Petrus Resources

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2022

Dated March 14, 2023

TABLE OF CONTENTS

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.

"**Acquired Entities**" has the meaning ascribed thereto under "*Development of our Business – 2022*".

"**Acquisition**" has the meaning ascribed thereto under "*Development of our Business – 2022*".

"**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.

"**ATB Facility**" has the meaning ascribed thereto under "*Development of our Business – 2022*".

"**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 IFRS.

"**GP**" has the meaning ascribed thereto under "*Development of our Business – 2022*".

"**IFRS**" means International Financial Reporting Standards.

"**InSite**" means InSite Petroleum Consultants Limited, independent petroleum consultants of Calgary, Alberta.

"**InSite Report**" means the report prepared by InSite dated February 7, 2023 and effective December 31, 2022 evaluating the crude oil, NGLs and natural gas and future net production revenues attributable to the properties of Petrus.

"**LP**" has the meaning ascribed thereto under "*Development of our Business – 2022*".

"**MD&A**" means Petrus' Management's Discussion and Analysis for the year ended December 31, 2022.

"**New Credit Facilities**" has the meaning ascribed thereto under "*Development of our Business – 2022*".

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

"**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.

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

"**Prior Operating Facility**" means Petrus's former operating credit facility, which was repaid in full in 2022. See "*Development of our Business – 2022*".

"**Prior Syndicated Facility**" means Petrus' former reserve based revolving credit facility, which was repaid in full in 2022. See "*Development of our Business – 2022*".

"**Prior Term Loan**" has the meaning ascribed thereto under "*Development of our Business – 2021*".

"**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.

"**Rights Offering**" has the meaning ascribed thereto under "*Development of our Business – 2022*".

"**RSU Plan**" means the restricted share unit plan for officers, employees and consultants of the Corporation and its subsidiaries.

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

"**Second Lien Facility**" has the meaning ascribed thereto under "*Development of our Business – 2022*".

"**Stand-By Guarantors**" has the meaning ascribed thereto under "*Development of our Business – 2022*".

"**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 defenses, 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
$000s or M$	thousands of dollars

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;
- Planned capital expenditures and drilling activity in 2023, including, but not limited to, the focus thereof;
- development plans for our proved and probable undeveloped reserves;
- plans for funding future development costs including the timing of future development projects;
- 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;
- Petrus' anticipated taxability;
- 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;
- assumptions regarding exchange rates and inflationary pressures;
- 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;
- 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;
- supply chain risks and inflationary pressures;
- 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 the heading "*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", which is provided on a per unit of production basis. Petrus employs this measure to analyze financial performance, financial position and cash flow. This non-GAAP financial measure does not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. This non-GAAP financial measure should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from operating activities, and cash flow used in investing activities, as indicators of Petrus' performance.

Non-GAAP Financial Measures

We believe operating netback 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. Operating netback is calculated as oil and natural gas realized revenue (price) less royalties, operating and transportation expenses. 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. Petrus' operating netback is disclosed in on the Non-GAAP Financial Measures section of the MD&A which includes its most directly comparable GAAP measure.

Non-GAAP Financial Ratios

Operating netback per unit of production measure 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 and one that provides investors with information that is also commonly presented by other crude oil and natural gas producers. Operating netback per unit of production is calculated as operating netback divided by weighted average daily production.

Further information

For more information, including a reconciliation of operating netback and operating netback per unit of production to the applicable GAAP measures, please see our MD&A, a copy of which has been filed on our SEDAR profile at *www.sedar.com*.

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 transactions contemplated in connection therewith. On February 2, 2016, pursuant to the Arrangement, Petrus filed articles of amendment to change its name to "Petrus Resources Ltd.".

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.

2020

Overview of Capital Expenditure Program

During the financial year ended December 31, 2020, Petrus invested $14.3 million to drill 4.0 gross (3.2 net) wells predominantly in the Ferrier/Strachan area of Alberta. Average production for the year ended December 31, 2020 was 6,608 BOE/d (approximately 15% light and medium crude oil and 15% natural gas liquids).

General Business Development

On March 10, 2020, Ms. Cheree Stephenson tendered her resignation as the Vice President, Finance and Chief Financial Officer of the Corporation.

On April 9, 2020, Mr. Chris Graham was appointed Vice President, Finance and Chief Financial Officer of the Corporation.

2021

Overview of Capital Expenditure Program

During the financial year ended December 31, 2021, Petrus invested $27 million to drill 9.0 gross (6.4 net) wells predominantly in the Ferrier/Strachan area of Alberta. Average production for the year ended December 31, 2021 was 6,009 BOE/d (approximately 17% light and medium crude oil and 17% natural gas liquids).

General Business Development

On March 11, 2021, Mr. Ken Gray was appointed to the Board, and on April 12, 2021 Mr. Ken Gray was appointed as President and Chief Executive Officer. Mr. Neil Korchinski, former President and Chief Executive Officer, and Mr. Chris Graham, former Vice President, Finance and Chief Financial Officer, departed Petrus concurrent with Mr. Ken Gray's appointment. In June 2021, Mr. Peter Verburg was appointed to the Board of Directors.

On June 1, 2021, Petrus announced that it had entered into an agreement with the lenders under the Prior Credit Facilities to extend borrowing base termination date on its Prior Syndicated Facility from May 31, 2021 to June 14, 2021. Petrus also announced that the lender, in respect of its then existing subordinated secured term loan (the "**Prior Term Loan**"), had also agreed to extend the maturity date of the Prior Term Loan from July 31, 2021 to August 16, 2021. On June 30, 2021 Petrus announced that it had entered into further agreements to extend the maturity of each of its Prior Syndicated Facility (from June 30, 2021 to July 14, 2021) and Prior Term Loan (from August 16, 2021 to September 14, 2021) and that Macquarie Bank Limited, the Corporation's then lender under the Prior Term Loan, was changed to Blue Oak Partners (Canada) Inc. Petrus subsequently entered into a number of agreements with its lenders to further extend the maturity date of its Prior Syndicated Facility and Prior Term Loan, and on August 30, 2021 announced that it has entered into a series of agreements with respect to, among other things, the reduction of Petrus' total debt by approximately $49 million through the issuance of $25.8 million of Common Shares at $0.55 per share, the extension of the maturity date of Prior Syndicated Facility to December 31, 2021 and the settlement of the Prior

Term Loan by way of the issuance of $15.8 million of Common Shares at $0.55 per share (collectively, the "**Restructuring Transactions**").

As part of the Restructuring Transactions, Petrus entered into binding subscription agreements with each of Don Gray, a member of the Board (who then owned or controlled (directly or indirectly) 13,022,476 Common Shares (representing 26.3% of the then outstanding Common Shares)), and Glen Gray (who then owned or controlled (directly or indirectly)) 6,708,867 Common Shares (representing 13.6% of the outstanding Common Shares) to complete a private placement of Common Shares at an issue price of $0.55 per share for total proceeds of $10.0 million (the "**Equity Financing**").

In addition, in connection with the settlement of the Prior Term Loan, Petrus entered into a shares for debt agreement with Stuart Gray and Glen Gray, who had prior thereto taken assignment of the Prior Term Loan, pursuant to which Petrus agreed to issue an aggregate of 28,727,273 Common Shares at an issue price of $0.55 per share (for total consideration of $15.8 million), in consideration for the full payment and discharge of amounts outstanding under the Prior Term Loan, then totaling $39.3 million (the "**Term Loan Settlement**").

On September 22, 2021, Petrus announced that it had closed the Restructuring Transactions. The gross proceeds of the Equity Financing, were used to reduce outstanding indebtedness under the Prior Credit Facilities and, as a result of the completion of Restructuring Transactions, the borrowing base termination date on its Prior Syndicated Facility was extended from December 31, 2021 to May 31, 2022.

Pursuant to the Equity Financing, Mr. Don Gray acquired 15,636,364 Common Shares, resulting in Mr. Don Gray then owning, or exercising control or direction over, 28,658,840 Common Shares or approximately 29.7% of the then issued and outstanding Common Shares (on a non-diluted basis). Pursuant to the Equity Financing and the Term Loan Settlement, Mr. Glen Gray acquired 15,636,364 Common Shares, resulting in Mr. Glen Gary then beneficially owning, or exercising control or direction over, 22,352,231 Common Shares or approximately 23.2% of the then issued and outstanding Common Shares (on a non-diluted basis). Pursuant to the Equity Financing and the Term Loan Settlement, Mr. Stuart Gray acquired 15,636,364 Common Shares, resulting in Mr. Stuart Gray then beneficially owning, or exercising control or direction over, 20,578,231 Common Shares or approximately 21.3% of the then issued and outstanding Common Shares (on a non-diluted basis).

In connection with its approval of the Restructuring Transactions, specifically of the Equity Financing and the Term Loan Settlement on the basis of "financial hardship", the TSX informed the Corporation that the Corporation would be the subject of a remedial delisting. On October 20, 2021, Petrus announced it had received confirmation from the TSX that the TSX has completed its review of the Corporation and determined the Petrus satisfies the TSX's applicable requirements for continued listing.

In November 2021, the syndicate of lenders reconfirmed Petrus' borrowing base of $64.8 million under its Prior Syndicated Facility, which was subsequently reduced by $2.75 million on December 31, 2021 and was further reduced by a $5.0 million on March 31, 2022. In addition, Petrus and the lenders under the Prior Syndicated Facility agreed to a cash sweep provision under which 75% of Petrus' excess cash flow will be used to accelerate repayment of the Prior Syndicated Facility. In the event that the lenders reduced the borrowing base below the amount drawn at the time of redetermination, the Corporation would have had 60 days to eliminate any shortfall by repaying amounts in excess of the new re-determined borrowing base.

2022

Overview of Capital Expenditure Program

Petrus incurred $96.7 million of capital expenditures in 2022 (excluding acquisitions and dispositions), compared to $26.9 million in 2021. 85% of total capital included drilling and completion costs related to 21 gross (15.6 net) wells in Ferrier and North Ferrier as well as 12% of capital on pipeline, equipment and facilities costs and the remaining capital spent on land and corporate costs.

General Business Development

On March 1, 2022, the Corporation announced that it had entered into a definitive agreement in respect of the acquisition (the "**Acquisition**") of a privately owned limited partnership (the "**LP**") and its general partner (the "**GP**", and together, the "**Acquired Entities**") for total consideration of approximately $14.4 million, consisting of 10 million Common Shares issued at a deemed price of $1.44 per Common Share. The Acquisition closed on March 14, 2022 and was a related party transaction under applicable securities legislation as, among other things, the Acquired Entities were managed and directed by Ken Gray, the President and Chief Executive Officer of both the GP and the Corporation, and Ken Gray and two of the Corporation's controlling shareholders (Stuart Gray and Glen Gray) owned or controlled, in aggregate, approximately 69.5% of the LP's units and 50% of the GP's shares.

On May 2, 2022, Petrus closed a rights offering, pursuant to which Petrus issued approximately 14.8 million Common Shares at a price of $1.35 per Common Share for gross proceeds of approximately $20 million (the "**Rights Offering**"). In connection with the Rights Offering, the Corporation entered into standby purchase agreements with each of Don Gray, Stuart Gray and Glen Gray (collectively, the "**Stand-By Guarantors**"). As a result of the exercise of the basic subscription privilege and additional subscription privilege by the holders of rights (including the Stand-By Guarantors), the Stand-By Guarantors did not acquire any Common Shares in connection with the Rights Offering pursuant to their stand-by commitments. The Rights Offering was part of a larger debt restructuring strategy that was intended to provide the Corporation with improved long-term stability and increased liquidity. As further described below, the net proceeds of the Rights Offering were used to repay amounts drawn under the Prior Credit Facilities.

On May 25, 2022, Mr. Matt Skanderup was appointed as Petrus' Chief Operating Officer and Mr. Mathew Wong was appointed as Petrus' Chief Financial Officer.

On May 27, 2022, Petrus entered into definitive documentation and obtained two new credit facilities (the "**New Credit Facilities**") totaling up to $55 million and completed certain transactions in connection therewith. The New Credit Facilities consist of a $30 million reserve based, secured operating revolving loan facility with ATB Financial (the "**ATB Facility**") and a second lien secured term facility in the amount of $25 million (the "**Second Lien Facility**") with Stuart Gray. The New Credit Facilities, together with the net proceeds of the Rights Offering, were used to repay in full all amounts owning under the Prior Credit Facilities. The Second Lien Facility was a related party transaction under applicable securities legislation as Mr. Gray was a controlling shareholder of Petrus and then owned or exercised control or direction over (directly or indirectly) 25,805,896 Common Shares (representing approximately 21.2% of the outstanding Common Shares on a non-diluted basis).

Recent Developments

On February 7, 2023, Ms. Lindsay Hatcher was appointed as Vice President, Commercial & Corporate Development of the Corporation.

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 focused on property exploitation, strategic acquisitions and risk-managed exploration in Alberta. Through a combination of acquisitions and drilling, our production averaged 9,113 BOE/d for the year ending December 31, 2022.

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 include light oil and liquids rich natural gas locations which management believes are economic in today's commodity price environment. See "*Principal Properties*".

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 and Cost of Material Equipment*".

Personnel

As at December 31, 2022, Petrus had 17 full-time employees, and 16 contract workers.

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against the Corporation or its subsidiary entities, or any voluntary bankruptcy, receivership or similar proceedings by the Corporation or any of its subsidiary entities within the three most recently completed financial year or during or proposed for the current financial year.

Reorganization

There have been no material reorganization of the Corporation or any of its subsidiary entities within the three most recently completed financial year or during or proposed for the current financial year.

PRINCIPAL PROPERTIES

Ferrier Area – West Central Alberta

The Ferrier 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 64% working interest in 95,594 gross (47,491 net) acres of land in the Ferrier area, of which 53,011 gross (28,114 net) acres are undeveloped and 42,583 gross (19,377 net) acres are developed. Petrus acquired the assets in the Ferrier area through a combination of corporate and asset acquisitions, farm-in agreements with joint venture partners. Exploration, development and production activities in the Ferrier area are primarily directed toward oil, natural gas and natural gas liquids in the Cardium formation.

InSite assigned approximately 28,077 MBOE of proved reserves and 43,914 MBOE of proved plus probable reserves to the Ferrier area in the InSite Report. During the year ended December 31, 2022, the Ferrier area provided Petrus with average production of approximately 6,239 BOE/d (including 2,706 Bbls/d of oil and natural gas liquids and 21,198 Mcf/d of conventional natural gas) from 146.0 gross (87.1 net) producing wells. As at December 31, 2022, we operated approximately 86% of our production in the Ferrier area. The majority of Petrus' Ferrier production is pipeline connected to its owned and operated gas plant. Conventional 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 $102 million in the Ferrier area in the year ended December 31, 2022. 18 gross (13.6 net) wells were drilled in the year ended December 31, 2022 and 7 gross (5.2 net) were on production by year end. The majority of the capital invested at Ferrier during 2022 was directed towards drilling, completion, tie-in and equipping of the new wells.

North Ferrier – West Central Alberta

The North Ferrier area is a new development just north of the core Ferrier area. Petrus currently holds an average 82% working interest in 12,018 gross (6,073 net) acres of land in the North Ferrier area, of which 9,172 gross (5,304 net) acres are undeveloped and 2,846 gross (769 net) acres are developed. Petrus acquired the assets in the North Ferrier area through a combination of corporate and asset acquisitions and land sales. Exploration, development and production activities in the North Ferrier area are primarily directed toward oil, conventional natural gas and natural gas liquids in the Cardium formation.

InSite assigned approximately 6,572 MBOE of proved reserves and 10,215 MBOE of proved plus probable reserves to the North Ferrier area in the InSite Report. During the year ended December 31, 2022, the Ferrier area provided Petrus with average production of approximately 1,107 BOE/d from 2 gross (1.0 net) producing wells. As at December 31, 2022, we operated approximately 91% of our production in the North Ferrier area. The majority of Petrus' North Ferrier production is pipeline connected to a non-operated gas plant in which Petrus owns a partial interest.

Petrus invested approximately $7.8 million in the North Ferrier area in the year ended December 31, 2022. 2 gross (1.0 net) wells were drilled in the year ended December 31, 2022 and all were on production by year end. The majority of the capital invested at North Ferrier during 2022 was directed towards drilling, completion, tie-in and equipping of the new wells and the expansion of North Ferrier production processing infrastructure.

Petrus also has three non-core properties located in Alberta. These properties are described below.

Central Alberta – Central Alberta

Petrus' Central Alberta area is located approximately 70 kilometers southwest of Edmonton, Alberta. Petrus currently holds an average 82% working interest in 112,979 gross (72,134 net) acres of land in the Central Alberta area, of which 37,102 gross (21,882 net) acres are undeveloped and 75,877 gross (50,252 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 Central Alberta area are primarily directed towards light oil in the Glauconite formation.

InSite assigned approximately 4,740 MBOE of proved reserves and 8,616 MBOE of proved plus probable reserves in Central Alberta in the InSite Report. During the year ended December 31, 2022, Petrus had average production of approximately 1,230 BOE/d (including 397 Bbls/d of oil and natural gas liquids and 4,993 Mcf/d of conventional natural gas) from 108 gross (92.2 net) producing wells in the Central Alberta area. As at December 31, 2022, we operated approximately 97% of the production in the in the area. Substantially all of our production in the area is pipeline connected to owned and operated oil batteries and gas plants. Clean oil and conventional natural gas are transferred directly to sales pipelines once processed.

Petrus invested $1.3 million of capital in this area in 2022.

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 41% working interest in 46,523 gross (22,025 net) acres of land in the Foothills area, of which 28,970 gross (16,857 net) acres are undeveloped and 17,553 gross (5,168 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.

InSite assigned approximately 1,325 MBOE of proved reserves and 2,369 MBOE of proved plus probable reserves to the Foothills area in the InSite Report. During the year ended December 31, 2022, the Foothills area provided Petrus with average production of approximately 481 BOE/d (including 88 Bbls/d of oil and natural gas liquids and 2,360 Mcf/d of conventional natural gas) from 51 gross (14.9 net) producing wells. Petrus currently operates 51% of its Foothills production and has a working interest in a variety of compressor stations, gas plants and pipeline infrastructure. Substantially all of our Foothills natural gas production is pipeline connected. Conventional 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 2022.

Kakwa

The Kakwa area is located approximately 70 km south of Grande Prairie, Alberta. Petrus currently holds an average 100% working interest in 10,437 gross (10,437 net) acres of land in the Kakwa area, of which 10,121 gross (10,121 net) acres are undeveloped and 316 gross (316 net) acres are developed. Petrus has 1 well producing from the Dunvegan formation. This is a new area and is currently being evaluated for further development. Petrus acquired its Kakwa assets through a combination of asset acquisitions, farm-ins, and land sales.

InSite assigned approximately 134 MBOE of proved reserves and 899 MBOE of proved plus probable reserves to the Kakwa area in the InSite Report dated December 31, 2022. During the year ended December 31, 2022, Petrus had average production of approximately 56 BOE/d from 1.0 gross (1.0 net) producing wells in the Kakwa area. Petrus currently operates 100% of its Kakwa production. Conventional natural gas and natural gas liquids are processed at third party gas plant and then go directly to sales. Oil is trucked to a terminal that is pipeline connected that then goes directly to sales.

Petrus did not invest significant capital in this area in 2022.

STATEMENT OF RESERVES DATA

The report of InSite on reserve data in Form 51-101F2 and the report of management and directors on oil and natural gas disclosure in Form 51-101F3 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 InSite with an effective date of December 31, 2022, contained in the InSite Report, which has a preparation date of February 7, 2023. The InSite Report evaluated, as at December 31, 2022, 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 InSite 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. InSite was engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The InSite Report is based on certain factual data supplied by us and InSite'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 InSite. InSite 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 InSite'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, 2022 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 InSite represents 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 conventional 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, 2022
FORECAST PRICES AND COSTS

	GROSS RESERVES						
RESERVES CATEGORY	**Light and Medium Crude Oil**	**Natural Gas Liquids**	**Solution Natural Gas**	**Conventional Natural Gas**	**Coalbed Methane Gas**	**Sulphur**	**Total BOE**
	(Mbbls)	**(Mbbls)**	**(MMcf)**	**(MMcf)**	**(MMcf)**	**(Mlt)**	**(MBOE)**
PROVED:							
Developed Producing	958.2	4,615.7	5,353.8	73,210.4	202.7	0.0	17,809.3
Developed Non-Producing	0.0	64.0	0.0	1,187.6	0.0	0.0	261.9
Undeveloped	2,168.5	5,523.5	20,089.4	90,510.0	0.0	0.0	22,777.1
TOTAL PROVED	3,126.7	10,203.2	25,443.2	164,908.0	202.7	0.0	40,848.3
PROBABLE	3,106.5	5,396.7	23,904.4	99,931.4	34.3	0.0	25,164.2
TOTAL PROVED PLUS PROBABLE	6,233.2	15,599.9	49,347.6	264,839.5	236.9	0.0	66,012.5

	NET RESERVES						
RESERVES CATEGORY	**Light and Medium Crude Oil**	**Natural Gas Liquids**	**Solution Natural Gas**	**Conventional Natural Gas**	**Coalbed Methane Gas**	**Sulphur**	**Total BOE**
	(Mbbls)	**(Mbbls)**	**(MMcf)**	**(MMcf)**	**(MMcf)**	**(Mlt)**	**(MBOE)**
PROVED:							
Developed Producing	814.5	3,529.7	4,763.6	63,316.0	236.3	0.0	14,936.2
Developed Non-Producing	0.0	46.8	0.0	1,039.0	0.0	0.0	219.9
Undeveloped	1,744.6	4,401.5	17,393.9	79,465.8	0.0	0.0	19,390.4
TOTAL PROVED	2,559.1	7,977.9	22,157.5	143,820.8	236.3	0.0	34,546.5
PROBABLE	2,525.5	4,083.4	20,944.7	85,036.3	44.4	0.0	20,789.0
TOTAL PROVED PLUS PROBABLE	5,084.6	12,061.3	43,102.2	228,857.1	280.7	0.0	55,335.5

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	381,133.8	311,376.0	266,263.9	235,332.1	212,855.4	17.83
Developed Non-Producing	4,195.5	2,926.2	2,148.2	1,647.4	1,307.1	9.77
Undeveloped	327,232.7	210,153.3	139,020.9	92,969.8	61,390.6	7.17
TOTAL PROVED	712,562.0	524,455.5	407,433.0	329,949.3	275,553.1	11.79
PROBABLE	476,819.0	280,469.5	181,936.5	126,084.4	91,328.1	8.75
TOTAL PROVED PLUS PROBABLE	1,189,381.0	804,925.0	589,369.5	456,033.7	366,881.2	10.65

(1) Unit value calculation based on net BOE reserves

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	377,018.1	309,717.9	265,558.1	235,016.8	212,708.3
Developed Non-Producing	3,209.2	2,446.1	1,905.7	1,520.8	1,239.0
Undeveloped	250,577.6	159,710.4	103,518.5	66,722.7	41,256.2
TOTAL PROVED	630,805.0	471,874.4	370,982.3	303,260.3	255,203.5
PROBABLE	367,587.2	212,686.2	134,719.0	90,653.5	63,406.2
TOTAL PROVED PLUS PROBABLE	998,392.2	684,560.6	505,701.3	393,913.8	318,609.7

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2022
FORECAST PRICES AND COSTS (1)(2)(3)

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	INVESTMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAX ($000s)	INCOME TAX ($000s)	FUTURE NET REVENUE AFTER INCOME TAX ($000s)
Total Proved	1,853,595.0	287,034.3	470,937.1	313,786.4	69,275.1	712,562.0	81,757.0	630,805.0
Total Probable	1,226,622.7	207489.5	322,277.4	206,036.7	14,000.2	476,819.0	109,231.8	367,587.2
Total Proved plus Probable	3,080,217.7	494,523.8	793,214.5	519,823.1	83,275.3	1,189,381.0	190,988.8	998,392.2

otes:

(1) Total revenue includes product revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.
(3) Well abandonment costs are less salvage.

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BY PRODUCT GROUP BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE [1]
			($/BOE)
Proved	Light and Medium Crude Oil [2]	105,271.8	13.96
	Conventional Natural Gas [3]	301,853.5	11.19
	Coalbed Methane [3]	341.9	8.68
	Other Revenue	-34.3	-
	Total	407,433.0	11.79
Proved plus Probable	Light and Medium Crude Oil [2]	171,628.3	11.81
	Conventional Natural Gas [3]	417,390.2	10.24
	Coalbed Methane [3]	385.3	8.24
	Other Revenue	-34.3	-
	Total	589,369.5	10.65

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, 2022, excluding price risk management activities, were $103.67/Bbl for light and medium crude oil, $4.33/Mcf for conventional natural gas and $49.24 /Bbl for NGLs. InSite employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2022 in the InSite Report in estimating Reserves Data using forecast prices and costs as shown in the table below.

FORCAST PRICES AND COSTS ASSUMPTION

YEAR (1) (2)	WTI @ CUSHING	BRENT BLEND	CDN/US EXCHANGE RATE	WTI @ CUSHING	EDM REF PRICE	HARDISTY 25 API	WESTERN CANADA SELECT	HEAVY 12 API	CONDEN - SATE	BUTANE	PROPANE	ETHANE
	$US/BBL	$US/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL	$C/BBL
2023(3)	80.00	82.00	0.750	106.67	103.67	78.67	78.67	71.67	105.74	55.98	42.50	14.47
2024	77.00	80.50	0.750	102.67	97.67	79.67	75.17	72.67	101.57	52.74	41.02	15.05
2025	75.50	81.50	0.750	100.67	94.67	79.67	75.67	72.67	99.40	51.12	40.71	14.35
2026	77.01	82.00	0.750	102.68	95.18	82.18	78.18	75.18	100.89	51.40	40.93	14.58
2027	78.55	82.50	0.750	104.73	95.73	83.73	80.23	76.73	102.43	51.70	41.17	14.89
2028	80.12	84.15	0.750	106.83	97.65	85.41	82.65	78.41	104.48	52.73	41.99	15.20
2029	81.72	85.83	0.750	108.96	99.60	87.12	84.30	80.12	106.57	53.78	42.83	15.52
2030	83.36	87.55	0.750	111.14	101.59	88.86	85.99	81.86	108.70	54.86	43.69	15.84
2031	85.03	89.30	0.750	113.37	103.63	90.64	87.71	83.64	110.88	55.96	44.56	16.17
2032	86.73	91.09	0.750	115.63	105.70	92.45	89.46	85.45	113.10	57.08	45.45	16.51
2033	88.46	92.91	0.750	117.95	107.81	94.30	91.25	87.30	115.36	58.22	46.36	16.86
2034	90.23	94.77	0.750	120.31	109.97	96.18	93.08	89.18	117.67	59.38	47.29	17.21
2035	92.03	96.66	0.750	122.71	112.17	98.11	94.94	91.11	120.02	60.57	48.23	17.56
2036	93.87	98.60	0.750	125.17	114.41	100.07	96.84	93.07	122.42	61.78	49.20	17.93
2037	95.75	100.57	0.750	127.67	116.70	102.07	98.77	95.07	124.87	63.02	50.18	18.30
2038	97.67	102.58	0.750	130.22	119.03	104.11	100.75	97.11	127.36	64.28	51.18	18.68
2039	99.62	104.63	0.750	132.83	121.41	106.19	102.76	99.19	129.91	65.56	52.21	19.07
2040	101.61	106.72	0.750	135.48	123.84	108.32	104.82	101.32	132.51	66.87	53.25	19.47

YEAR (1) (2)	HENRY HUB	AECO C	ALBERTA 1 YR FIRM	ALBERTA SPOT	AGGRE-GATOR	ALBERTA AGRP	SASK SPOT	SUMAS SPOT	BC STN 2	DAWN	SULPHUR

	$US/MM BTU	C$/MM BTU	C$/MMBTU	C$/MMBTU	C$/MM BTU	C$/MMBTU	C$/MM BTU	C$/MM BTU	C$/MM BTU	C$/MM BTU	$/LT
2023(3)	4.75	4.33	4.03	4.03	3.88	4.13	4.43	6.23	4.23	6.33	60.00
2024	4.50	4.50	4.20	4.20	4.05	4.30	4.60	6.44	4.40	5.75	61.20
2025	4.35	4.30	4.00	4.00	3.85	4.10	4.40	6.28	4.20	5.55	62.42
2026	4.40	4.37	4.07	4.07	3.92	4.17	4.47	6.39	4.27	5.62	63.67
2027	4.49	4.45	4.15	4.15	4.00	4.25	4.55	6.52	4.35	5.73	64.95
2028	4.58	4.54	4.24	4.24	4.09	4.34	4.64	6.65	4.44	5.85	66.24
2029	4.67	4.63	4.33	4.33	4.18	4.43	4.73	6.79	4.53	5.98	67.57
2030	4.76	4.73	4.43	4.43	4.28	4.53	4.83	6.92	4.63	6.10	68.92
2031	4.86	4.82	4.52	4.52	4.37	4.62	4.92	7.06	4.72	6.23	70.30
2032	4.96	4.92	4.62	4.62	4.47	4.72	5.02	7.21	4.82	6.36	71.71
2033	5.05	5.02	4.72	4.72	4.57	4.82	5.12	7.35	4.92	6.49	73.14
2034	5.16	5.12	4.82	4.82	4.67	4.92	5.22	7.50	5.02	6.62	74.60
2035	5.26	5.22	4.92	4.92	4.77	5.02	5.32	7.66	5.12	6.76	76.09
2036	5.36	5.32	5.02	5.02	4.87	5.12	5.42	7.81	5.22	6.90	77.62
2037	5.47	5.43	5.13	5.13	4.98	5.23	5.53	7.97	5.33	7.04	79.17
2038	5.58	5.54	5.24	5.24	5.09	5.34	5.64	8.13	5.44	7.19	80.75
2039	5.69	5.65	5.35	5.35	5.20	5.45	5.75	8.29	5.55	7.34	82.37
2040	5.81	5.76	5.46	5.46	5.31	5.56	5.86	8.46	5.66	7.49	84.01

Notes:

(1) All prices escalated at 2% per year after 2040.
(2) All costs escalated at 2% per year after 2023.
(3) First year forecast is for 12 months.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of our gross reserves as at December 31, 2022, derived from the InSite Report using forecast prices and cost estimates, reconciled to our gross reserves as at December 31, 2021.

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

PROVED RESERVES	LIGHT AND MEDIUM CRUDE OIL	NATURAL GAS LIQUIDS	CONVENTIONAL NATURAL GAS	COALBED METHANE	TOTAL OIL EQUIVALENT
	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
December 31, 2021	2,611.7	8,371.3	132,613.8	97.0	33,101.5
Extensions[(1)]	214.8	778.2	19,540.0	0.0	4,249.6
Improved Recovery[(2)]	0.0	0.0	0.0	0.0	0.0
Discoveries[(3)]	0.0	63.8	1,613.4	0.0	332.7
Technical Revisions[(4)]	-32.2	-509.9	-8,974.3	103.3	-2,020.9
Acquisitions	589.8	1,790.6	24,278.5	0.0	6,426.8
Dispositions	0.0	0.0	0.0	0.0	0.0
Economic Factors	74.3	301.3	6,927.4	22.5	1,534.1
Production	-331.6	-592.1	-11,091.0	-20.1	-2,775.6
December 31, 2022	3,126.7	10,203.2	164,907.8	202.7	40,848.3

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, 2021	2,299.9	3,812.1	67,054.9	15.3	17,290.4
Extensions[(1)]	172.4	338.4	6,193.5	0.0	1,543.1
Improved Recovery[(2)]	0.0	0.0	0.0	0.0	0.0
Discoveries[(3)]	0.0	9.0	251.9	0.0	51.0
Technical Revisions[(4)]	-120.5	-487.6	-4,104.6	15.9	-1,289.9
Acquisitions	716.5	1,617.0	27,975.0	0.0	6,996.1
Dispositions	0.0	0.0	0.0	0.0	0.0
Economic Factors	38.2	107.8	2,560.9	3.0	573.6
Production	0.0	0.0	0.0	0.0	0.0
December 31, 2022	3,106.5	5,396.7	99,931.6	34.2	25,164.2

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, 2021	4,911.6	12,183.4	199,668.7	112.3	50,391.8
Extensions[(1)]	387.2	1,116.6	25,733.5	0.0	5,792.7
Improved Recovery[(2)]	0.0	0.0	0.0	0.0	0.0
Discoveries[(3)]	0.0	72.8	1,865.2	0.0	383.7
Technical Revisions[(4)]	-152.9	-997.5	-13,078.9	119.2	-3,310.8
Acquisitions	1,306.3	3,407.6	52,253.5	0.0	13,422.9
Dispositions	0.0	0.0	0.0	0.0	0.0
Economic Factors	112.5	409.1	9,488.3	25.5	2,107.7
Production	-331.6	-592.1	-11,091.0	-20.1	-2,775.6
December 31, 2022	6,233.2	15,599.9	264,839.4	236.9	66,012.4

Notes:

(1) Includes promotions from probable to proved and category transfer.
(2) Includes recompletions and workovers.
(3) Includes infill drilling.
(4) Includes land expiries, working interest and facility changes.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by InSite 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 seven years through ordinary course capital expenditures. In some cases, it will take longer than seven years to develop these reserves; however, Petrus expects that the large majority of our booked undeveloped projects will be completed within a seven-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 – Reserves 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
2020	223.9	943.3	1,915	52,448	0.0	0.0	110.3	3,492.3
2021	103.5	1,725.4	15,289	82,065	0.0	0.0	1,032.4	5,797.0
2022	765.8	2,168.5	36,573	90,510	0.0	0.0	2,347.9	5,523.5

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. InSite has assigned 22,777 MBOE of proved undeveloped reserves in the InSite Report with $314 million of associated undiscounted capital forecasted to be spent in the first three years. Development of properties scheduled beyond two years is associated with properties which are being exploited at a controlled pace. The pace of development could be accelerated from that scheduled and is typically dependent on capital allocation.

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
2020	203.6	1,950.9	1,737	44,581	0.0	0.0	100.0	2,390.1
2021	0.0	1,644.6	0	36,907	0.0	0.0	0.0	1,919.3
2022	732.3	2,394.0	30,969	62,248	0.0	0.0	1,649.5	3,123.5

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. InSite has assigned 21,199 MBOE of probable undeveloped reserves in the InSite Report with $206 million of associated undiscounted capital forecasted to be spent in the first four years. Development of properties scheduled beyond two years is associated with properties which are being exploited at a controlled pace. The pace of development could be accelerated from that scheduled and is typically dependent on capital allocation.

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 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 InSite 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*".

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 InSite as part of the InSite Report. These abandonment and reclamation costs have been estimated in the InSite Report and attributed to all properties that have been assigned reserves in the InSite Report, and have been taken into account by InSite 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 $19.7 million, discounted at 10%, to abandon and reclaim all wells, pipelines and facilities associated with our proved reserves $69.3 million undiscounted, before tax). Abandonment and reclamation costs undiscounted and expected to be paid over the next six years total approximately $13 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, 2022 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 InSite Report of future net revenue attributable to our proved reserves and proved plus probable reserves (using forecast prices and costs).

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2023	112,557	122,732
2024	119,861	177,167
2025	81,369	158,927
2026	-	60,998
TOTAL UNDISCOUNTED	313,786	519,823
TOTAL DISCOUNTED AT 10%	277,551	442,376

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 ATB Facility 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, 2022. All of Petrus' wells are located onshore.

	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	126	68.7	180	128.3	163	71.0	235	145.8	32	15.1
TOTAL	126	68.7	180	128.3	163	71.0	235	145.8	32	15.1

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.

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2022, 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	138,376	82,278	2,400
TOTAL	138,376	82,278	2,400

Petrus expects that rights to explore, develop and exploit approximately 2,400 net acres of undeveloped land holdings may expire by December 31, 2023. A portion of Petrus' 2023 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, 2022.

Tax Horizon

Based on InSite production forecasts, planned capital expenditures and the forecast commodity pricing employed in the InSite Report, we estimate that we will not be required to pay current income taxes until at least 2026. See "*Risk Factors – Income Taxes*".

Costs Incurred

The following table summarizes capital expenditures incurred by us during the year ended December 31, 2022.

	PROPERTY ACQUISITION COSTS			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
TOTAL ($millions)	$15,200	$1,759	$-	$94,985

Drilling Activity

The following table sets forth the gross and net exploration and development wells drilled by us during the year ended December 31, 2022. All wells were drilled in Canada. See *Principal Properties* for a description of Petrus' current and proposed exploration and development activities.

	EXPLORATION WELLS		DEVELOPMENT WELLS	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	-	-
Natural Gas	-	-	21	15.6
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
TOTAL	-	-	21	15.6

Planned Capital Expenditures

Petrus' 2023 planned capital expenditure budget is $130 to $135 million. Capital spending will be focused on Roughly 90% of the budget is directed towards drilling in the Ferrier and North Ferrier areas, and 10% towards land, facilities and corporate development. The 2023 capital budget was developed using a 2023 average price forecast of US$77/bbl WTI for oil, an AECO gas price of $4.00/GJ and a foreign exchange rate of US$0.73. (See "Development of Our Business – Recent Developments").

Given the inherent volatility of our commodity based business, Petrus has always been committed to being disciplined and flexible. Petrus is continuously evaluating the 2023 capital program to ensure it meets our investment threshold to optimize shareholder return.

Production Estimates

The following table discloses for each product type the total volume of production estimated by InSite in the InSite Report for 2023 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light and Medium Crude Oil and Condensate (Bbls/d)	NGLs (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (BOE/d)
PROVED				
Developed Producing	2,019.5	1,168.5	36,122.47	9,208.36
Developed Non-Producing	0.5	1.6	78.1	15.21
Undeveloped	230.14	231.2	5,551.60	1,386.60
TOTAL PROVED	2,250.1	1,803.6	51,332.33	12,609.09
PROBABLE	756.4	157.5	4,151.2	1,605.84
TOTAL PROVED PLUS PROBABLE	3,006.6	1,961.1	55,483.56	14,214.93

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2022, certain information in respect of our production, product prices received, royalties paid, operating expenses and resulting netback.

	Quarter Ended 2022				Year ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2022
Average Daily Production [1]					
Light and Medium Crude Oil (Bbls/d)	1,250	1,073	957	2,458	1,436
Natural Gas Liquids (Bbls/d)	1,207	1,055	997	1,121	1,094
Conventional Natural Gas (MMcf/d)	29,530	30,913	28,107	33,201	30,441
Combined (BOE/d)	7,379	7,280	6,639	9,113	7,604
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	110.12	133.36	111.04	106.85	113.19
Natural Gas Liquids ($/Bbl)	60.12	74.63	62.24	56.90	63.26
Conventional Natural Gas ($/Mcf)	5.20	6.15	4.83	5.69	5.49
Combined ($/BOE)	49.31	56.58	45.81	56.55	52.46
Royalties Paid/(Received)					
Light and Medium Crude Oil ($/Bbl)	15.02	25.36	29.01	14.90	19.24
Natural Gas Liquids ($/Bbl)	12.17	15.47	21.70	13.87	15.59
Conventional Natural Gas ($/Mcf)	0.52	0.57	0.95	0.56	0.64
Combined ($/BOE)	6.60	8.39	11.46	7.77	8.44
Production Costs [2]					
Light and Medium Crude Oil ($/Bbl)	24.06	30.88	33.48	15.88	23.39
Natural Gas Liquids ($/Bbl)	9.85	12.63	12.44	14.00	12.18
Conventional Natural Gas ($/Mcf)	0.81	0.87	0.87	0.81	0.84
Combined ($/BOE)	8.93	10.09	10.36	8.94	9.53
Operating Netback [3]					
Light and Medium Crude Oil ($/Bbl)	71.04	77.13	48.55	76.06	70.56
Natural Gas Liquids ($/Bbl)	38.10	46.53	28.10	29.03	35.49
Conventional Natural Gas ($/Mcf)	3.88	4.71	3.02	4.32	4.01
Combined ($/BOE)	33.78	38.10	23.99	39.84	34.48

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 per Bbl, Mcf or BOE 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, 2022.

	Light and Medium Crude Oil (Bbls/d)	NGLs (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (BOE/d)	Percentage (%)
Alberta					
Central Alberta	257	144	4,974	1,231	16
Ferrier	1,068	929	22,663	5,774	76
Foothills	83	9	2,630	530	7
Kakwa	29	12	174	69	1
TOTAL	1,436	1,094	30,441	7,605	100

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 have been designated to date and there are no Preferred Shares outstanding.

Options

As at December 31, 2022, there were 8,519,709 Options outstanding (the "**Outstanding Options**"), of which 498,958 were exercisable. Each Outstanding Option currently entitles the holder to acquire one Common Share at a price ranging from $0.23 to $2.81. The weighted average remaining life of the Outstanding Options is 2.3 years from December 31, 2022.

DSUs

As at December 31, 2022, there were 1,618,702 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, 2022, 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 New 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 New 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**
2022			
January	0.84	1.70	5,246,600
February	1.36	1.83	3,098,400
March	1.35	2.60	5,771,100
April	1.80	2.72	4,179,000
May	1.90	3.00	4,244,400
June	1.92	3.42	4,092,500
July	1.57	2.24	1,932,800
August	1.65	2.28	1,992,700
September	1.70	2.15	2,894,200
October	2.00	2.93	2,305,600
November	2.39	3.01	1,399,000
December	2.13	2.67	1,327,800
2023			
January	2.00	2.56	1,099,700
February	1.70	2.17	1,066,200
March 1-14	1.75	2.23	635,540

Prior Sales

Other than RSUs, DSUs and Options, Petrus does not have any classes of securities that are outstanding but that are not listed or quoted on a market place.

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
Ken Gray Alberta, Canada	Director and President and Chief Executive Officer	Mr. Gray is a Petroleum Engineer. Since 2009, he has been the President of a private oil and gas company with operations in Alberta.
Patrick Arnell(1)(2)(3) Alberta, Canada	Director	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	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 and Chairman of the Board	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.
Peter Verburg (1)(3) Alberta, Canada	Director	Mr. Verburg is a Calgary businessman with experience as a journalist, investment banker and entrepreneur. Since 2020, Mr. Verburg is the founder and CEO of a Calgary based digital health company.
Mathew Wong Alberta, Canada	Chief Financial Officer (since May, 2022) and Vice President, Finance	Mr. Wong has been the controller of Petrus since February 2017 and was promoted as the Vice President of Finance in April 2021 and to Chief Financial Officer in May, 2022. He served as the Vice President of Finance with another TSX listed oil & gas company since May 2014.
Matt Skanderup Alberta, Canada	Chief Operating Officer (since May, 2022)	Mr. Skanderup has been with Petrus since 2014 as a production engineer. He was promoted to production manager in 2018 and was promoted to Chief Operating Officer in May 2022.
Lindsay Hatcher Alberta, Canada	Vice President, Commercial & Corporate Development (since February, 2023)	Lindsay Hatcher joined Petrus as the Manager, Marketing & Joint Venture in 2014. She was promoted to Vice President of Commercial & Corporate Development in February 2023

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, 92.5 million Common Shares, representing approximately 75% 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. 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.
Mr. Peter Verburg	Yes	Yes	Mr. Verburg previously served on the Corporation's Board from 2010 to 2017. He is a Calgary businessman with extensive experience in the Canadian energy sector, and has a diverse business background, with experience as a journalist, investment banker and entrepreneur. Most recently, Mr. Verburg is the founder and CEO of a Calgary based digital health company.

Auditor's Fees

The table below summarizes the fees billed by Ernst & Young LLP for the years ended December 31, 2022 and December 31, 2021, respectively.

Year	Audit Fees (1)	Audit-Related Fees (2)	Tax Fees (3)	All Other Fees(4)
2022	$285,000	$Nil	$16,900	$Nil

2021	$164,630	$Nil	$9,990	$6,168

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 operating in the Canadian oil and gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government; and with respect to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Western Canadian oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

The Corporation's assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of the Corporation's upstream oil and natural gas business include all manner of activities associated with the exploration for and production of oil and natural gas, including, among other matters: (i) permits for the drilling of wells and construction of related infrastructure; (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, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct 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 following discussion provides an overview of some of the principal aspects of the legislation, regulations, agreements, orders, directives and other pertinent conditions that impact the oil and gas industry in Western Canada, particularly in the province of Alberta, where the Corporation's assets are primarily located. While these matters 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 matters carefully.

Pricing and Marketing in Canada

Crude Oil

Oil producers are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary determinant of oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("**OPEC**") forecasts robust growth in world oil demand in 2023, spurred by the relaxation of China's zero-COVID policy. OPEC predicts global oil demand to rise by 2.25 million barrels per day in 2023, despite newly emerging COVID-19 variants, interest rate increases in major economies and other uncertainties with respect to the world economy.

In February 2022, Russian military forces invaded Ukraine. Ongoing military conflict between Russia and Ukraine has significantly impacted the supply of oil and gas from the region. In addition, certain countries including Canada and the United States have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy in addition to the near term effects on Russia. The long-term impacts of the conflict remain uncertain.

Natural Gas

Negotiations between buyers and sellers determine 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 of sale.

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. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. 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 of sale.

Exports from Canada

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the Canadian Energy Regulator Act (the "**CERA**"). 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.

Transportation Constraints and Market Access

Capacity to transport production from Western Canada to Eastern Canada, the United States and other international markets has been, and continues to be, a major constraint on the exportation of crude oil, natural gas and NGLs. Although certain pipeline and other transportation projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and socio-political factors. Due in part 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.

Specific Pipeline Updates

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, the project budget has risen to $21.4 billion as of February 2022. The pipeline is expected to be in service in the third quarter of 2023, an extension from Trans Mountain's initial December 2022 estimate. The budget increase and in service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge Inc. stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline.

In August 2022, the United States District Court for Western Michigan rejected the Attorney General of Michigan's efforts to move the dispute to Michigan state court, citing important federal interests at stake in having the dispute heard in federal court. Michigan's Attorney General intends to appeal the decision.

In September 2022, the District Court of Wisconsin ruled in favour of the Bad River Band in its dispute with Enbridge Inc. over the Enbridge Line 5 pipeline system in that state. Stopping short of ordering the system to be shut down, the court ruled that the Bad River Band is entitled to financial compensation, and ordered Enbridge Inc. to reroute the pipeline around Bad River territory within five years.

Marine Tankers

The *Oil Tanker Moratorium Act* (Canada), which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium.

Natural Gas and LNG

Natural gas prices in Western Canada have 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 infrastructure 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 is generally lower than the prices received in other North American markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation received federal approval to expand the Nova Gas Transmission Line system (the "**NGTL System**") and the expanded NGTL System was completed in April 2022.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of December 2021, construction of the CGL Pipeline is approximately 60% complete.

In addition to LNG Canada and the CGL Pipeline projects, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most importantly, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement

("**NAFTA**") on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could have an impact on Western Canada's oil and gas industry at large, including the Corporation's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia and Europe.

Canada is also party to the CETA, which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Following the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada entered into the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"), which replicates CETA on a bilateral basis to maintain the status quo of the Canada-United Kingdom trade relationship.

While it is uncertain what effect CETA, CUKTCA or any other trade agreements will have on the petroleum 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

Mineral Rights

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits (collectively, "**leases**") for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

All 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 disposition. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licenses.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned 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 companies seeking to explore for and/or develop oil and natural gas reserves.

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 manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations through *An Act to Amend the Indian Oil and Gas Act* and the accompanying regulations. The Corporation does not have operations on Indigenous reserve lands.

Surface Rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage. Similar rules apply to facility and pipeline operators.

Royalties and Incentives

General

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable.

Producers and working interest owners of oil and natural gas rights may create additional royalties or royalty-like interests, such as overriding royalties, net profits interests and net carried interests, through private transactions, the terms of which are subject to negotiation.

Occasionally, the provincial governments in Western Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

In addition, from time to time, including during the COVID-19 pandemic, the federal government creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry as well as other industries in Canada.

Alberta

Crown Royalties

In Alberta, 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.

In 2016, the Government of Alberta adopted a modernized Crown royalty framework (the "**Modernized Framework**") that applies to all conventional oil (i.e., not oil sands) and natural gas wells drilled after December 31, 2016 that produce Crown-owned resources. The previous royalty framework (the "**Old Framework**") will continue to apply to wells producing Crown-owned resources that were drilled prior to January 1, 2017 until December 31, 2026, following which time they 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.

Royalties on production from wells subject to the Modernized Framework are determined on a "revenue-minus-costs" basis. The cost component is based on a Drilling and Completion Cost Allowance formula that relies, in part, on the industry's average drilling and completion costs, determined annually by the Alberta Energy Regulator (the "**AER**"), and incorporates information specific to each well such as vertical depth and lateral length.

Under the Modernized Framework, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable Drilling and Completion Cost Allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%.

Under the Old Framework, royalty rates for conventional oil production can be as high as 40% and royalty rates for natural gas production can be as high as 36%. Similar to the Modernized Framework, these rates vary based on the nature of the resource and market prices. The natural gas royalty formula also provides for a reduction based on the measured depth of the well, as well as the acid gas content of the produced gas.

In addition to royalties, producers of oil and natural gas from Crown lands in Alberta are also required to pay annual rentals to the Government of Alberta.

Freehold Royalties and Taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner.

The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

Incentives

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 coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Regulatory Authorities and Environmental Regulation

General

The Canadian oil and gas industry is 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 oil and 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 licenses and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and greenhouse gas ("**GHG**") emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO2e**")), may impose further requirements on operators and other companies in the oil and gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

The CERA and the *Impact Assessment Act* (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the Impact Assessment Agency (the "**IA Agency**") or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75 kilometres of new rights of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related statutes 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 Government of Alberta relies on regional planning to accomplish its 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. 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 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.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and natural gas production. The Corporation routinely conducts hydraulic fracturing in its drilling and completion programs. In recent years, hydraulic fracturing has been linked to increased seismicity in certain areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place are Fox Creek, Red Deer and Brazeau (the "**Seismic Protocol Regions**"). The Corporation does have operations in these regions. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

Liability Management

Alberta

The AER administers the Liability Management Framework (the "**AB LM Framework**") and the Liability Management Rating Program (the "**AB LMR Program**") to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AB LM Framework. This change was effected under key new AER directives in 2021. Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the AB LM Framework include a new Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program ("**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effect, including the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LF Program**") and elements of the Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under the AB LM Framework and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

Complementing the AB LM Framework and 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 the AB OWL Program fund the Orphan Fund through a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB LF Program. 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.

The Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision), provides the backdrop for Alberta's approach to liability management. As a result of the Redwater decision, 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 licence transfer when any such licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed the *Liabilities Management Statutes Amendment Act*, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the

Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. These changes came into force in June 2020.

One important step in the shift to the AB LM Framework has been amendments to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities. All licence transfers and granting of new well, facility and pipeline licences in Alberta are subject to AER approval. Previously under the AB LMR Program, as a condition of transferring existing AER licences, approvals and permits, all transfers required transferees to demonstrate that they had a liability management rating of 2.0 or higher immediately following the transfer. If transferees did not have the required rating, they would have to otherwise prove to the satisfaction of the AER that they could meet their abandonment and reclamation obligations, through means such as posting security or reducing their existing obligations. However, amendments from April 2021 to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

Alongside changes to Directive 067, the AER also introduced *Directive 088: Licensee Life-Cycle Management* ("**Directive 088**") in December 2021 under the AB LM Framework. Directive 088 replaces, to an extent, the AB LLR Program with the AB LCA. Whereas the AB LLR Program previously assessed a licensee based on a liability rating determined by the ratio of a licensee's deemed asset value relative to the deemed liability value of its oil and gas wells and facilities, the AB LCA now considers a wider variety of factors and is intended to be a more comprehensive assessment of corporate health. Such factors are wide reaching and include: (i) a licensee's financial health; (ii) its established total magnitude of liabilities, (iii) the remaining lifespan of its mineral resources; (iv) the management of its operations; (v) the rate of closure activities for its liabilities; and (vi) its compliance with administrative and regulatory requirements. These various factors then feed into a broader holistic assessment of a licensee under the AB LM Framework. In turn, that holistic assessment provides the basis for assessing risk posed by licence transfers, as well as any security deposit that the AER may require from a licensee in the event that the regulator deems a licensee at risk of not being able to meet its liability obligations. However, the liability management rating under the AB LLR Program is still in effect for other liability management programs such as the AB OWL Program and the AB LF Program, and will remain in effect until a broadened scope of Directive 088 is phased in over time.

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target.

The Government of Alberta followed the announcement of the AB LM Framework with amendments to the *Oil and Gas Conservation Rules* and the *Pipeline Rules* in late 2020. The changes to these rules fall into three principal categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. In 2018, for example, the AER announced a voluntary area-based closure ("**ABC**") program. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The Corporation is currently participating in the voluntary ABC program.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. 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 changes 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. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing the export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. 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 output-based pricing system ("**OBPS**") for large industry (enabled by the *Output-Based Pricing System Regulations*) and a fuel charge (enabled by the *Fuel Charge Regulations*), both of which impose a price on **CO2e** emissions. This system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by $10 per year until it reaches a maximum price of $50/tonne of CO2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Starting April 1, 2022, the minimum price permissible under the GGPPA is $50/tonne of CO2e.

In addition, on March 5, 2021, the federal government introduced for comment the *Greenhouse Gas Offset Credit System Regulations (Canada)* (the "**Federal Offset Credit Regulations**"). The proposed Federal Offset Credit Regulations are intended to establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS. The final Federal Offset Credit Regulations are currently targeted for publication in mid-2022. While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

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 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 the intentional venting of methane and ensure that 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. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

The federal government has enacted the *Multi-Sector Air Pollutants Regulation* under the authority of the *Canadian Environmental Protection Act, 1999*, which regulates certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced the $750 million Emissions Reduction Fund ("**ERF**"), intended to help the oil and gas sector to reduce the production of methane and other GHG emissions. Funds disbursed through the ERF will primarily take the form of repayable contributions to onshore and offshore oil and gas firms. Of the $750 million in funding, $675 million was allocated to the Onshore Deployment Program, while $75 million was dedicated to the Offshore Deployment Program and the Offshore RD&D (research, development and demonstration) Program. Natural Resources Canada expects that all funding for onshore projects will be allocated by March 2022, while funding for offshore projects will be allocated by March 2023.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis, to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The *Canadian Net-Zero Emissions Accountability Act* (the "**CNEAA**") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and Crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date it came into force.

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. The federal government has indicated that urgent steps are necessary to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050.

Alberta

In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed. The delay in drafting these regulations has been inconsequential thus far, as Alberta's oil sands emit roughly 70 megatonnes of GHG emissions per year, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On April 1, 2022, the carbon tax payable in Alberta will increase from $40 to $50 per tonne of CO2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. In December 2019, the federal government approved Alberta's *Technology Innovation and Emissions Reduction* ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous *Carbon Competitiveness Incentives Regulation*. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. The Corporation was accepted to the TIER program in December 2019, and remains a participant of the program for 2022. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports. 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.

On September 1, 2020, the Government of Alberta announced $750 million in spending from the TIER fund to support projects that help industries reduce their carbon emissions. Such projects include CCUS, energy efficiency, and increased methane management initiatives. An additional $176 million in spending from the TIER fund was announced for similar GHG reduction projects on November 1, 2021.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* ("**Directive 060**"). The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"). The Progress Report provides that, as of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP, consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and the UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward, but has confirmed that the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act.

On June 29, 2021, the British Columbia Supreme Court issued a judgement in *Yahey v British Columbia* (the "**Blueberry Decision**"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("**BRFN**") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. Going forward, the Blueberry Decision may have significant impacts on the regulation of industrial activities in northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties.

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nations Implementation Agreement (the "**BRFN Agreement**"). The BRFN Agreement aims to address cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a $200-million restoration fund by June 2025, an ecosystem-based management approach for future land use planning in culturally important areas, limits on new petroleum and natural gas development, and a new planning regime for future oil and gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on petroleum and natural gas revenue sharing and provincial royalty revenue sharing in the next two fiscal years.

The BRFN Agreement has acted as a blueprint for other agreements between the Government of British Columbia and Indigenous groups in Treaty 8 territory. In late January 2023, the Government of British Columbia and four Treaty 8 First Nations – Fort Nelson, Salteau, Halfway River and Doig River First Nations – reached consensus on a collaborative approach to land and resource planning (the "**Consensus Agreement**"). The Consensus Agreement implements various initiatives including a "cumulative effects" management system linked to natural resource landscape planning and restoration initiatives, new land use plans and protection measures, and a new revenue sharing approach to support the priorities of Treaty 8 First Nations communities.

In July 2022, Duncan's First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by the BRFN. Duncan's First Nation claims in its lawsuit that Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation's treaty rights. The long-term impacts of the Blueberry Decision and the Duncan's First Nation lawsuit on the Canadian oil and gas industry remain uncertain.

Petrus and the Environment

Petrus is committed to meeting its responsibilities to protect the environment wherever we operate. Petrus anticipates that our expenditures, both capital and expense in nature, will continue to increase as a result of operational growth and/or the introduction of new and enhanced legislation relating to the protection of the environment. Petrus will be taking such steps as are required to ensure continued compliance with applicable environmental legislation in each jurisdiction in which we operate. Petrus believes that we are currently in compliance with applicable environmental laws and regulations in all material respects. Petrus also believes that it is likely that the trend towards heightened and additional standards in environmental legislation and regulation will continue.

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 and business interruption insurance on certain properties 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.

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 may be volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, OPEC actions, inflation, political uncertainties, sanctions imposed on certain oil producing nations by other countries and conflicts in the Middle East. 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"*.

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, interest rates 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 political and social events and decisions made in Canada and elsewhere

The Corporation's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact the Corporation's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licenses and permits for the Corporation's activities or restrict the operation of third party infrastructure that the Corporation relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact the Corporation's results.

Other government and political factors that could adversely affect the Corporation's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Corporation's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for the Corporation's products.

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. The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Corporation's activities. See "***Industry Conditions –*** *Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions –* ***Transportation Constraints and Market Access***".

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 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 – Regulatory Authorities and Environmental Regulation - Liability Management*" 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, Trucking 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 truck and 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, trucking and railway lines. 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.

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 hydrocarbons 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 have 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"*.

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. The Corporation's operations are dependent upon the availability of water and its ability to dispose of produced water from drilling and production activities.

Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of oil, liquids and natural gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing have resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity or completely banning hydraulic fracturing in other areas. 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, liquids and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions or bans on hydraulic fracturing in the areas where the Corporation operates could result in the Corporation being unable to economically recover its oil and gas reserves and reserves, which would result in a significant decrease in the value of the Corporation's assets.

Water is an essential component of the Corporation's drilling and hydraulic fracturing processes. Limitations or restrictions on the Corporation's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Corporation is unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on its financial condition, results of operations, and cash flows.

In addition, the Corporation must dispose of the fluids produced from oil, liquids and natural gas production operations, including produced water, which it does directly or through the use of third party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Corporation or by commercial disposal well vendors that the Corporation may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Corporation or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Corporation or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Corporation's business, financial condition, and results of operations.

Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau and Red Deer. Since 2015, the AER has introduced seismic protocols for hydraulic fracturing operators in the Fox Creek, Red Deer and Brazeau areas initially in response to significant induced seismic activity in the Duvernay formation in Fox Creek in February 2015. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude, which vary, among the three regions. The reporting requirements include 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, depending on the magnitude of an earthquake. Orders imposed by the AER in response to seismic events remain in effect as long as the AER deems them necessary. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, leading to continued monitoring by the AER. The AER may extend seismic protocols to other areas of the province if necessary.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – General - Alberta*".

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.

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 – Regulatory Authorities and Environmental 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.

Climate Change

Climate change concerns could result in increased operating costs and reduced demand for the Corporation's products and shares, while the potential physical effects of climate change could disrupt the Corporation's production and cause it to incur significant costs in preparing for or responding to those effects.

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations.

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, 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, liquids, natural gas and related products, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including the Corporation, for alleged personal injury, property damage, or other potential liabilities. While the Corporation is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavourable ruling in any such case could adversely affect the demand for and price of securities issued by the Corporation, impact its operations and have an adverse impact on its financial condition.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG-intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to oil and natural gas and related infrastructure businesses and projects. The impact of such efforts requires the Corporation's management to dedicate significant time and resources to these climate change-related concerns, may adversely affect the

Corporation's operations, the demand for and price of the Corporation's securities and may negatively impact the Corporation's cost of capital and access to the capital markets.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51-107 – *Disclosure of Climate-Related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If the Corporation is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Physical risks

Based on the Corporation's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the Corporation's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. 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.

Inflation and Cost Management

A failure to secure the services and equipment necessary to the Corporation's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Corporation's financial performance and cash flows

The Corporation's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The Corporation's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows.

The cost or availability of oil and gas field equipment may adversely affect the Corporation's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to the Corporation's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Corporation's financial performance and cash flows.

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 may 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.

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 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 New Credit Facilities could result in restricted access to additional capital or being required to repay all amounts owing thereunder

The Corporation currently has the New Credit Facilities and the amount authorized under the ATB Facility is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under the New Credit Facilities 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 New Credit Facilities, 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 New Credit Facilities 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 lender under the ATB Facility uses the Corporation's reserves, commodity prices, applicable discount rate and other factors to determine periodically the Corporation's borrowing base. Any decrease in 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 the New 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 the New 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 the New 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

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.

The Corporation's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the Corporation to decide to reduce or possibly eliminate, coverage. In addition, insurance is purchased from a number of third party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the Corporation's overall risk exposure could be increased and the Corporation could incur significant costs.

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 from 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. 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 hydrocarbon 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 hydrocarbons 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.

Dilution

The Corporation may issue additional Common Shares or other dilutive securities, 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 Land and Rights Claims

Opposition by Indigenous groups to the conduct of the Corporation's operations, development or exploratory activities may negatively impact the Corporation.

Opposition by Indigenous groups to the conduct our operations, development or exploratory activities in any of the jurisdictions in which the Corporation conducts business may negatively impact it in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact the Corporation's progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. Although there are no Indigenous and treaty rights claims on lands where the Corporation operates**,** no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on its operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Corporation's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, a recent British Columbia Supreme Court decision determined that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nations group in northeast British Columbia breached that group's treaty rights. Going forward, this decision may have significant impacts on the regulation of industrial activities in northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties. The long-term impacts of and associated risks of the decision on the Canadian oil and natural gas industry and the Corporation remain uncertain.

In addition, the federal government has introduced legislation to implement the UNDRIP. Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government are uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements. See "*Industry Conditions – Indigenous Rights*".

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 is 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 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.

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. Despite these efforts, 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.

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.

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 AND REGULATORY ACTIONS

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 were a party or in respect of which any of our properties are or were subject during the year ended December 31, 2022, nor are there any such proceedings known to us to be contemplated.

During the year ended December 31, 2022 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

Other than as set forth under "*Development of our Business – 2021 – General Business Development*" and "*Development of our Business – 2022 – General Business Development*", 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

The only material contract 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 the New Credit Facilities, see "*Development of our Business – 2022 – General Business Development*".

INTERESTS OF EXPERTS

As of December 31, 2022, 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 InSite, 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 InSite. 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 InSite when InSite prepared the report, valuation, statement or opinion in question, or (ii) are to be received by InSite. InSite is not, nor is any director, officer or employee of InSite 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 March 14, 2023 in respect of Petrus' financial statements for the year ended and as at December 31, 2022 and who reviewed the financial statements for the three and nine months ended and as at September 30, 2022. 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 18, 2023. Additional financial information is contained in our financial statements and the related management's discussion and analysis for the year ended December 31, 2022.

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, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, 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, 2022, 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**	**Evaluated**	**Reviewed**	**Total**
InSite Petroleum Consultants Ltd.	December 31, 2022	Canada	-	$589.4 million	-	$589.4 million

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, 2022)*".

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:

InSite Petroleum Consultants Ltd.
Calgary, Alberta Canada

March 14, 2023

(signed) by *"Radu Afilipoaei"*
Radu Afilipoaei
Managing Director

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, 2022 (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, InSite Petroleum Consultants Ltd. ("**InSite**");
- met with InSite to determine whether any restrictions affected the ability of InSite to report without reservation; and
- reviewed the reserves data with management and with InSite.

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 InSite 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) "Ken Gary"	*(signed) "Mathew Wong"*
Ken Gary President & Chief Executive Officer	Mathew Wong Chief Financial Officer, Vice President, Finance
(signed) "Donald Gray"	*(signed) "Donald Cormack"*
Donald Gray Director & Chairman of the Reserves Committee	Donald Cormack Director

March 14, 2023