finance the growth of our business. The Board of Directors will determine if, and when, dividends will be declared and paid in the future from funds properly applicable to the payment of dividends based on its financial position at the relevant time. Any decision to pay dividends on the Common Shares will be made by the directors on the basis of Petrus' earnings, financial requirements and other factors existing at such future time, including commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. All of the Common Shares will be entitled to an equal share in any dividends declared and paid.

Under the terms of the Petrus Credit Facilities, the Corporation may not, without the prior written consent of a majority of its lenders, pay dividends or capital distributions in the event that such payment would result in a breach of the provisions of the Petrus Credit Facilities.

MARKET FOR OUR SECURITIES

The Common Shares trade on the TSX under the symbol "PRQ". The following table sets forth the price range and trading volume of the Common Shares on the TSX for the periods indicated.

	Price Range ($)		
Period	**Low**	**High**	**Trading Volume**
2019			
January	0.50	0.77	716,503
February	0.46	0.53	1,802,311
March	0.42	0.49	679,336
April	0.42	0.50	156,106
May	0.32	0.48	465,882
June	0.21	0.35	661,323
July	0.23	0.35	427,476
August	0.20	0.25	630,653
September	0.19	0.33	664,896
October	0.16	0.21	592,783
November	0.16	0.30	1,252,839
December	0.23	0.30	442,344
2020			
January	0.20	0.30	309,296
February (February 1 – 18)	0.19	0.21	218,934

Prior Sales

During the year ended December 31, 2019, Petrus granted an aggregate of 1,386,357 Options to acquire an aggregate of 1,386,357 Common Shares with a weighted average exercise price of $0.33, and 794,714 DSUs at a deemed value of $0.29 per DSU.

DIRECTORS AND OFFICERS

The name, municipality of residence, principal occupation for the prior five years and position with us of each of our directors and officers as of the date hereof are as follows:

Name and Residence	Position	Principal Occupation During Previous Five Years
Neil Korchinski Alberta, Canada	President and Chief Executive Officer and a Director (since November 7, 2016, formerly Vice President Engineering and Chief Operating Officer of Old Petrus (August, 2011 to February 2016))	Mr. Korchinski was Vice President Engineering and Chief Operating Officer of Petrus from February 2, 2016 to November 7, 2016 and held that position at Old Petrus from August 8, 2011 to February 2, 2016.
Patrick Arnell(1)(2)(3) Alberta, Canada	Director (since November 25, 2015, previously a director of Old Petrus (August, 2011 to February 2016))	Mr. Arnell was a director of Old Petrus from August 3, 2011 to February 2, 2016. Mr. Arnell is an independent businessman and is currently also the Chairman and Chief Executive Officer of Orix Investments Inc., a private investment company headquartered in Calgary, Alberta.
Donald Cormack(1)(2)(3) Alberta, Canada	Director (since November 25, 2015, previously a director of Old Petrus (October, 2014 to February 2016))	Mr. Cormack was a director of Old Petrus from October 8, 2014 to February 2, 2016. Mr. Cormack is a corporate director and he currently sits on the board of directors of several private entities.
Donald Gray(2)(3) Arizona, United States	Director (since November 25, 2015, previously a director of Old Petrus (December, 2010 to February 2016))	Mr. Gray is a private investor and Chairman of Petrus. He was director and the Chairman of Old Petrus from December 13, 2010 to February 2, 2016. Mr. Gray is a director and Chairman of Peyto Exploration & Development Corp. and Gear Energy Ltd, both TSX-listed oil and natural gas companies.
Stephen White(1)(2)(3) Alberta, Canada	Director (since February 2, 2016)	Mr. White is a retired business executive. In addition to his roles with the Corporation, he serves on the boards of directors and audit committees of several private corporations and is a member of a strategic advisory board of a New York based, energy focused, private equity fund.
Cheree Stephenson Alberta, Canada	Vice President, Finance and Chief Financial Officer (since November 25, 2015, formerly Chief Financial Officer of Old Petrus (August, 2011 to February 2016))	Ms. Stephenson is the Vice President Finance and Chief Financial Officer of Petrus and held the same position at Old Petrus from August 8, 2011 to February 2, 2016.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) The committees of the Board of Directors are constituted in compliance with NI 52-110 (as defined below) and National Instrument 58-101 – *Disclosure of Corporate Governance Practices*.

As a group, our directors and executive officers beneficially own, control or direct, directly or indirectly, 8.1 million Common Shares, representing approximately 16.3% of the outstanding Common Shares. Each above listed director will continue to hold office until the next annual general meeting of the Corporation or until a successor is duly elected or appointed in accordance with the ABCA, unless their office is earlier vacated.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

To our knowledge, none of our directors or executive officers (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 us), that 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 thirty 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 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.

Other than as set out below, to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us 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 us) 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.

Mr. Stephen H. White was a director of Lignol Energy Corporation ("**Lignol**"), a biofuels technology company listed on the TSX Venture Exchange. On August 22, 2014, a secured creditor of Lignol appointed a receiver over the assets and undertaking of Lignol.

Mr. Donald Cormack was a director of Walton Ontario Land 1 Corporation and Walton Edgemont Development Corporation ("**Walton Entities**"), registered entities (both Class 2 Reporting Issuers) engaged in property development, in Ontario and Alberta respectively. Mr. Cormack resigned as a director of Walton on April 13, 2017. Two weeks after Mr. Cormack's resignation, the Walton Entities filed for creditor protection under the *Companies Creditors' Arrangement Act* on April 28, 2017.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholders holding a sufficient number of our securities to affect materially the control of us is, 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.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholders holding a sufficient number of our securities to affect materially the control of us, has been subject to 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 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

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors – Conflicts of Interest*".

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such board members will be provided to us.

The ABCA provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

AUDIT COMMITTEE

The Audit Committee is comprised of Messrs. Cormack, Arnell and White. Mr. Cormack is the Chairman of the Audit Committee. The Audit Committee operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this Annual Information Form as Schedule "A".

The following chart sets out the assessment, within the meaning of National Instrument 52-110 – Audit Committees ("**NI 52-110**"), of each audit committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name, Province and Country of Residence	**Independent**	**Financially Literate**	**Relevant Education and Experience**
Mr. Donald Cormack (Chair)	Yes	Yes	Mr. Cormack was a partner with PricewaterhouseCoopers LLP from 1997 until his retirement in the summer of 2012, including as Calgary audit practice leader from 1997 to 2007. He has extensive financial accounting and reporting experience with both private and public companies of all sizes covering regulatory compliance, risk management, acquisitions, corporate restructuring, internal controls and governance in Canada and the U.S. Mr. Cormack is a corporate director and he currently sits on the board of directors of several private entities. He is a Chartered Professional Accountant, a graduate of the Institute of Corporate Directors Program and has a Bachelor of Commerce degree from the University of Saskatchewan.
Mr. Patrick Arnell	Yes	Yes	Mr. Arnell is currently the Chairman and Chief Executive Officer of Orix Investments Inc., a private investment company headquartered in Calgary, Alberta. Since 2005, he has been an early stage investor in several successful oil and gas enterprises as well as a founding shareholder and Chairman of Rangeland Industrial Service Ltd.; and, prior thereto, President and majority owner of Rayton Packaging Inc. from 1992 to 2005.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Mr. Stephen White	Yes	Yes	Mr. White is a retired business executive. In addition to his role with the Corporation, he serves on the boards of directors and audit committees of several private corporations and is a member of a strategic advisory board of a New York based, energy focused, private equity fund. He was President and Chief Financial Officer of Fort Chicago Energy Management Ltd., the general partner of Fort Chicago Energy Partners L.P., from its inception in 1997 until January 1, 2003 when he assumed the role of President and Chief Executive Officer, the position he held until his retirement as President and Chief Executive Officer of Veresen Inc. effective November 2012

Auditor's Fees

The table below summarizes the fees billed by Ernst & Young LLP for the years ended December 31, 2019 and December 31, 2018, respectively.

Year	Audit Fees (1)	Audit-Related Fees (2)	Tax Fees (3)	All Other Fees(4)
2019	$206,500	$Nil	$4,440	$Nil
2018	$207,000	$Nil	$5,550	$Nil

Notes:

(1) Audit fees include fees billed regarding the annual audit of the financial statements.
(2) Audit-related fees include amounts billed for assurance related services that are reasonably related to the performance of the audit of financial statements that are not reported under "Audit fees".
(3) Fees in connection with preparation of Canadian tax returns.
(4) Other fees charged by the auditors, including other non-audit products and services.

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 in the jurisdictions where the companies have assets or operations. While such regulations do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although laws and regulations are a matter of public record, the Corporation is unable to predict what additional laws, regulations 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 province of Alberta. The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. 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 federal or 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. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of 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

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. 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 pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, 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

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Exports of crude oil, natural gas and NGLs from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("**Cabinet**") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licenses. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. 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 criteria prescribed by the CER and the federal government. 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 and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete 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

Pipelines

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

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence 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. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's Indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to the Federal Court of Appeal decision quashing the original Certificate of Public Convenience and Necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019, and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada-United States Border remains dependant on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tones to or from British Columbia's north coast. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents; however, nothing has been publicly announced indicating the fate of the program, or whether any of the contracts have been assigned to industry proponents.

Natural Gas

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. 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. Companies without firm access 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. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network, (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and United States Natural Gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, 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. Nonetheless, In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project. Pre-construction activities began in November 2018, with a planned completion target of 2025. In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020.] The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the *Curtailment Rules*, as amended effective October 1 2019, the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 bbls/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint venturers may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbls/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for December 2019, January 2020 and February 2020 is set at 3.81 million bbls/d.

The Government of Alberta introduced certain policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Curtailment volumes affect sixteen of over 300 producers in Alberta. The *Curtailment Rules* are set to be repealed by December 31, 2020.

The Corporation **is not currently** subject to a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/ USMCA

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement, or "**CUSMA**". Legislative bodies in the three signatory countries must ratify the USMCA before it comes into force. Mexico's senate ratified the USMCA in June 2019. In late December 2019, the United States' House of Representatives approved the USMCA, and the USMCA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 to ratify the USMCA. According to Bill C-4, the USMCA will come into force two months after the House of Commons and the Senate pass Bill C-4. Until then, NAFTA remains the North American trade agreement currently in force. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final version ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. 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.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced. It is possible that the USMCA will come into force before the Government of Alberta's curtailment order is set to be repealed by the end of 2020.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

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 crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

Canada and ten other countries have agreed on the 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 CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam, and Singapore.

While it is uncertain what effect CETA, CPTPP, or any other trade agreements will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural 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. Oil and natural gas 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 Western Canada 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 Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan, and Manitoba approximately 19%, 6%, 20%, 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.

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the "**1995 Regulations**"). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. The Corporation does not have operations on Indian reserve lands.

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 provincial regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable typically depends in part on prescribed reference prices, well productivity, geographic 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 may be 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.

In addition, the federal government may from time to time provide incentives to the oil and natural gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, aimed to provide oil and natural gas businesses with eligible Canadian development expenses ("**CDE**")[1] and Canadian oil and gas property expenses ("**COGPE**")[2] with a first year deduction of one and a half times the deduction that is otherwise available for CDE. The definitions of "accelerated CDE" and "accelerated COGPE", as amended in November 2018, allow oil and natural gas businesses to claim an additional 15% deduction for new CDE, and an additional 5% deduction for new COGPE for taxation years that end before 2024 if such CDE or COGPE was incurred after November 20, 2018. The acceleration is reduced to 7.5% for new CDE and 2.5% for new COGPE for taxation years that begin after 2023 and end before 2028. Successored expenses, and costs in respect of Canadian resource properties not acquired at arms' length, will not qualify for treatment as accelerated CDE or accelerated COGPE.

The federal government also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies, of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totaling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

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, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. 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 *Royalty Guarantee Act (Alberta),* came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

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

[1] Drilling and completion costs are generally included in CDE and deductible at a rate of 30% per year, on a declining balance basis.
[2] COGPE generally includes intangible costs associated with the acquisition of Canadian resource properties and is deductible at a rate of 10% per year on a declining balance basis.

post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all 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.

Oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly, and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* was amended in 2014, and shortened the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three. Both the 2014 and 2015 production years became statute barred on December 31, 2018 as the pre-amendment four-year period applied for the years up to and including 2014. Going forward, producers will only have three years to amend their royalty calculations.

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 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.

Regulatory Authorities and Environmental Regulation

General

The Canadian 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, facility and pipeline 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 including carbon dioxide equivalents ("**CO2e**"), 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. 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 August 28, 2019, with the passing of Bill C-69, the CERA and the *Impact Assessment Act* ("**IAA**") came into force and the NEB Act and the *Canadian Environmental Assessment Act*, *2012* ("**CEAA 2012**") were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions will fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

Designated projects will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The impact assesment must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75km of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested.

On May 12, 2017, the federal government introduced Bill C-48 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 passed Bill C-48 as the *Oil Tanker Moratorium Act* which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53′00″ north latitude and west of 126°38′36″ west longitude) and, as a result, may negatively impact the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related legislation including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. 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 the Alberta Ministry of 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 the Alberta Ministry of Environment and Parks, the Alberta Ministry of Energy, 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. These regional plans may affect further development and operations in such regions.

Liability Management Rating Program

Alberta

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect the Corporation's ability to obtain or transfer licenses.

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program, including the Corporation, fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in *Redwater Energy Corporation (Re)* ("**Redwater**"), holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority 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 subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In Response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework.The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has 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 transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

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 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. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada. The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. 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, including Canada, 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 December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

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 in 2018, increasing annually until it reaches $50/tonne in 2022. This system applies 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. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

Six provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories. The federal fuel charge regime took effect in Saskatchewan, Manitoba, Ontario, and New Brunswick on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal carbon-pricing regime took effect in Alberta on January 1, 2020. Alberta, Saskatchewan, and Ontario challenged the constitutionality of the federal government's pricing regime. The reference in Alberta remains before the Alberta Court of Appeal, but the Saskatchewan and Ontario references have advanced in parallel where the appeal Courts ruled in favour of the constitutionality of the federal carbon tax. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada. The Court is set to hear the appeals in March of 2020. Ontario and Saskatchewan will cross-intervene in the appeals, along with the Attorneys General of Quebec, New Brunswick, Manitoba, British Columbia, and Alberta, who will intervene in both proceedings.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane 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. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural 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.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators so as to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. 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.

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to $30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed *Technology Innovation and Emissions Reduction* ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. A new edition of *Directive 017: Measurement Requirements for Oil and Gas Operations* is forthcoming. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

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 through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. 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.

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.

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 to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or 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 or 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, effective maintenance operations and the development of enhanced oil recovery technologies 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 and the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour gas in certain areas. An unintentional leak of sour 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 geological and seismic risks, 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. See "*Risk Factors – Insurance*". In either event, the Corporation could incur significant costs.

Weakness and Volatility in the Oil and Natural Gas Industry

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

Market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Risk Factors – Political Uncertainty*". These events and conditions have caused a significant reduction 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. See "*Risk Factors –Royalties and Incentives", "Risk Factors – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors – Climate Change Regulation*". In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis 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. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

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. See "*Risk Factors – Reserves Estimates*". 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. See "Risk Factors – Credit Facilities". 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. See "*Risk Factors – Additional Funding Requirements*".

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

The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or contract for the delivery of crude oil and NGLs by rail. 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, including:

- deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; and
- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of oil and natural gas.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. 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. 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.

See "*Industry Conditions – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Market Price

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 the 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, and/or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, 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 put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares 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 and assets 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 the resources 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 market conditions 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. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In late January 2020, the Canadian Partliament tabled Bill C-4, which once proclaimed into force, will ratify the USMCA. The USMCA is expected to fully replace NAFTA two months after Bill C-4 comes into force. See "*Industry Conditions - The North American Trade Agreement and Other Trade Agreements*". The U.S. 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 U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. 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 natural gas companies, including the Corporation.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. 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. Conflict and political uncertainty also continues to progress in the Middle East. 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 the 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 natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. In January 2020, the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction where the Corporation is active. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The federal Government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

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 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. See "*Industry Conditions – Liability Management Rating Program*" and "*Risk Factors – Third Party Credit Risk*".

Project Risks

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

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

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- 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;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- 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.

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines 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 firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to Cabinet's approval of the Trans Mountain Pipeline expansion, and construction on the pipeline expansion is underway. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Corporation's inability to realize the full economic potential of its products or in a reduction of the price offered for the Corporation's production. 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 have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is 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 material adverse effect on the Corporation's ability to process its production and deliver the same to market. 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.

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 implement and benefit from technological advantages. 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. 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

Fuel 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 systems 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. Advancements in energy efficient products have a similar effect on the demand for oil and natural 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 flow 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

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. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations", "Industry Conditions – Curtailment"* and *"Risk Factors – Liability Management".*

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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

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. 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 position

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.

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek, the AER introduced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay formation in the Fox Creek area in February 2015. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Waterflood

Regulatory water use restrictions and/or limited access to water or other fluids may impact the Corporation's production volumes from its waterflood

The Corporation undertakes or intends to undertake certain waterflooding programs, which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities the Corporation needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Corporation will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reservoirs. In addition, the Corporation may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Corporation's results of operations.

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, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with 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. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

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. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". Any 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, Saskatchewan 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. Changes to the AB LMR Program administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to the Corporation's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in *Redwater* on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program 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 natural 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 natural gas companies that may be disproportionately affected by price instability. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Climate change may pose varied and far ranging risks to the business and operations of the Corporation, both known and unknown, that may adversely affect the Corporation's business, financial condition, results of operations, prospects, reputation and share price

Chronic Climate Change Risks

The Corporation's exploration and production facilities and other operations and activities emit GHGs which may require the Corporation to comply with federal and/or provincial greenhouse gas emissions legislation. 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 to prevent climate change or mitigate its effects. 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

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. See "*Risk Factors – Seasonality*". In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Corporation to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, the Corporation may not be able to, or will incur greater costs to, carry out hydraulic fracturing operations while conducting completions operations in its Ferrier and Central Alberta operating areas.

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 which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses, and, in the long-term, potentially reducing the demand for oil and natural gas production, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or requiring asset impairments for financial statement purposes. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations",* "*Risk Factors – Reputational Risk Associated with the Corporation's Operations*" and "*Risk Factors – Changing Investor Sentiment*".

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets, such as the centrally located gas and liquids processing facility for the Corporation's Ferrier area, are located in locations that are proximate to forests and a wildfire may lead to significant downtime and/or damage to such assets.

Moreover, extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

Seasonality

Oil and natural gas operations are subject to seasonal 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 which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road 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 of the Corporation's 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 impassable muskeg.

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. Such an increase could also negatively impact the market price of the Common Shares.

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 and 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.

See "*Industry Conditions – Royalties and Incentives*".

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 conditions in, or affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Corporation, to access additional financing and/or the cost thereof. 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, or the cost of, additional financing.

As a result of global economic and political conditions and the domestic lending landscape, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable 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 additional capital or being required to repay all amounts owing thereunder

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which, from time to time, either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the

Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others**.**

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014, and while prices have recently increased they remain volatile as a result of various factors including limited egress options for Western Canadian oil and natural gas producers, actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed commodity prices could reduce 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 lenders require repayment of all or a portion of the amounts outstanding under its credit facilities 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 its credit facilities, 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 its credit facilities, the lenders under such credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

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;
- 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 and Cost of Material and Equipment

Restrictions on the availability and cost of materials and equipment may impede the Corporation's exploration, development and operating activities

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation's exploration, development and operating activities.

Diluent Supply

A decrease in, or restriction in access to, diluent supply may increase the Corporation's operating costs

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent, or a restriction in access to diluent, may cause its price to increase, increasing the cost to transport heavy oil and bitumen to market. An increase to the cost of bringing heavy oil and bitumen to market may increase the Corporation's overall operating cost and result in decreased net revenues, negatively impacting the overall profitability of the Corporation's heavy oil and bitumen projects.

Title to and Right to Produce from Assets

Defects in the title or rights to produce the Corporation's properties may result in a financial loss

The Corporation's actual title to and interest in its properties, and its right to produce and sell the oil and natural gas therefrom, may vary from the Corporation's records. In addition, there may be valid legal challenges or legislative changes that affect the Corporation's title to and right to produce from its oil and natural gas properties, which could impair the Corporation's activities and result in a reduction of the revenue received by the Corporation.

If a defect exists in the chain of title or in the Corporation's right to produce, or a legal challenge or legislative change arises, it is possible that the Corporation may lose all, or a portion of, the properties to which the title defect relates and/or its right to produce from such properties. This may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserves Estimates

The Corporation's estimated 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 reserves and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) 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 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 and such variations could be material.

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

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom 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, blowouts, leaks of sour 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.

Non-Governmental Organizations

The Corporation's properties may be subject to action by non-governmental organizations or terrorist attack

The oil and natural gas exploration, development and operating activities conducted by the Corporation may, at times, be subject to public opposition. Such public opposition could expose the Corporation to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. See "*Industry Conditions – Transportation Constraints and Market Access*". There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Corporation to incur significant and unanticipated capital and operating expenditures.

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

The Corporation's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment toward, or in respect of, the Corporation's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Corporation operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Corporation's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Similarly, the Corporation's reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by the Corporation's operations. In addition, 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 consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact the Corporation's reputation. See "*Risk Factors – Climate Change*".

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard the Corporation's reputation. Damage to the Corporation's reputation 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 Corporation's securities.

Changing Investor Sentiment

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

A number of factors, including the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in oil and natural 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 natural 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 Corporation's securities even if the Corporation's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Corporation's asset which may result in an impairment change.

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 to shareholders.

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. If the Corporation is unable to deal with this growth, it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licenses 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 and the associated abandonment and reclamation obligations 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, cash flow, results of operations, financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations, as the Board 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. Potential litigation may develop in relation 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 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.

Indigenous Claims

Indigenous claims may affect the Corporation

Indigenous peoples have claimed Indigenous rights and title 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 in the construction of infrastructure systems and facilities 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 its business, operations or affairs. 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.

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, generally, and of the Corporation's 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 a 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 or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation 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 Officers – Conflicts of Interest*".

Reliance on a Skilled Workforce and Key Personnel

An inability to recruit and retain a skilled workforce and key personnel may negatively impact the Corporation

The operations and management of the Corporation require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Corporation's business plans which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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. The Corporation does not have any key personnel insurance in effect. Contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. If the Corporation is unable to: (i) retain current employees; and/or (ii) recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact the Corporation's 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 the Corporation's land base, manage financial resources, analyze seismic information, administer contracts with 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 business activities or the Corporation's 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's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Corporation's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

The Corporation maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. The Corporation also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Corporation's efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage its information technology infrastructure. The Corporation applies technical and process controls in line with industry-accepted standards to protect its information, assets and systems, including a written incident response plan for responding to a cyber-security incident. 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 the Corporation's performance and earnings, as well as its reputation, and any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. 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.

Social Media

The Corporation faces compliance and supervisory challenges in respect of the use of social media as a means of communicating with clients and the general public

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Corporation's systems and obtain confidential information. The Corporation restricts the social media access of its employees and periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Corporation may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

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 and may acquire different energy-related assets; as a result, the Corporation may face unexpected risks or, alternatively, its exposure to one or more existing risk factors may be significantly increased, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information

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, assumption and uncertainties are found under the heading "*Special Note Regarding Forward-Looking Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS

There are no legal proceedings involving claims for damages for which the potential exposure is more than 10% of our current assets to which we are or was a party or in respect of which any of our properties are or were subject during the year ended December 31, 2019, nor are there any such proceedings known to us to be contemplated.

During the year ended December 31, 2019 there were: (i) no penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against us that we believe would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by us with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as set forth under "*Agreements with NGP*", there were no material interests, direct or indirect, of directors and officers of Petrus, any shareholder who beneficially owns more than 10% of the Common Shares, or any known associate or affiliate of such persons in any transaction completed within three years before the date of this Annual Information Form, or in any proposed transaction which has materially affected or would materially affect Petrus.

There were no material interests, direct or indirect, of directors and officers of Petrus, any shareholder who beneficially owns more than 10% of the Common Shares, or any known associate or affiliate of such persons in any transaction completed within three years before the date of this Annual Information Form, or in any proposed transaction which has materially affected or would materially affect Petrus.

AUDITOR, TRANSFER AGENT AND REGISTRAR

Our auditor is Ernst & Young LLP, Chartered Professional Accountants. Ernst & Young LLP has been our auditor since November 25, 2015.

Our transfer agent and registrar for the Common Shares is Odyssey Trust Company at its principal office in Calgary, Alberta.

MATERIAL CONTRACTS

Other than the Petrus Credit Facilities, the Petrus Term Loan and contracts entered in the ordinary course of business, the only material contracts entered into by us within our most recently completed financial year, or before the most recently completed financial year but which are still material and in effect, are set forth below:

Agreements with NGP

Nomination Rights Agreement

Petrus entered into a nomination rights agreement (the "**Nomination Rights Agreement**") upon completion of the Arrangement.

Such agreement provides that, as long as NGP owns: (i) at least 20% of the outstanding Common Shares (on a non-diluted basis), we will include two nominees of NGP; or (ii) at least 10% but not more than 20% of the outstanding Common Shares (on a non-diluted basis), we will include one nominee of NGP, among the nominees for election to the Board of Directors at each meeting of Shareholders at which directors are to be elected.

Additionally, such agreement provides that for a period of two years following the date of such agreement, we shall not do any of the following without the approval of NGP in its capacity as a shareholder:

(a) create, grant, issue, or modify any incentive security or any related plan or instrument; or

(b) enter into, modify or terminate any existing employment agreement, non-competition agreement, or similar agreement with any executive officer.

The Nomination Rights Agreement shall terminate upon agreement between NGP and Petrus or upon NGP holding less than 10% of the Common Shares (on a non-diluted basis).

A copy of the Nomination Rights Agreement has been filed on our SEDAR profile at *www.sedar.com*.

Registration Rights Agreement

The following is a description of certain provisions of our registration rights agreement (the "**Registration Rights Agreement**") dated February 2, 2016, pursuant to which we granted certain rights to NGP and to our officers at the time of entering into of the Registration Rights Agreement. The following description of certain provisions of the Registration Rights Agreement is a summary only, is not comprehensive and is qualified in its entirety by reference to the full text of the Registration Rights Agreement, a copy of which has been filed on our SEDAR profile at *www.sedar.com*.

Demand Rights

The Registration Rights Agreement provides that at any time after we become a reporting issuer in any province or territory of Canada, NGP has the right, subject to certain limitations, to request that we file all necessary documents, including a prospectus in Canada or, in certain circumstances, a registration statement in the United States, to distribute to the public all or any portion of the Registrable Securities (as defined below) held by NGP. We must use our commercially reasonable efforts to file a preliminary prospectus or registration statement, as applicable, within 90 days of receipt of a notice from NGP of exercise of such a demand right.

Pursuant to the Registration Rights Agreement, the other parties (other than Petrus) to the Registration Rights Agreement (the "**Other Holders**") shall be notified of NGP's demand request and each of the Other Holders and Petrus may elect to participate in such an offering (through an issuance of Common Shares from treasury in the case of Petrus). The rights of NGP to participate in a distribution or registration pursuant to the foregoing demand rights may be limited to the extent that the underwriter for the distribution or registration determines that market or other relevant factors require a limitation of the number of Registrable Securities to be sold by NGP. To the extent that the underwriter imposes such a limitation, NGP may participate to the exclusion of other participants.

Subject to certain exceptions, NGP shall not be entitled to demand more than three demand requests in total under the Registration Rights Agreement. Further, the Registrable Securities proposed to be distributed under an underwritten offering must have a fair market value of at least $5,000,000 or be all of NGP's remaining holdings of Registrable Securities.

Piggyback Rights

The Registration Rights Agreement provides that NGP and the Other Holders have the right, subject to certain limitations, to include some or all of the Registrable Securities held by them in any distribution of Registrable Securities (whether a distribution from treasury or from other securityholders) qualified for distribution under applicable securities laws by way of a prospectus in Canada or, in certain circumstances, by way of a registration statement in the United States.

The rights of NGP and the Other Holders to participate in a distribution or registration pursuant to the foregoing piggyback rights may be limited to the extent that the underwriter for the distribution or registration determines that market or other relevant factors require a limitation of the number of Registrable Securities to be sold by NGP and the Other Holders.

As long as NGP owns at least 10% of the equity interest in Petrus, we shall not grant any piggyback rights or similar rights to any person unless such rights are expressly made subject to the prior right of NGP and the Other Holders in the Registration Rights Agreement.

Additional Terms

We are responsible for all fees and expenses incurred in connection with the exercise by NGP of any of its rights under the Registration Rights Agreement other than, except in limited circumstances, the expenses of counsel or other advisors of NGP and the Other Holders. In addition, each of NGP and the Other Holders exercising its rights shall pay the underwriting discounts, commissions and similar fees and transfer taxes applicable to their respective Registrable Securities.

Pursuant to the Registration Rights Agreement, we are obliged to indemnify NGP and the Other Holders exercising its rights under the Registration Rights Agreement for losses arising out of any violation by Petrus of applicable securities laws, any untrue statement or alleged untrue statement of a material fact contained in any prospectus or registration statement of ours, or any omission or alleged omission to state therein a material fact required to be stated therein or necessary to make any statement therein not misleading (excluding any information provided by NGP or the Other Holders), and any breach by us of the Registration Rights Agreement. Pursuant to the Registration Rights Agreement, each of NGP and the Other Holders exercising its rights under the Registration Rights Agreement is obliged to severally indemnify Petrus for losses arising out of any untrue statement of material fact made by it contained in any prospectus or registration statement of ours, or any omission of a material fact required to be stated therein or necessary to make any statement therein not misleading.

The Registration Rights Agreement will terminate at such time as NGP no longer holds any Registrable Securities.

Under the Registration Rights Agreement, "**Registrable Securities**" means the Common Shares held by NGP and/or the Other Holders immediately prior to the date that NGP first becomes entitled to exercise demand rights pursuant to the Registration Rights Agreement; provided, however, that, in connection with any U.S. initial public offering or Canadian initial public offering, Registrable Securities shall be deemed to include all Common Shares held by NGP and/or the Other Holders at such time; *provided, further*, that a Registrable Security shall cease to be a Registrable Security upon the earlier of the time (a) a registration statement covering such Registrable Security has been declared effective by the U.S. Securities Act and such Registrable Security has been sold or disposed of pursuant to such effective registration statement, or (b) such Registrable Security has been disposed of pursuant to any section of Rule 144 (or any similar provision then in force) or Regulation S under the U.S. Securities Act.

INTERESTS OF EXPERTS

As of December 31, 2019, no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by us during, or related to, our most recently completed financial year other than Sproule, our independent engineering evaluator, and Ernst & Young LLP, our independent auditor.

Reserve estimates contained in this Annual Information Form are derived from reserve reports prepared by Sproule. To our knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of Petrus or of one of our associates or affiliates: (i) were held by Sproule when Sproule prepared the report, valuation, statement or opinion in question, or (ii) are to be received by Sproule. Sproule did not, nor is any director, officer or employee of Sproule expected to be elected, appointed or employed as a director, officer or employee of Petrus or of any associate or affiliate thereof.

Petrus' auditors are Ernst & Young LLP, Chartered Professional Accountants, who have prepared independent auditors' reports dated February 18, 2020 in respect of Petrus' financial statements for the year ended and as at December 31, 2019 and who reviewed the financial statements for the three and nine months ended and as at September 30, 2019. Ernst & Young LLP is independent in the context of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

As at the date hereof, the partners and associates of Burnet, Duckworth & Palmer LLP, as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at *www.sedar.com*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans will be contained in our information circular and proxy statement for our annual general meeting of shareholders to be held on May 5, 2020. Additional financial information is contained in our financial statements and the related management's discussion and analysis for the year ended December 31, 2019.

SCHEDULE "A"

MANDATE OF THE AUDIT COMMITTEE OF THE BOARD OF DIRECTORS

I. PURPOSE

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

II. OBJECTIVES

The Audit Committee's primary objectives are:

1. to assist the Board to meet its responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. to provide better communication between directors and external auditors;

3. to assist the Board's oversight of the auditor's qualifications and independence;

4. to assist the Board's oversight of the credibility, integrity and objectivity of financial reports;

5. to strengthen the role of the outside directors by facilitating discussions between directors on the Audit Committee, management and external auditors;

6. to assist the Board's oversight of the Corporation's compliance with legal and regulatory requirements; and

7. to review the risks that may affect Petrus and the risk management policies and procedures of the Corporation.

III. COMPOSITION

The Audit Committee shall be comprised of three or more directors as determined by the Board of Directors, none of whom are members of management of Petrus, except as otherwise permitted in National Instrument 52-110 ("**NI 52-110**"), all of whom are "independent" and "financially literate" (as such terms are defined in NI 52-110). Audit Committee members may enhance their familiarity with finance and accounting by participating in educational programs conducted by the Corporation or an outside consultant. In addition, at least one member of the Audit Committee must have accounting or related financial management expertise, as the Corporation's Board of Directors interprets such qualification in its business judgment.

The members of the Audit Committee shall be appointed by the Board of Directors by resolution and remain as members of the Audit Committee until their successors are duly appointed. Unless a Chair is elected by the full Board of Directors, the members of the Audit Committee may designate a Chair by majority vote of the full Audit Committee membership.

IV. MEETINGS

The Audit Committee shall meet at least four times annually, or more frequently as circumstances dictate. As part of its job to foster open communication, the Audit Committee should meet at least annually with management, internal auditors (if any) and the independent auditors to discuss any matters that the Audit Committee or each of these groups believe should be discussed privately. In addition, the Audit Committee or at least its Chair should meet with the independent auditors and management quarterly to review the Corporation's financial statements and MD&A consistent with Section V.4 below. The Audit Committee should also meet with management and independent auditors on an annual basis to review and discuss annual financial statements and the management's discussion and analysis of financial conditions and results of operations.

A quorum for meetings of the Audit Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee shall be the same as those governing the Board.

V. RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties, the Audit Committee shall endeavour to:

Documents/Reports Review

1. Review and, if deemed appropriate, update this Mandate, at least annually, as conditions dictate.

2. Review and recommend to the Board the organization's annual and interim financial statements, MD&A, earnings press releases and review any reports or other financial information submitted to any governmental body or the public, including any certification, report, opinion or review rendered by the independent auditors.

3. Review the reports to management prepared by the independent auditors and management's responses.

4. Review with financial management and the independent auditors the quarterly financial statements prior to their filing or prior to the release of earnings.

5. Review significant findings during the year, including the status of previous significant audit recommendations.

6. Periodically assess the adequacy of procedures for the review of corporate disclosure that is derived or extracted from the financial statements.

7. Periodically discuss guidelines and policies to govern the processes by which the Chief Executive Officer and senior management assess and manage the Corporation's exposure to risk.

8. Report to the Board any issues that arise with respect to the quality or integrity of the Corporation's financial statements, compliance with legal or regulatory requirements, performance and independence of the Corporation's auditors, or performance of the internal audit function.

9. Reviewing any inquiry or investigation by governmental or professional authorities respecting any independent audits carried out on the Corporation and any steps to deal with any such issues.

Independent Auditors

10. Recommend to the Board the external auditors to be nominated for appointment by the shareholders.

11. Approve the compensation of the external auditors.

12. On an annual basis, the Audit Committee should review and discuss with the auditors all significant relationships the auditors have with the Corporation to determine the auditors' independence.

13. Review and, as appropriate, resolve any material disagreements between management and the independent auditors and review, consider and make a recommendation to the Board regarding any proposed discharge of the auditors when circumstances warrant.

14. 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.

15. Periodically consult with the independent auditors, without the presence of management, about internal controls and the fullness and accuracy of the organization's financial statements.

16. Periodically assess the Corporation's internal controls, including Corporation's risk management processes.

17. Review the audit scope and plan of the independent auditor.

18. Oversee the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for Petrus.

19. Pre-approve the completion of any non-audit services by the external auditors and, with the assistance of the auditors, determine which non-audit services the external auditor is prohibited from providing. The Audit Committee may delegate to one or more members of the Audit Committee authority to pre-approve non-audit services in satisfaction of this requirement and if such delegation occurs, the pre-approval of non-audit services by the Audit Committee member to whom authority has been delegated must be presented to the Audit Committee at its first scheduled meeting following such pre-approval. The Audit Committee shall be entitled to adopt specific policies and procedures for the engagement of non-audit services if:

(a) the pre-approval policies and procedures are detailed as to the particular service;

(b) the Audit Committee is informed of each non-audit service; and

(c) the procedures do not include delegation of the Audit Committee's responsibilities to management.

The Audit Committee will satisfy the pre-approval requirement set forth in this paragraph if:

(d) the aggregate amount of all non-audit services that were not pre-approved is reasonably expected to constitute no more than 5% of the total amount of fees paid by Petrus and its subsidiary entities to the auditors during the fiscal year in which the services are provided;

(e) Petrus or a subsidiary entity, as the case may be, did not recognize the services as non-audit services at the time of the engagement; and

(f) the services are promptly brought to the attention of the Audit Committee and approved, prior to completion of the audit, by the Audit Committee or by one or more of its members to whom authority to grant such approvals has been delegated by the Audit Committee.

Financial Reporting Processes

20. In consultation with the independent auditors, annually review the organization's financial reporting processes and the quality and appropriateness of the Corporation's accounting principles as applied in its financial reporting.

21. Consider and approve, if appropriate, major changes to the Corporation's auditing and accounting principles and practices as suggested by the independent auditors or management.

22. Review risk management policies and procedures of Petrus (i.e. litigation and insurance).

Process Improvement

23. Request reporting to the Audit Committee by each of management and the independent auditors of any significant judgments made in the management's preparation of the financial statements and the view of each group as to appropriateness of such judgments.

24. Following completion of the annual audit, review separately with each of management and the independent auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.

25. Review any significant disagreements among management and the independent auditors in connection with the preparation of the financial statements.

26. Review with the independent auditors and management the extent to which changes or improvements in financial or accounting practices, as approved by the Audit Committee, have been implemented. (This review may be conducted at an appropriate time subsequent to implementation of changes or improvements, as decided by the Audit Committee.)

27. Conduct and authorize investigations into any matters brought to the Audit Committee's attention and within the Audit Committee's scope of responsibilities. The Audit Committee shall be empowered to retain and to approve compensation for any independent counsel and other professionals to assist in the conduct of any investigation.

28. Review the systems that identify and manage principal business risks.

29. Assist with the establishment of a procedure for:

(a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(b) the confidential, anonymous submission by employees of Petrus of concerns regarding questionable accounting matters, auditing matters and matters set forth in Petrus' Code of Business Conduct and Ethics,

which procedure shall be set forth in a "Whistle Blower Policy" to be adopted by the Board in connection with such matters.

Ethical and Legal Compliance

30. Assist with the establishment of a Code of Business Conduct and Ethics and ensure that management has established a system to enforce same.

31. Review management's monitoring of the Corporation's compliance with the Code of Business Conduct and Ethics.

32. In consultation with the auditors, consider the review system established by management regarding the Corporation's financial statements, reports and other financial information disseminated to governmental organizations and the public in the context of the applicable legal requirements.

33. On at least an annual basis, review with the Corporation's auditors or counsel, as appropriate, any legal matters that could have a significant impact on the organization's financial statements, the Corporation's compliance with applicable laws and regulations and inquiries received from regulators or government agencies.

Other

34. Perform any other activities consistent with this Mandate, Petrus' by-laws and governing law, as the Audit Committee or the Board of Directors deems necessary or appropriate.

35. In connection with the performance of its responsibilities as set forth above, the Audit Committee shall have the authority to engage outside advisors and to pay outside auditors and advisors.

Standards of Liability

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

SCHEDULE "B"

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR (FORM 51-101 F2)

To the Board of Directors of Petrus Resources Ltd. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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 for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's management and Board of Directors:

			Net Present Value of Future Net Revenue Before Income Tax Expenses (10% Discount Rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves (Country)**	**Audited (M$)**	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule Associates Limited	December 31, 2019	Canada	-	$392,446	-	$392,446

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 5 for events and circumstances occurring after the effective date of our report, entitled "*Evaluation of the P&NG Reserves of Petrus Resources Ltd. (as of December 31, 2019)*".

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta Canada

February 18, 2020

(signed) by *"Paul B. Jung"*
Paul B. Jung, P. Eng.
Project Leader, Senior Petroleum Engineer

(signed) by *"Weldon Dueck"*
Weldon D. Dueck, P. Eng.
Senior Petroleum Engineer

(signed) by *"Tamara Warren"*
Tamara Warren, P. Eng.
Petroleum Engineer

(signed) by *"Ian Kirkland"*
Ian K. Kirkland, P. Geol.
Senior Geologist

(signed) by *"Cameron P. Six"*
Cameron P. Six, P. Eng.
President and Chief Executive Officer

SCHEDULE "C"

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

Management of Petrus Resources Ltd. ("**Petrus**") is responsible for the preparation and disclosure of information with respect to Petrus' oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated and reviewed Petrus' reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "B" to the Annual Information Form of Petrus for the year ended December 31, 2019 (the "**AIF**").

The reserves committee (the "**Reserves Committee**") of the board of directors of Petrus (the "**Board of Directors**") has:

- reviewed Petrus' procedures for providing information to the independent qualified reserves evaluator, Sproule Associates Limited ("**Sproule**");
- met with Sproule to determine whether any restrictions affected the ability of Sproule to report without reservation; and
- reviewed the reserves data with management and with Sproule.

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

- the content and filing with securities regulatory authorities of Form 51-101F1, incorporated into the AIF, containing reserves data and other oil and natural gas information;
- the filing of Form 51-101F2, which is the report of Sproule on the reserves data; and
- the content and filing of this report.

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

(signed) "Neil Korchinski"	*(signed) "Cheree Stephenson"*
Neil Korchinski President & Chief Executive Officer	Cheree Stephenson Vice President, Finance & Chief Financial Officer
(signed) "Donald Gray"	*(signed) "Stephen White"*
Donald Gray Director & Chairman of the Reserves Committee	Stephen White Director

February 18, 2020