Annual Information Form

For the Year Ended December 31, 2022
Dated March 8, 2023

Table of Contents

SELECT DEFINITIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this Annual Information Form. Certain other terms and abbreviations used herein, but not defined herein, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended;

"**AIF**" or "**Annual Information Form**" means this annual information form;

"**Audit Committee**" means the audit committee of the Board;

"**Board of Directors**" or "**Board**" means the board of directors of the Corporation;

"**COGE Handbook**" means the "Canadian Oil and Gas Evaluation Handbook" maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time;

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

"**Consolidation**" means the consolidation of the Common Shares on the basis of 8.5 pre-Consolidation Common Shares for each one post-Consolidation Common Share effective August 20, 2021;

"**Corporation**" or "**Surge**" means Surge Energy Inc., a corporation amalgamated under the ABCA;

"**Credit Facilities**" means, collectively, the First Lien Credit Facilities and the Second Lien Term Debt Facility;

"**Debentures**" means the 6.75% convertible unsecured subordinated debentures due on June 30, 2024, as more particularly described under the heading "*Description of Capital Structure*";

"**First Lien Credit Facilities**" means the aggregate $210 million revolving first lien secured credit facilities of the Corporation with a syndicate of lenders;

"**IFRS**" means International Financial Reporting Standards, as issued by the International Accounting Standards Board, as amended from time to time;

"**Indenture**" means the debenture indenture dated May 8, 2019 between Surge and Computershare Trust Company of Canada, as amended on November 15, 2017 and as supplemented by a first supplemental debenture indenture dated May 8, 2019, under which the Debentures were issued;

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

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Requirements*;

"**Reserves Report**" means the independent engineering report with a preparation date of February 15, 2023 and effective December 31, 2022 prepared by and containing the evaluation of Sproule of the oil, NGL and natural gas reserves attributable to the properties of the Corporation;

"**Second Lien Term Debt Facility**" means the approximately $194 million non-revolving second lien secured credit facility of the Corporation;

"**Sproule**" means Sproule Associates Limited, independent oil and gas reservoir engineers;

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

"**U.S.**" or "**United States**" means the United States of America.

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. All dollar amounts set forth in this Annual Information Form, including "dollar", "$" and "CAD$" are in Canadian dollars, except where otherwise indicated. "US$" means United States dollars.

ABBREVIATIONS AND CONVERSION

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
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
bbl/d	barrels per day	Bcf	billion cubic feet
NGLs	natural gas liquids	GJ	gigajoule
stb	stock tank barrel		

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	28.174
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

Other

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 35.1° API or greater is generally referred to as light crude oil. Liquid petroleum with a specified gravity of 25.8° to 35° API or greater is generally referred to as medium crude oil. Liquid petroleum with a specified gravity of 25.7° API or lower is generally referred to as heavy crude oil.

boe	barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
boe/d	barrel of oil equivalent per day
m^3	cubic metres
Mboe	1,000 barrels of oil equivalent
MMboe	1,000,000 barrels of oil equivalent
$000s	thousands of dollars
M$ or $M	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NON-IFRS MEASURES

This AIF contains the term “operating netback” which is not defined by IFRS and therefore may not be comparable to performance measures presented by others. In this AIF, “operating netback” is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. Management believes that in addition to net income, operating netbacks are a useful supplemental measure as it assists in the determination of the Corporation’s operating performance. Readers should be cautioned, however, that this measure should not be construed as an alternative to both net income and net cash from (used in) operating activities, which are determined in accordance with IFRS, as indicators of the Corporation’s performance.

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 estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

The recovery and reserve estimates of oil, NGL 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 the Corporation’s natural gas and petroleum reserves does not represent the fair market value of the Corporation’s reserves.

Caution Respecting Boe

In this AIF, the abbreviation boe means barrel of oil equivalent on the basis of 1 boe 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 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

Definitions

Certain terms used in this AIF in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this AIF, but not defined or described, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

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: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates as follows:

"**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.

"**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.

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.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories as follows:

"**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. The developed category may be subdivided into producing and non-producing as follows:

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

"**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production but are shut-in and the date of resumption of production is unknown.

"**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.

Interests in Reserves, Production, Wells and Properties

"**gross**" means: (i) in relation to an issuer's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the issuer; (ii) in relation to wells, the total number of wells in which an issuer has an interest; and (iii) in relation to properties, the total area of properties in which an issuer has an interest.

"**net**" means: (i) in relation to an issuer's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves; (ii) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (iii) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer.

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

Description of Exploration and Development Wells and Costs

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) 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; (ii) drill, complete 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; (iii) 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 (iv) 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 in part 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: (i) 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 sometimes referred to as "geological and geophysical costs"); (ii) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (iii) dry hole contributions and bottom hole contributions; (iv) costs of drilling, completing and equipping exploratory wells; and (v) 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.

"**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.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements or disclosures contained in this Annual Information Form constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. 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. The Corporation believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form.

In particular, this Annual Information Form may contain forward-looking statements and information pertaining to the following:

- the performance characteristics of the Corporation's oil and natural gas properties;
- oil and natural gas production levels, and expectations of future production rates, volumes and product mixes;
- the size of the oil and natural gas reserves of the Corporation and anticipated future cash flows from such reserves;
- projections of market prices and costs, and exchange and inflation rates;
- 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;
- the Corporation's dividend policy;
- treatment under governmental regulatory regimes and tax and royalty laws;
- criteria and considerations in participations and acquisitions;
- the Corporation's tax horizon;
- timing of development of undeveloped reserves;
- estimated abandonment and reclamation costs and the timing thereof;
- expected land expiries and plans with respect thereto;
- plans to implement enhanced recovery; and
- capital expenditure programs, the allocation of such capital and the timing thereof.

With respect to forward looking statements contained in this Annual Information Form, the Corporation has made assumptions regarding:

- oil and natural gas production levels and the timing of new wells coming on-stream;
- the success of the Corporation's operations and exploration and development activities;
- the size of Surge's oil, natural gas and NGL reserves and the recoverability of its reserves;
- prevailing weather conditions, commodity prices and exchange rates;
- the availability of labour, services and drilling equipment;
- the availability of capital to fund planned expenditures;
- timing and amount of capital expenditures;
- timing of production curtailments;
- future operating costs and future cash flow;
- the Corporation's future debt levels;
- general economic and financial market conditions;
- the Corporation's ability to market production of oil and natural gas successfully to customers;
- the applicability of technologies for recovery and production of the Corporation's reserves;
- the success, nature and timing of water flood activities;
- the ability of the Corporation to secure necessary capital, personnel, equipment and services; and
- government regulation in the areas of taxation, royalty rates and environmental protection.

The actual results, performance or achievements of the Corporation may differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- the impact of pandemics and public health emergencies, including those related to COVID-19 coronavirus and the impacts on field activity levels, health and safety considerations and restrictions which may impact the ability of the Corporation to carry on business as planned;
- the impact of geopolitical actions, including war (including the Russia-Ukraine conflict) and terrorism;
- uncertainties associated with estimating oil and natural gas reserves and production levels;
- uncertainty surrounding the amount that will be available under the Credit Facilities in the future;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- failure to obtain industry partner, regulatory or other third-party consents and approvals, when required;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- fluctuations in the cost of borrowing;
- the marketability of production and demand of Surge's products;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- a decrease or elimination of the payment of dividends by the Corporation as a result of the Board of Directors determination or restrictions under applicable agreements or corporate laws;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- unfavourable weather conditions;
- a failure of the Corporation to hire or retain key personnel;
- incorrect assessments of the value of acquisitions, dispositions and exploration and development programs;

- geological, technical, drilling, completion and processing problems;
- results of water flood responses;
- the outcome of litigation or regulatory proceedings brought against the Corporation or other disputes involving the Corporation;
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry;
- the impact of or natural disasters including earthquakes, typhoons, floods and fires;
- cyber-security issues;
- failure to realize the anticipated benefits of acquisitions and dispositions; and
- the other factors discussed under "*Risk Factors*".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

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. The Corporation does not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

SURGE ENERGY INC.

Corporate Structure

Surge was incorporated on January 26, 1998 under the ABCA as "Zapata Capital Inc." On June 18, 1999, the Corporation acquired all of the issued and outstanding shares of 744997 Alberta Ltd. and amalgamated with 744997 Alberta Ltd. under the name "Zapata Energy Corporation". On June 25, 2010, the Corporation changed its name to "Surge Energy Inc." On December 31, 2010, the Corporation amalgamated with its wholly-owned subsidiary, Breaker Resources Ltd. On December 31, 2012, the Corporation amalgamated with is wholly-owned subsidiary, Surge Oil Inc. On December 31, 2013, the Corporation amalgamated with its wholly-owned subsidiaries, Flagstone Energy Inc. and 1779275 Alberta Ltd. On December 31, 2014, the Corporation amalgamated with its wholly-owned subsidiary, Longview Oil Corp. On December 31, 2018, the Corporation amalgamated with its wholly-owned subsidiary, Mount Bastion Oil & Gas Corp. On August 18, 2021, the Corporation amalgamated with its wholly-owned subsidiary, Surge Acquisition Co Ltd. On August 20, 2021 the Corporation amended its articles to effect the Consolidation. On November 1, 2021, the Corporation amalgamated with its wholly-owned subsidiary, 2385316 Alberta Ltd. On December 31, 2021, the Corporation amalgamated with its wholly-owned subsidiary, 1413942 Alberta Ltd.

The head office of the Corporation is located at Suite 1200, 520 – 3rd Avenue S.W., Calgary, Alberta T2P 0R3. The registered office of the Corporation is located at Suite 4000, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

DEVELOPMENT OF THE BUSINESS

General

The Corporation is an independent oil and gas company based in Calgary, Alberta and operating in Alberta, Saskatchewan and Manitoba. The Common Shares are listed on the TSX under the symbol "SGY". The Debentures are listed on the TSX under the symbols "SGY.DB.A".

Three Year History

Significant developments of the Corporation over the last three completed financial years are as set forth below:

Year ended December 31, 2020

On June 26, 2020, Surge completed the sale of certain non-core assets in Northwest Alberta for aggregate cash proceeds of $5.3 million.

Year Ended December 31, 2021

On March 25, 2021, Surge completed the sale of certain core assets in Northeast Alberta and Southeast Alberta for aggregate proceeds of $106 million.

On August 18, 2021, Surge completed its acquisition of Astra Oil Corp. ("**Astra**") pursuant to a plan of arrangement under the provisions of the ABCA for a purchase price of approximately $160 million. Concurrent with the acquisition of Astra, Surge's fully conforming first lien revolving credit facilities were set at $215 million.

On November 1, 2021, Surge completed its acquisition of Fire Sky Energy Inc. ("**Fire Sky**") following the amalgamation of Fire Sky and a wholly-owned subsidiary of Surge under the provisions of *The Business Corporations Act* (Saskatchewan) for a purchase price of approximately $58 million.

On December 9, 2021, Surge entered into a 5-year, $130 million senior secured Second Lien Term Debt Facility with an annual coupon of 8.85 percent. In conjunction with the entering into of the Second Lien Term Debt Facility, on December 9, 2021, Surge entered into new $150 million first lien credit facilities with a syndicate of lenders.

Year Ended December 31, 2022

On May 5, 2022, Surge received an additional $30 million of term debt financing under its existing Second Lien Credit Facility. Concurrently, Surge reconfirmed and extended its existing First Lien Credit Facilities through to May 31, 2024.

On October 28, 2022 (the "**Redemption Date**"), Surge redeemed all of the outstanding 5.75% convertible unsecured subordinated debentures originally due on December 31, 2022, paying the aggregate principal amount of the such debentures (being $1,000 per debenture) plus all unpaid interest thereon to, but excluding the Redemption Date. These debentures, which had traded on the TSX under the symbol "SGY.DB", were delisted from the TSX on the Redemption Date.

On December 19, 2022, Surge completed an acquisition of crude oil assets in Surge's Sparky and Southeast Saskatchewan core areas from Enerplus Corporation for net proceeds of $198 million (the "**Enerplus Acquisition**"). Concurrent with closing of the Enerplus Acquisition, the Corporation expanded its First Lien Credit Facilities to a total of $210 million and increased its Second-Lien Credit Facilities to approximately $194 million.

Significant Acquisitions

Surge did not complete any "significant acquisitions" (as such term is defined in NI 51-102) during the financial year ended December 31, 2022.

DESCRIPTION OF THE BUSINESS

Overview

The Corporation is an oil and gas exploration, development and production company. Surge holds focused and operated light and medium gravity crude oil properties in Alberta, Saskatchewan and Manitoba, characterized by large oil in place crude oil reservoirs with low recovery factors. The Corporation has a significant inventory of low risk development drilling locations, including several successful water flood projects.

Corporate Strategy

The Corporation focuses on assets with the following criteria: large oil in place with low recovery factors; available infrastructure; high working interest; operatorship; all-season access and drilling inventory; water flood opportunities; and other upside that provides a definable high rate of return.

Management believes in controlling the timing and costs of the Corporation's projects wherever possible. Accordingly, the Corporation seeks to become the operator of its properties. Further, to minimize competition within its geographic areas of interest, the Corporation strives to maximize its working interest ownership in its properties where reasonably possible.

In reviewing potential drilling or acquisition opportunities, the Corporation gives consideration to the following criteria: risk capital to secure or evaluate the opportunity; the potential return on the project, if successful; the likelihood of success; and risked return versus cost of capital.

In general, the Corporation pursues a portfolio approach in developing a large number of opportunities with a balance of risk profiles in an attempt to generate sustainable levels of growth. The Board of Directors of the Corporation may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon the Board's consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

In addition, the management team of the Corporation, as described below under "*Directors and Officers*", is continually assessing the assets and operations of the Corporation, including its existing land base, facilities, reserves, prospects and personnel.

Competition

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

Cyclical and Seasonal Nature of Industry

Surge's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated dramatically during recent years and are determined by a number of factors, including global and local supply and demand factors, and including weather and general economic conditions, as well as conditions in other oil and natural gas producing and consuming regions. Surge attempts to mitigate such price risk through closely monitoring commodity markets and establishing disciplined hedging programs.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain.

Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation. Demand for natural gas typically rises during cold winter months and hot summer months.

Environmental Regulation

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

The Corporation is obligated to abandon, retire and reclaim wells and well sites in compliance with applicable environmental laws and regulations. As of December 31, 2022, the Corporation has recorded an asset retirement obligation of $264 million. The Corporation anticipates that the expenditures necessary to satisfy the asset retirement obligation will be incurred over a period of 20 years, with the majority of the expenditures being incurred from years 2022 to 2042. Other than asset retirement obligations and ordinary course operational expenditures necessary to ensure environmental compliance, the Corporation is not aware of any environmental protection requirement that will impact its capital expenditures, earnings or competitive position in a manner disproportionate to that of its peers in its area of operations.

Marketing

Surge's crude oil and natural gas production are sold primarily through marketing companies at current market prices.

The Corporation uses a variety of derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates as described under "*Statement of Reserves Data – Other Oil and Gas Information – Forward Contracts*". For details of the Corporation's forward contracts in place as at December 31, 2022, see the Corporation's audited annual financial statements for the year ended December 31, 2022, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Hedging*".

Personnel

As at December 31, 2022, the Corporation had 76 head office employees and seven field employees.

Health, Safety and Environmental

Management, employees and contractors are responsible and accountable for the Corporation's overall health, safety and environmental program. Surge operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety.

Surge maintains a safe and environmentally responsible work place and provides training, equipment and procedures to all individuals in adhering to its policies. It also solicits and takes into consideration input from neighbors, communities and other stakeholders in regard to protecting people and the environment.

In 2022 Surge continued its commitment to environmental, social and governance spending initiatives by spending an aggregate of $11.2 million on abandonment activities.

PRINCIPAL PRODUCING PROPERTIES

The Corporation's principal oil and natural gas producing properties are located in Alberta and Saskatchewan and are focused across five core areas: Sparky, Southeast Saskatchewan, Carbonates, Valhalla and Shaunavon. The Corporation additionally holds interests in properties in Manitoba and certain other non-core areas in Alberta and Saskatchewan (referred to collectively as "**Minors**"). A description of each of these properties as at December 31, 2022 is provided below.

Sparky

As at December 31, 2022, Surge's principal properties in the Sparky area included the Sparky assets and the Lloyd/Cummings waterfloods at Giltedge, Silver, and Lakeview. At Sparky, Surge held an average working interest of approximately 81 percent in approximately 90,619 gross (73,253 net) developed acres and an average working interest of approximately 97 percent in approximately 59,129 gross (57,245 net) undeveloped acres. As at December 31, 2022, the Corporation held interests in 710 gross (560 net) oil wells and nine gross (eight net) gas wells producing from formations including, but not limited to, Sparky, Lloydminster, and Cummings. In addition, the Corporation operates multiple oil batteries, providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2022 production in Sparky was approximately 9,200 boe/d (86 percent oil and NGLs).

The Sparky assets are located between Provost and Wainwright in eastern Alberta and western Saskatchewan. Provost and Betty Lake are early-stage primary development properties, while Wainwright, Giltedge, and Sounding Lake are more mature, mostly developed waterflood assets. Production from the Sparky assets is primarily crude oil (86 percent oil and NGLs) ranging from 19° to 28° API.

In 2022, the Corporation drilled 44 gross (36 net) horizontal Sparky oil wells. Of these wells, 35 were on production by year-end 2022 and the remaining well came on production in Q1 2023.

Southeast Saskatchewan

As at December 31, 2022, the Corporation's principal properties in the Southeast Saskatchewan area include but are not limited to the fields of, Viewfield, Minard, Steelman, Pinto, Bryant, Gainsborough, Freda Lake, and Neptune.

These Southeast Saskatchewan properties are primarily located in the Southeast corner of the Province. As at December 31, 2022, these operated properties included an average working interest of approximately 86 percent in approximately 61,643 gross (52,754 net) developed acres and an average working interest of approximately 86 percent in 44,960 gross (38,483 net) undeveloped acres. As at December 31, 2022, the Corporation held interests in 332 gross (260 net) oil wells producing in the Midale, Frobisher, Alida, and Ratcliffe formations. The Corporation's production from this property is weighted 90 percent to light crude oil (greater than 31.1° API) and 10 percent to medium crude oil (22.3° to 31.1° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. This property's fourth quarter 2022 production was approximately 5,900 boe/d (94 percent oil).

In 2022, the Corporation drilled 46 gross (33 net) horizontal, Frobisher and Midale oil wells. Of these wells, 45 were on production by year-end 2022 and the remaining well came on production in Q1 2023.

Carbonates

As at December 31, 2022, Carbonates includes the Corporation's Greater Sawn, Nevis, and Westerose properties. The Corporation's principal properties in the Greater Sawn area included Sawn Lake, Otter and Red Earth (which collectively comprise the Greater Sawn Lake assets). Within Carbonates, Surge held an average working interest of approximately 79 percent in approximately 142,459 gross (112,848 net) developed acres and an average working interest of approximately 76 percent in approximately 72,681 gross (55,481 net) undeveloped acres. As at December 31, 2022, the Corporation held interests in 374 gross (293 net) oil wells and 22 gross (17 net) gas wells producing from formations including, but not limited to, Slave Point, Granite Wash, Gilwood, Wabamun and Banff. In addition, the Corporation operates multiple oil batteries providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2022 production in Carbonates was approximately 2,990 boe/d (91 percent oil and NGLs).

The Greater Sawn Lake assets are comprised of three main fields (Sawn Lake, Otter and Red Earth) near Red Earth Creek in Northern Alberta. Production from this property is primarily 40° API light oil from the Slave Point and Granite Wash formations. The majority of the new development is focused on the Slave Point formation. The majority of these pools are currently on primary production with horizontal Slave Point waterflood being implemented in Sawn Lake. These assets were acquired on October 25, 2018, with the corporate acquisition of Mount Bastion.

Valhalla

As at December 31, 2022, the Corporation's principal property in the Valhalla area is the Valhalla/Wembley property. At Valhalla, Surge held an average working interest of approximately 70 percent in approximately 23,560 gross (16,598 net) developed acres and an average working interest of approximately 73 percent in approximately 10,520 gross (7,642 net) undeveloped acres. As at December 31, 2022, the Corporation held interests in 100 gross (59 net) oil wells and 10 gross (four net) gas wells producing from formations including, but not limited to, Doig and Montney. In addition, the Corporation operates multiple oil batteries providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2022 production in Valhalla was approximately 1,970 boe/d (46 percent oil and NGLs).

The Valhalla/Wembley property is located in northwestern Alberta, approximately 40 kilometres northwest of Grand Prairie. The majority of production from this property was from the horizontal oil wells producing from an extensive tight sand, with up to 40 metres of gross light oil pay in the Triassic Doig formation.

In 2022, the Corporation drilled one gross (0.53 net) horizontal, multi-frac, Doig oil well. This well was on production by December 31, 2022.

Shaunavon

The Shaunavon properties are primarily located approximately 100 kilometres southwest of Swift Current, Saskatchewan and 140 kilometres east of the Alberta border. As at December 31, 2022, these operated properties included an average working interest of approximately 98 percent in approximately 24,086 gross (23,667 net) developed acres and an average working interest of approximately 100 percent in 8,383 gross (8,383 net) undeveloped acres. As at December 31, 2022, the Corporation held interests in 181 gross (181 net) oil wells producing from the Upper and Lower Shaunavon formations, among others. The Corporation's production from this property is weighted 88 percent to medium crude oil (21° to 26° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. This property's fourth quarter 2022 production was approximately 1,130 boe/d (88 percent oil).

Manitoba

As at December 31, 2022, the Corporation's principal properties in the Manitoba area included Sinclair.

The Manitoba properties are primarily located approximately 290 kilometres west of Brandon, Manitoba and east of the Saskatchewan border. As at December 31, 2022, these operated properties included an average working interest of approximately 76 percent in approximately 8,012 gross (6,128 net) developed acres and an average working interest of approximately 100 percent in 1,663 gross (1,663 net) undeveloped acres. As at December 31, 2022, the Corporation held interests in 147 gross (109 net) oil wells producing from the Lodgepole, Bakken, and Torquay. The Corporation's production from this property is weighted 100 percent to medium crude oil (35° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. This property's fourth quarter 2022 production was approximately 570 boe/d (100 percent oil).

Minors

As at December 31, 2022, the Corporation's principal properties include all of the non-core area across Alberta and Saskatchewan. In the minor areas, Surge held an average working interest of approximately 60 percent in approximately 128,881 gross (77,268 net) developed acres and an average working interest of approximately 46 percent in approximately 23,981 gross (11,047 net) undeveloped acres. As at December 31, 2022, the Corporation held interests in 95 gross (57 net) oil wells and 111 gross (11 net) gas wells. This area's fourth quarter 2022 production was approximately 275 boe/d (69 percent oil and NGLs).

STATEMENT OF RESERVES DATA

In accordance with NI 51-101, Sproule prepared the Reserves Report based on its evaluation of the oil, NGLs and natural gas reserves attributable to the properties of the Corporation as at December 31, 2022. The Reserves Report has a preparation date of February 15, 2023.

The tables below are a combined summary of the oil, NGL and natural gas reserves attributable to the properties of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Reserves Report based on forecast price and cost assumptions. The tables summarize the data contained in the Reserves Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

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 costs for only those wells assigned reserves by Sproule.

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

The Reserves Report is based on certain factual data supplied by the Corporation and Sproule's opinions 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 the Corporation to Sproule. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

Summary of Oil and Gas Reserves – Forecast Prices and Costs

	Gross Reserves					Net Reserves				
	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)
Proved										
Developed Producing	24,809	13,036	1,226	32,375	678	21,234	11,371	1,005	29,366	618
Developed Non-Producing	405	1,030	75	1,013	-	364	889	61	950	-
Undeveloped	18,040	13,044	1,433	35,682	80	15,178	11,206	1,192	32,177	76
Total Proved	43,254	27,110	2,734	69,070	758	36,776	23,466	2,258	62,493	694
Probable	18,990	12,442	1,270	31,166	235	15,729	10,527	1,042	27,842	220
Total Proved plus Probable	62,244	39,552	4,004	100,236	993	52,505	33,993	3,300	90,335	914

Net Present Value of Future Net Revenue – Forecast Prices and Costs

	Before Future Income Tax Expenses and Discounted at				
($M)	0%	5%	10%	15%	20%
Proved					
Developed Producing	1,243,817	1,179,669	1,054,718	947,817	862,056
Developed Non-Producing	59,695	48,142	40,225	34,547	30,312
Undeveloped	1,065,684	775,592	580,949	446,498	350,640
Total Proved	2,369,196	2,003,403	1,675,892	1,428,862	1,243,008
Probable	1,625,101	1,126,089	834,910	650,841	526,804
Total Proved plus Probable	3,994,297	3,129,492	2,510,802	2,079,703	1,769,812

	After Future Income Tax Expenses and Discounted at				
($M)	0%	5%	10%	15%	20%
Proved					
Developed Producing	1,200,807	1,148,390	1,031,508	930,286	848,601
Developed Non-Producing	46,181	37,817	32,180	28,174	25,191
Undeveloped	808,051	576,463	422,103	316,626	242,364
Total Proved	2,055,039	1,762,670	1,485,792	1,275,086	1,116,157
Probable	1,245,033	854,536	629,235	488,097	393,707
Total Proved plus Probable	3,300,072	2,617,205	2,115,026	1,763,183	1,509,863

	Unit Value before Income Tax Discounted at 10%/year ($/boe)
Proved	
Developed Producing	27.32
Developed Non-Producing	27.34
Undeveloped	17.63
Total Proved	22.95
Probable	26.11
Total Proved plus Probable	23.91

Additional Information Concerning Future Net Revenue – Forecast Prices and Costs (Undiscounted)

(Undiscounted) ($M)	Revenue	Royalties	Operating Costs	Develop-ment Costs	Abandon-ment and Other Costs	Future net revenue before income taxes	Future income taxes	Future net revenue after income taxes
Total Proved	7,136,541	1,018,338	2,579,969	846,114	322,924	2,369,196	314,157	2,055,039
Total Proved plus Probable	10,526,579	1,564,721	3,554,113	1,075,195	338,252	3,994,297	694,225	3,300,072

Future Net Revenue by Production Group – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes and Discounted at 10% per year ($M)	Per Unit Future Net Revenue Before Income Taxes and Discounted at 10%[3] per year ($/boe)
Proved		
Light and Medium Crude Oil[1]	1,025,228	22.23
Heavy Crude Oil[1]	640,519	24.49
Conventional Natural Gas[2]	9,547	14.84
Coalbed Methane[2]	598	5.17
Proved plus Probable		
Light and Medium Crude Oil[1]	1,551,171	23.54
Heavy Crude Oil[1]	947,849	24.85
Conventional Natural Gas[2]	11,062	13.73
Coalbed Methane[2]	720	4.73

Notes:

1. Including solution gas and other by-products.
2. Including by-products, but excluding solution gas from oil wells.
3. Based on net reserves volumes.

Pricing Assumptions – Forecast Prices and Costs

Sproule employed the following pricing and inflation rate assumptions as of December 31, 2022 in its evaluation in estimating reserves data using forecast prices and costs. The weighted average historical prices received by the Corporation for 2022 are also reflected in the table below.

	Medium and Light Crude Oil		Natural Gas	NGL					
Year	Canadian Light Sweet Crude 40 API ($/bbl)	Western Canada Select 20.5 API ($/bbl)	Alberta AECO Gas Price ($/MMBtu)	Edmonton Pentanes plus ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Propane ($/bbl)	Operating Cost Inflation rates (%/Yr)	Capital Cost Inflation rates (%/Yr)	Exchange rate ($US/$Cdn)
2022 (Historic)	119.73	101.64	5.43	121.28	61.68	50.11	8.6%	11.2%	0.77
2023	110.67	88.00	4.33	114.67	54.47	38.13	0.0%	0.0%	0.75
2024	101.25	89.38	4.34	105.00	52.50	37.28	3.0%	3.0%	0.80
2025	96.18	84.06	4.00	100.00	50.00	37.68	2.0%	2.0%	0.80
2026	98.10	85.74	4.08	102.00	51.00	38.44	2.0%	2.0%	0.80
2027	100.06	87.46	4.16	104.04	52.02	39.21	2.0%	2.0%	0.80
2028	102.06	89.21	4.24	106.12	53.06	39.99	2.0%	2.0%	0.80
2029	104.10	90.99	4.33	108.24	54.12	40.79	2.0%	2.0%	0.80
2030	106.18	92.81	4.42	110.41	55.20	41.61	2.0%	2.0%	0.80
2031	108.31	94.67	4.50	112.62	56.31	42.44	2.0%	2.0%	0.80
2032	110.47	96.56	4.59	114.87	57.43	43.29	2.0%	2.0%	0.80
2033	112.68	98.49	4.68	117.17	58.58	44.16	2.0%	2.0%	0.80

Note:

1. Escalated thereafter at a rate of +2.0% per annum.

Reconciliation of Changes in Reserves

The following table sets forth a combined reconciliation of the Corporation's gross reserves as at December 31, 2022, derived from the Reserves Report using forecast prices and cost estimates, reconciled to the gross reserves of the Corporation as at December 31, 2022.

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Boe (Mboe)
Proved						
Balance at December 31, 2021	38,017	20,419	3,302	68,289	255	73,161
Product Type Transfer						
Extensions and Improved Recovery	720	1,197	26	1,213	-	2,145
Infill Drilling	2,048	731	143	1,228	-	3,126
Technical Revisions	(967)	(2,022)	(793)	(4,170)	278	(4,430)
Acquisitions	5,713	7,329	50	1,706	-	13,377
Dispositions	(6)	(1)	(0)	(1)	-	(7)
Economic Factors	2,355	1,185	265	7,619	290	5,124
Production	(4,627)	(1,729)	(258)	(6,814)	(64)	(7,760)
Balance at December 31, 2022	43,253	27,109	2,735	69,070	759	84,736

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Boe (Mboe)
Probable						
Balance at December 31, 2021	15,981	9,919	1,455	29,209	73	32,236
Product Type Transfer						
Extensions and Improved Recovery	904	605	81	2,683	-	2,037
Infill Drilling	506	608	17	117	-	1,150
Technical Revisions	211	(954)	(257)	761	92	(857)
Acquisitions	1,460	2,282	18	679	-	3,873
Dispositions	(176)	(0)	(0)	(0)	-	(177)
Economic Factors	103	(18)	(44)	(2,282)	70	(328)
Production	-	-	-	-	-	-
Balance at December 31, 2022	18,989	12,442	1,270	31,167	235	37,934

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Boe (Mboe)
Proved plus Probable						
Balance at December 31, 2021	53,998	30,338.1	4,757	97,500	327	105,397
Product Type Transfer						
Extensions and Improved Recovery	1,625	1,802	107	3,896	-	4,182
Infill Drilling	2,554	1,339	159	1,345	-	4,276
Technical Revisions	(755)	(2,976)	(1,049)	(3,409)	369	(5,287)
Acquisitions	7,173	9,612	67	2,384	-	17,250
Dispositions	(182)	(1)	(0)	(1)	-	(183)
Economic Factors	2,458	1,167	221	5,336	360	4,796
Production	(4,627)	(1,729)	(258)	(6,814)	(64)	(7,760)
Balance at December 31, 2022	62,244	39,552	4,004	100,237	992	122,671

Additional Information Relating to Reserves Data

First Attributed Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were first attributed in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)
Proved				
2020	674	795	21	1,587
2021	5,576	2,529	472	3,541
2022	2,231	3,479	129	2,102

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)
Probable				
2020	537	673	20	1,435
2021	4,037	1,720	324	3,541
2022	1,871	2,651	133	3,725

Proved 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. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

The Corporation currently plans to pursue the development of its proven and probable undeveloped reserves within the next two years through ordinary course capital expenditures. However, the Corporation may choose to delay development depending on a number of circumstances, including the existence of higher priority expenditures and prevailing commodity prices and cash flow.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

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

	Forecast Prices and Costs	
	Proved Reserves ($M)	**Proved plus Probable Reserves ($M)**
2023	126,014	152,637
2024	219,789	238,990
2025	200,200	231,641
2026	153,418	222,531
2027	102,979	162,606
Remaining Years	43,713	66,790
Total Undiscounted	846,113	1,075,195

The Corporation has four sources of funding available to finance its capital expenditure programs: internally generated cash flow from operations, funds raised from the sale of non-core assets, debt financing when appropriate and new issues of Common Shares, if available on favourable terms. The Corporation expects to fund the above future development costs primarily through internally generated cash flow, funds raised from the sale of non-core assets and debt. There can be no guarantee that the Board of Directors will allocate funding to develop all of the reserves attributed in the Reserves Report. Failure to develop those reserves could have a negative impact on the Corporation's future cash flow.

Other Oil and Gas Information

Oil and Gas Wells

The following table sets forth the number and status of the wells comprising the Assets effective December 31, 2022.

	Active								**Inactive**							
	Oil		**Natural Gas**		**Coalbed Methane**		**Water Inj/Disp**		**Oil**		**Natural Gas**		**Coalbed Methane**		**Water Inj/Disp**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	1,345	1,036	145	33	7	4	335	218	639	449	128	81	-	-	77	48
Saskatchewan	606	532	74	4	-	-	106	98	190	107	7	2	-	-	39	10
Manitoba	-	-	-	-	-	-	5	5	150	113	-	-	-	-	-	-
BC	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,951	1,568	220	38	7	4	446	321	979	669	135	83	-	-	116	58

	Abandoned							
	Oil		Natural Gas		Coalbed Methane		Water Inj/Disp	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,555	1,292	953	834	1	1	218	178
Saskatchewan	146	103	11	8	-	-	16	8
Manitoba	11	11	-	-	-	-	-	-
BC	1	-	-	-	-	-	-	-
Total	1,713	1,406	964	842	1	1	234	186

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2022, the gross and net acres of unproved properties in which the Corporation has an interest and also the number of net acres for which the Corporation's rights to explore, develop or exploit will, absent further action, expire within one year.

	Gross Undeveloped Acres	Net Undeveloped Acres	Net Undeveloped Acres Expiring within One Year
Alberta	140,649	112,691	2,560
Saskatchewan	66,057	52,652	8,600
Manitoba	1,663	1,663	-
BC	-	-	-
Total	208,369	167,006	11,160

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation typically estimates well abandonment costs area by area. Such costs are included in the Reserves Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the Reserves Report for 5,178 net wells under the proved reserves category is $322.9 million undiscounted ($65.7 million discounted at 10 percent), of which a total of $18.3 million is estimated to be incurred in 2024, 2025 and 2026. This estimate includes expected reclamation costs for surface leases which have existing wells with economic developed reserves assigned or future development drilling locations. The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Subject to pending changes in applicable regulations regarding the abandonment and reclamation, ongoing environmental obligations are expected to be funded out of cash flow.

Forward Contracts

Surge is 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 Surge to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. Surge is exposed to losses in the event of default by the counterparties to these derivative instruments. Surge manages this risk by diversifying its derivative portfolio amongst a number of financially sound counterparties.

For details of the Corporation's forward contracts in place as at December 31, 2022, see the Corporation's audited annual financial statements for the year ended December 31, 2022, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Hedging*".

Tax Horizon

Based on planned capital expenditures and the forecast commodity pricing employed in the Reserves Report, the Corporation estimates that it will not be required to pay current income taxes before 2025.

Costs Incurred

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

	Property Acquisition Costs				
	Proved Properties	Unproved Properties	Property Dispositions	Exploration Costs	Development Costs
Total ($M)	-	-	200,270	-	169,944

Drilling Activity

The following table sets forth the gross and net exploration and development wells drilled by the Corporation based on rig release date during the year ended December 31, 2022.

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	83.00	69.10
Heavy Crude Oil	-	-	-	-
Conventional Natural Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
Total	-	-	83.00	69.10

Planned Capital Expenditures

The Corporation has announced a planned capital expenditure budget of approximately $175 million for 2023.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Reserves Report for 2022 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Coalbed Methane (Mcf/d)	Natural Gas Liquids (bbls/d)	Boe (boe/d)	%
Proved							
Carbonates	2,816	-	1,387	284	93	3,188	12%
Valhalla	985	-	8,087	-	279	2,612	10%
Sparky	3,296	6,497	6,599	-	102	10,995	43%
Shaunavon	-	913	693	-	20	1,048	4%
SE Saskatchewan	6,217	-	2,366	-	284	6,895	27%
Manitoba	750	-	-	-	-	750	3%
Minors	129	52	503	-	19	284	1%
Total Proved	14,193	7,462	19,635	284	797	25,772	100%

Proved Plus Probable							
Carbonates	3,089	-	1,418	290	109	3,482	12%
Valhalla	1,087	-	8,710	-	301	2,839	10%
Sparky	3,506	7,266	7,301	-	112	12,100	42%
Shaunavon	-	942	717	-	21	1,082	4%
SE Saskatchewan	7,290	-	2,914	-	353	8,129	28%
Manitoba	855	-	-	-	-	855	3%
Minors	140	53	519	-	20	300	1%
Total Proved Plus Probable	15,967	8,261	21,579	290	916	28,787	100%

Production History

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

Average Daily Production Volume

	Three Months Ended			
	Mar 31, 2022	**Jun 30, 2022**	**Sep 30, 2022**	**Dec 31, 2022**
Conventional Natural Gas (Mcf/d)	18,592	18,565	18,561	19,647
Light and Medium Crude Oil (bbls/d)	16,760	17,110	17,639	18,127
NGL (bbls/d)	691	799	647	695
Coalbed Methane (Mcf/d)	232	195	126	149
Total (boe/d)	20,588	21,035	21,400	22,121

Prices Received, Royalties Paid, Production Costs and Operating Netback – Crude Oil

	Three Months Ended			
($ per Bbl)	**Mar 31, 2022**	**Jun 30, 2022**	**Sep 30, 2022**	**Dec 31, 2022**
Prices Received	90.69	110.30	90.29	80.69
Royalties Paid	(15.33)	(19.75)	(17.20)	(13.51)
Production Costs	(19.15)	(19.01)	(19.21)	(20.85)
Transportation Costs	(1.49)	(1.62)	(1.30)	(1.40)
Operating Netback(1)	54.72	69.92	52.58	44.93

Note:
1. Including solution gas and associated natural gas liquids revenue.

Prices Received, Royalties Paid, Production Costs and Operating Netback – Conventional Natural Gas

	Three Months Ended			
($ per Mcf)	**Mar 31, 2022**	**Jun 30, 2022**	**Sep 30, 2022**	**Dec 31, 2022**
Prices Received	4.56	6.86	5.21	5.24
Royalties Received	(0.19)	0.06	(0.40)	0.04
Production Costs	(0.80)	(0.89)	(0.59)	(0.78)
Transportation Costs	(0.04)	-	0.01	-
Operating Netback	3.53	6.03	4.23	4.50

Prices Received, Royalties Paid, Production Costs and Operating Netback – Combined

	Three Months Ended			
($ per boe)	Mar 31, 2022	Jun 30, 2022	Sep 30, 2022	Dec 31, 2022
Prices Received	91.45	111.44	91.16	81.56
Royalties Paid	(15.36)	(19.74)	(17.27)	(13.50)
Production Costs	(19.28)	(19.16)	(19.31)	(20.98)
Transportation Costs	(1.50)	(1.62)	(1.30)	(1.40)
Operating Netback[(1)]	55.31	70.92	53.28	45.68

Note:

1. Operating Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging.

Production Volume by Field

The following table indicates the average daily net production from the Corporation's important fields for the year ended December 31, 2022.

Field	Light and Medium Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Coalbed Methane (Mcf/d)	Boe (boe/d)	%
Greater Sawn	2,859	1,725	101	-	3,247	15%
Valhalla	925	6,811	167	-	2,227	11%
Sparky	7,643	6,898	121	-	8,913	42%
Shaunavon	1,068	834	25	-	1,232	6%
Minors	194	372	15	175	300	1%
SE Saskatchewan	4,115	2,030	279	-	4,732	22%
Manitoba	610	-	-	-	610	3%
Total	17,414	18,670	708	175	21,261	100%

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. The following is a summary of the rights, privileges, restrictions and conditional attributed to the Common Shares, preferred shares and Debentures.

Common Shares

The holders of Common Shares are entitled to: (i) one vote for each Common Share held at all meetings of shareholders of the Corporation other than meetings of the holders of any class or series of shares meeting as a class or series; (ii) receive any dividends declared by the Corporation on the Common Shares; and (iii) subject to the rights of shares ranking prior to the Common Shares, to receive the remaining property of the Corporation on dissolution, after the payment of all liabilities.

Preferred Shares

Preferred shares may be issued in one or more series. The Board of Directors is authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series. Preferred shares of the Corporation are entitled to a priority over the Common Shares with respect to the payment of dividends and the distribution of assets upon the liquidation, dissolution or winding-up of the Corporation.

Debentures

The Debentures were issued under and pursuant to the provisions of the Indenture among Computershare Trust Company of Canada and Surge.

The following is a summary of the material attributes and characteristics of the outstanding Debentures. This summary does not purport to be complete and is subject to and qualified in its entirety by reference to the terms of the Indenture which may be viewed under Surge's profile on SEDAR at www.sedar.com.

The Debentures are direct, subordinated, unsecured obligations of the Corporation, subordinated to any existing and future senior indebtedness of the Corporation and ranking equally with one another and with all other existing and future subordinated unsecured indebtedness of the Corporation to the extent subordinated on the same terms.

The Debentures will mature and be repayable on June 30, 2024 (the "**Debenture Maturity Date**") and will accrue interest at the rate of 6.75% per annum payable semi-annually in arrears on December 31 and June 30 of each year (each a "**Debenture Interest Payment Date**"), commencing on December 31, 2019 and computed on the basis of a 365-day year. Interest on the Debentures will be payable in lawful money of Canada.

At the holder's option, the Debentures may be converted into Common Shares at any time prior to 5:00 p.m. (Calgary time) on the earlier of the business day immediately preceding (i) the Debenture Maturity Date; and (ii) if called for redemption, the date fixed for redemption by the Corporation. The conversion price of the Debentures was adjusted following the Consolidation to $19.125 per Common Share, subject to further adjustment on certain events (the "**Debenture Conversion Price**"). This represents a conversion rate of approximately 52.2876 Common Shares for each $1,000 principal amount of Debentures, subject to certain anti-dilution provisions. Holders who convert their Debentures will receive, in addition to the applicable number of Common Shares, accrued and unpaid interest in respect thereof for the period up to, but excluding, the date of conversion from, and including, the most recent Debenture Interest Payment Date. If a holder elects to convert its Debentures in connection with a change of control that occurs prior to the Debenture Maturity Date, the holder will be entitled to receive additional Common Shares as a make-whole premium on conversion in certain circumstances (as more fully described in the Indenture).

Prior to June 30, 2023, the Debentures may be redeemed by the Corporation, in whole or in part, from time to time, on not more than 60 days and not less than 30 days prior written notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption, provided that the volume weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days prior to the date on which notice of redemption is provided is at least 125 percent of the Conversion Price. On or after June 30, 2023 and prior to the Debenture Maturity Date, the Debentures may be redeemed by the Corporation, in whole or in part, from time to time, on not more than 60 days and not less than 30 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption.

The Debentures are listed and posted for trading on the TSX under the symbol “SGY.DB.A”.

DIVIDEND POLICY

The Credit Facilities contain certain restrictions on Surge’s ability to pay dividends. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, a corporation must be able to pay its liabilities as they become due and the realizable value of the assets of the corporation must be greater than the liabilities and the legal stated capital of its outstanding securities.

The following monthly cash dividends on Common Shares were declared in respect of the periods indicated:

	Dividends per Common Share ($)		
Month	**2022**	**2021**	**2020**
January	-	-	0.008333
February	-	-	0.008333
March	-	-	0.000833
April	-	-	-
May	-	-	-
June	0.035	-	-
July	0.035	-	-
August	0.035	-	-
September	0.035	-	-
October	0.035	-	-
November	0.035	-	-
December	0.035	-	-
Total	**0.245**	**-**	**0.017499**

Unless otherwise specified, all dividends paid are designated as “eligible dividends” under the *Income Tax Act* (Canada).

The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and will otherwise depend on a variety of factors, including the removal of the restrictions on the payment of dividends contained in the Credit Facilities, prevailing economic and competitive environment, results of operations, fluctuations in working capital, the price of oil and gas, the taxability of the Corporation, the Corporation’s ability to raise capital, the amount of capital expenditures, the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends, applicable law and other factors. See “*Dividend Policy*”.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "SGY". The following table sets forth the market price ranges and the trading volumes for the Common Shares for the periods indicated, as reported by the TSX, for the year ended December 31, 2022.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
January	6.79	4.54	33,206,200
February	7.76	6.20	18,919,600
March	9.48	7.70	25,670,200
April	10.83	8.57	19,603,600
May	11.84	9.20	21,438,000
June	13.68	8.62	22,178,900
July	10.27	7.20	17,883,300
August	10.98	8.32	12,979,300
September	9.88	7.15	13,104,400
October	10.51	8.09	12,328,100
November	10.64	8.30	26,614,200
December	10.19	8.09	14,001,000

The Debentures are listed and posted for trading on the TSX under the trading symbol "SGY.DB.A". The following table sets forth the market price ranges and the trading volumes for the Debentures for the periods indicated, as reported by the TSX, for the year ended December 31, 2022.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
January	100.99	98.50	445,000
February	102.00	100.00	441,000
March	103.00	100.50	820,000
April	102.40	100.04	97,000
May	101.50	100.30	333,000
June	102.50	101.20	1,102,000
July	102.00	100.05	6,039,000
August	102.00	100.05	174,000
September	101.50	100.00	238,000
October	101.00	100.00	257,000
November	102.50	99.76	319,000
December	101.51	100.00	266,000

DIRECTORS AND OFFICERS

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

Name and Residence	Position	Principal Occupation During Previous Five Years
Paul Colborne Alberta, Canada	President and Chief Executive Officer Director since April 13, 2010	President and Chief Executive Officer of the Corporation. He is also the President of Star Valley Oil and Gas Ltd., a private Calgary-based oil and gas company. In 1993, after nine years practicing securities, banking, and oil and gas law, Mr. Colborne directed his focus to the oil and gas industry and founded Startech Energy Ltd., a publicly traded company which grew to 15,000 boepd. In 2001, Startech was acquired by ARC Energy Trust for more than $500 million. From 2003 to 2005, Mr. Colborne was the President and Chief Executive Officer of StarPoint Energy Trust, a 36,000 boepd publicly traded energy trust. From 1996 to 2013, Mr. Colborne was on the Board of Directors of Crescent Point Energy Corp., a 110,000 boepd publicly traded oil and gas company. In 2014, Paul stepped down from the Board of Legacy Oil & Gas and completed his term as Chairman of New Star Energy Ltd. He served as Chairman of Rising Star Resources Ltd. until its sale in 2022. He was also previously on the Board of Directors of Westfire Energy Ltd., Twin Butte Energy Ltd., Red River Oil Inc., Cequence Energy Ltd., Seaview Energy Ltd., Breaker Energy Ltd., Mission Oil and Gas Inc., and TriStar Oil & Gas Ltd.
James Pasieka Alberta, Canada	Director since April 13, 2010 Chairman of the Board since January 7, 2015	Counsel to the national law firm McCarthy Tétrault LLP since January 1, 2020. Prior thereto, partner at McCarthy Tétrault LLP since September 1, 2013. Prior to that, partner of the national law firm Heenan Blaikie LLP since January 1, 2001. Mr. Pasieka has served as an officer and director of a number of public energy companies, and chairman of the board of several oil and gas companies.
Marion Burnyeat ICD.D(2)(4) Alberta, Canada	Director since July 16, 2018	Director, Calgary Academy and Headwater Learning Group since June 2018. Prior thereto, Director, SECURE Energy Services from April 2020 to July 2021. Consultant with Inter Pipeline Ltd. on mergers and acquisitions from April to June 2018. Vice President of Field Services at Westcoast Energy Inc. from January 2013 to March 2017. Prior thereto, Ms. Burnyeat served as Vice President of Midstream of Westcoast Energy Inc. from May 2008 to January 2013. She served as Vice President Strategic Development and Stakeholder Relations at Westcoast Energy Inc. from January 2007 to May 2008. Ms. Burnyeat has nearly 30 years experience in the energy sector primarily with Spectra Energy Corporation and its predecessor companies. She held increasingly responsible executive roles in leading Midstream business units, Strategic Development, Stakeholder Relations and Business Development. Ms. Burnyeat holds the ICD.D designation from the Institute of Corporate Directors, a Bachelor of Commerce degree from the University of Alberta and a Master of Business Administration degree from Edinburgh University, Scotland. She has held positions on not-for-profit boards and is an active volunteer for several charitable organizations including Freestyle Alberta.
Daryl Gilbert(2)(3) Alberta, Canada	Director since June 5, 2014	Chair of the Reserves Committee for the Corporation. Managing Director and Investment Committee member of Carbon Infrastructure Partners (formerly JOG Capital Inc. ("**JOG Capital**")) since May 2008. Mr. Gilbert has also been an independent businessman and investor, and serves as a director for a number of public and private entities, since 2005.

Name and Residence	Position	Principal Occupation During Previous Five Years
		Mr. Gilbert has been active in the Western Canadian oil and natural gas sector for over 40 years, working in reserves evaluation with Gilbert Laustsen Jung Associates Ltd. (now GLJ Petroleum Consultants Ltd. ("**GLJ**")), an engineering consulting firm, from 1979 to 2005. Mr. Gilbert served as President and Chief Executive Officer of GLJ from 1994 to 2005.
Michelle Gramatke(1) Alberta, Canada	Director since May 2019	Ms. Gramatke is a Chartered Accountant with over 25 years of financial experience. She has most recently acted as Chief Financial Officer of JOG Capital (a private equity investment firm based in Calgary) from 2004 until August 2020. Prior to her position with JOG Capital, Ms. Gramatke held several executive positions, including as Chief Financial Officer of PricewaterhouseCoopers Central Asia, Deputy Chief Financial Officer for an American NASDAQ-listed telecommunications company with operations in Russia and Manager with PricewaterhouseCoopers Moscow. Ms. Gramatke began her career with KPMG in Calgary focusing on Canadian upstream oil and gas, construction and mining companies.
Robert Leach(1)(2) Arizona, United States of America	Director since April 13, 2010	President of Sonoma Valley LLC Arizona Inc., a Phoenix based real estate investment company. Mr. Leach was formerly Chief Executive Officer of Custom Truck Sales Ltd., a private company operating Kenworth truck dealerships in Saskatchewan and Manitoba since 1986.
Allison Maher(1)(3) Alberta, Canada	Director since July 16, 2018	Chair of the Audit Committee. President, Director and Co-founder of Family Wealth Coach Planning Services since January 2009. Prior thereto, Ms. Maher worked at other financial-advisory and estate-planning companies such as Great-West Life (London Life) for a decade. Ms. Maher began her career at KPMG in the areas of Tax and Corporate Audit. Ms. Maher has her Certified Corporate Director, Chartered Professional Accountant, Certified Financial Planner, Trust and Estate Practitioner and Family Enterprise Advisor designations. Ms. Maher received her Bachelor of Commerce degree, with Distinction, from the University of Calgary. Ms. Maher is an active member of the Institute of Corporate Directors, Chair of TIGER21 Calgary and currently holds board positions on several not-for-profit boards.
P. Daniel O'Neil(3)(4) Alberta, Canada	Director since April 13, 2010	Chair of the Environment, Health and Safety Committee for the Corporation. Independent businessperson since his retirement on May 8, 2013. Prior thereto, Mr. O'Neil had acted as President and Chief Executive Officer of the Corporation from April 13, 2010 until his retirement and as President and Chief Executive Officer of Breaker Energy Ltd., a publicly traded oil and natural gas company, from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009. Mr. O'Neil was also a director of Cathedral Energy Services Ltd. Prior to their sales, Mr. O'Neil was acted as a Director of Hyperion Exploration Corporation and Cequence Energy Ltd.
Murray Smith(2)(4) Alberta, Canada	Director since June 25, 2010	Chair of the Compensation, Nominating and Corporate Governance Committee for the Corporation. President of Murray Smith and Associates. Mr. Smith also serves on the board of two private companies and Williams Companies Inc. (WMB.nyse), a Tulsa based midstream company. Prior thereto, Mr. Smith acted as an Official Representative of the Province of Alberta to the United States of America until 2007.

Name and Residence	Position	Principal Occupation During Previous Five Years
		Prior thereto, Mr. Smith was a member of the Legislative Assembly in the Province of Alberta serving in four different Cabinet portfolios – Energy, Gaming, Labour, and Economic Development from 1993 to 2005.
Murray Bye Alberta, Canada	Chief Operating Officer	Chief Operating Officer of the Corporation since August 2018. Prior thereto, Mr. Bye acted as Vice President, Production of the Corporation from May 2013. Prior thereto, Mr. Bye was Asset Team Lead – West at Surge since June 2010. Prior to his role at Surge, Mr. Bye held a number of positions at EnCana Corporation between the years 2000 to 2010 including: Group Lead of Development, Exploitation Engineer, and Production Engineer. Mr. Bye received a Petroleum Engineering degree from Montana Tech.
Jared Ducs Alberta, Canada	Chief Financial Officer	Chief Financial Officer of the Corporation since August 2019. Prior thereto, Mr. Ducs has held several progressively more senior roles at the Corporation including Director of Corporate Development, Assistant Controller and Manager of Financial Reporting and, most recently, held the position of Vice President, Finance of the Corporation since August 2018. Preceding his role at the Corporation, Mr. Ducs was a senior member of the Finance group at Breaker Energy Ltd. prior to its sale to NAL Oil & Gas Trust in 2009. Prior thereto, Mr. Ducs was a senior associate with Ernst & Young LLP. Mr. Ducs holds a Charted Accountant Designation and received his Bachelor of Management in Accounting and Finance from the University of Lethbridge.
Derek Christie Alberta, Canada	Senior Vice President – Geosciences	Senior Vice President, Geosciences of the Corporation since November 2019. Prior thereto, Mr. Christie acted as the Senior Vice President of Exploration & Corporate Development at Crescent Point Energy and was previously employed with Crescent Point Energy in various Senior Management positions in exploration, geosciences and corporate development since February 2007.
Margaret Elekes Alberta, Canada	Senior Vice-President, Land and Business Development	Senior Vice-President, Land and Business Development of the Corporation since August 2018. Prior thereto, Ms. Elekes held the position of Vice-President, Land and Business Development of the Corporation from August 2016. Prior thereto and since April 2010, Ms. Elekes acted as Vice-President, Land of the Corporation at Surge. Prior thereto, Ms. Elekes acted as Consulting Landman for Breaker Energy from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009. Prior thereto, Ms. Elekes acted as Landman and US Land Manager for Upton Resources from December 1995 until its acquisition by StarPoint Energy in February 2004.

Notes:
1. Member of the Audit Committee.
2. Member of the Compensation, Nominating and Corporate Governance Committee of the Board.
3. Member of the Reserves Committee of the Board.
4. Member of the Environment, Health and Safety Committee of the Board.

As at March 8, 2023, the directors and executive officers of the Corporation, as a group, beneficially own, control or direct, directly or indirectly, 2,518,339 Common Shares, representing approximately 2.6 percent of the outstanding Common Shares.

The terms of office of each of the directors of the Corporation will expire at the next annual general meeting of the shareholders of the Corporation.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as set forth below, to the knowledge of management of the Corporation:

a) no director or executive officer of the Corporation is, or within the 10 years before the date of this AIF, has been, a director, chief executive officer or chief financial officer of any other issuer that: (i) was the subject of a cease trade or similar order or an order that denied the other issuer access to any exemptions under Canadian securities legislation that lasted for a period of more than 30 consecutive days that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation that lasted for a period of more than 30 consecutive days 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 the person was acting in the capacity as director, chief executive officer or chief financial officer;

b) no director or executive officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person: (i) is, at the date of this AIF or has been within the 10 years before the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or shareholder; and

c) no director or executive officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has: (i) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or (ii) been subject to 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.

Mr. Gilbert was a director of LGX Oil and Gas Inc. ("**LGX**"), a public oil and gas company, from August 2013 until June 2016. On June 7, 2016 a consent receivership order was granted by the Alberta Court of King's Bench (the "**Court**") upon an application by LGX's senior lender. LGX's stock was cease traded shortly thereafter and a receiver manager was appointed. Mr. Gilbert was a director of Connacher Oil & Gas Limited ("**Connacher**") from October 2014 until February 2019. On May 17, 2016, Connacher applied for and was granted protection from its creditors by the Court pursuant to the *Companies' Creditors Arrangement Act* (Canada). On February 16, 2019, Connacher announced that it was proceeding to close on a credit bid transaction with its supporting lenders. Mr. Gilbert resigned from the Board shortly thereafter. Mr. Gilbert was a director of Trident Exploration Corp. ("**Trident**") from 2010 through year end 2018. On April 30, 2019, Trident announced it had ceased operations and had transferred all assets to the Alberta Energy Regulator. On May 3rd, 2019, PricewaterhouseCoopers LLP was appointed receiver.

Mr. Pasieka was also a director of LGX. Mr. Pasieka resigned as a director of LGX in July 2015. LGX was placed into receivership nearly twelve months later in June 2016 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Cease trade orders in respect of LGX were issued shortly after the appointment of the receiver.

Conflicts of Interest

As at the date hereof, the Corporation is not aware of any existing or potential material conflicts of interest between the Corporation and a director or officer of the Corporation.

AUDIT COMMITTEE

Composition of the Audit Committee, Charter and Review of Services

The Audit Committee of the Board of Directors operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this AIF as Schedule "C".

The members of the Audit Committee of the Board of Directors are Allison Maher (Chair), Robert Leach and Michelle Gramatke. The Audit Committee charter requires all members of the Audit Committee to be "financially literate" and "independent" within the meaning of applicable securities laws. All members of the Audit Committee meet these requirements. The relevant education and experience of each Audit Committee member is outlined below:

Name	Independent	Financially Literate	Relevant Education and Experience
Allison Maher	✓	✓	Ms. Maher is currently the President and Director of her own advisory firm, Family Wealth Coach Planning Services. She is highly involved in matters related to succession planning, as well as family governance, estate and risk management. Ms. Maher began her career with KPMG in the areas of Tax and Corporate Audit. Ms. Maher is presently a member of the Chartered Professional Accountants of Alberta, as well as an active member of the Institute of Corporate Directors, Chair of TIGER21 Calgary and currently holds board positions on several not-for-profit boards. Ms. Maher also holds Certified Corporate Director and Certified Financial Planner designations. Ms. Maher has been a member of the board of the Calgary Health Foundation since February 2020 and was a member of the board of the Heritage Park Foundation since June 2014 to June 2020. Ms. Maher has been a trustee for the Cidel Donor Advised Fund since June 2014. From May 2011 to May 2017, she served as chairperson and advisory board member for the Alberta Business Family Institute (University of Alberta). Ms. Maher holds a Bachelor of Commerce degree, with Distinction, from the University of Calgary.

Name	Independent	Financially Literate	Relevant Education and Experience
Robert Leach	✓	✓	Mr. Leach is currently the President of Sonoma Valley LLC Arizona Inc., a Phoenix based real estate investment company. Mr. Leach was formerly the Chairman of the board of Breaker Energy Ltd. and holds a Bachelor of Commerce degree, majoring in accounting, from the University of Saskatchewan. Mr. Leach has experience reviewing and assessing financial statements from his tenure on the audit committee of Breaker, as a member of the Board of Surge, and through his years of experience at Custom Truck Sales Ltd. and International Fitness Holdings.
Michelle Gramatke	✓	✓	Ms. Gramatke was Chief Financial Officer and Chief Compliance Officer of JOG Capital, a Calgary based private equity investment fund advisor which invests in Canadian oil & gas companies from 2004 to August 2020. Ms. Gramatke was responsible for JOG Capital's financial reporting, treasury, tax and regulatory compliance.Ms. Gramatke is presently a member of the Chartered Professional Accountants of Alberta and holds a Bachelor of Management degree from the University of Lethbridge.

Pre-Approval of Policies and Procedures

The Audit Committee charter requires that any non-audit services by the Corporation's auditors must be pre-approved by the Audit Committee. The Audit Committee has passed a resolution providing the Chairman of the Audit Committee with delegated authority to approve the provision of non-audit services by the Corporation's auditors from time to time, provided that: (i) such services are provided pursuant to a written engagement letter setting out the services to be provided and the applicable fees; (ii) the provision of such services is otherwise in compliance with the Audit Committee's charter; (iii) such services could not be reasonably seen to result in the auditors performing any management function, auditing their own work or serving in an advocacy role on behalf of the Corporation; (iv) the fees for such services do not exceed $50,000 per engagement; and (v) the Chairman reports to the Committee at the next regularly scheduled meeting any approval of non-audit services made pursuant to the authority delegated under the resolution. The Audit Committee also pre-approves all audit services and the fees to be paid.

External Auditor Service Fees

KPMG LLP are the auditors of the Corporation. KPMG LLP have been the auditors of the Corporation since May 5, 2010.

The following table sets out the aggregate fees billed by KPMG LLP to the Corporation in each of the last two fiscal years.

Year	Audit Fees(1)	Audit-Related Fees	Tax Fees(2)	All Other Fees
2022	$395,900	$nil	$281,888	$118,770
2021	$406,600	$nil	$123,553	$64,200

Notes:

1. Audit fees consist of fees for the audit of annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. The services provided in this category included quarterly review fees.
2. Fees for tax compliance, tax advice and tax planning.

INDUSTRY CONDITIONS

Companies carrying on business in the petroleum and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and, with respect to the pricing and taxation of crude oil 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 Canadian petroleum and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. While such regulations do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such legislation, regulations and agreements carefully.

Pricing and Marketing in Canada

Crude Oil

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

In 2020, worldwide oversupply of crude oil, a lack of available storage capacity and decreased demand due to COVID-19 have had a continuing significant impact on the pricing of crude oil. In an effort to stabilize global oil markets, the Organization of Petroleum Exporting Countries ("**OPEC**") and a number of other oil producing countries announced an agreement to cut crude oil production by approximately 10 million bbl/d in April 2020, which was amended and adjusted throughout 2020 and early 2021. The oil markets began to rebalance in 2021 with oil prices reaching their highest levels in six years. The rebound continued into 2022 with a surge in oil prices in early 2022 primarily in response to the to the impact of the Russian invasion of Ukraine and the Organization of the Petroleum Countries Plus ("**OPEC+**") decision to adhere to previously agreed upon production cuts, together with the improvement of global economic conditions and outlook due to reduced and eased COVID-19 restrictions. However, prices began to drop in the latter half of 2022. Amid fear of a global recession, increasing interest rates and continuing COVID-19 restrictions in China, lower demand and continuing sanctions and price caps placed on Russian oil, oil prices began to drop in the summer of 2022, with Saudi Arabia capping production and the Group of Seven nations agreeing to put a price cap on Russian oil. At a meeting in early December 2022, OPEC+ decided to maintain its oil output targets following its decision in October 2022 to cut output by 2 million barrels per day. In December 2022, the Group of Seven Nations and the European Union agreed on a ban on Seaborne exports of Russian-origin crude oil, placing a price cat at US$60 per barrel, effective December 5, 2022. The European Union also announced a price cap which can be triggered starting February 15, 2023 if prices for natural gas exceed 180 euros per megawatt hour for three days on the Dutch Title Transfer Facility gas hub's front-month contract. On February 4, 2023, the European Union introduced a price cap on certain Russian petroleum products, effective February 5, 2023, covering certain petroleum products that are traded at a discount or at a premium to crude oil.

With a continuing shift to alternative energy sources, there has been a decline in oil demand growth, which is expected to continue into 2023. While the trajectory of oil prices continue to be subject to uncertainty and volatility, factors such as the continued COVID-19 restrictions in China and conflict in Ukraine continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Risk Factors – Impact of the COVID-19 Pandemic and Associated Risks*" and "*Risk Factors – Commodity Prices, Markets and Marketing*".

Natural Gas

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

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane, propane and pentane plus sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGL 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 NGL, 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

In the summer of 2019, the National Energy Board (the "**NEB**') was replaced with the Canadian Energy Regulator (the "**CER**"). The CER's governing legislation is the *Canadian Energy Regulator Act* (the "**CERA**") and the *Impact Assessment Act* (the "**IAA**").The CER assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL from Canada.

Exports of crude oil, natural gas and NGL from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**") until such time as the Part VI Regulation is replaced. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas not exceeding 30,000 m^3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL). With respect to applications for long-term export licences, following a review of such applications by the CER, which may involve a public hearing, the CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes are not greater than Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences also currently require various other ministerial and federal Cabinet approvals.

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.

Transportation Constraints and Market Access

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGL is the deficit of transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation and export projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other 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.

Pipelines

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers and the price received.

Under the Canadian Constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines will require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments, public interest groups and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

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

Specific Pipeline Updates

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, Enbridge Inc.'s ("**Enbridge**") Line 3 Replacement Project (the "**Line 3 Replacement**") from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, experienced permitting difficulties in the United States and completion of the United States portion of the pipeline replacement was delayed following the announcement that the Minnesota Pollution Control Agency would require a public hearing concerning a key water permit. In June 2021, the Minnesota Court of Appeals declared that the Minnesota Utilities Commission correctly granted Enbridge a certificate of need and a pipeline routing permit for the final segment of the Line 3 Replacement. The Minnesota Supreme Court refused to hear an appeal on this matter.

After more than eight years, on September 29, 2021 Enbridge announced the completion of the 542 km Minnesota segment of the Line 3 Replacement. The Line 3 Replacement's in-service date was October 1, 2021 and is expected to transport 760,000 barrels per day at full capacity.

In October 2022, a Minnesota District Court upheld approvals given to the Line 3 Replacement, which were challenged on the basis that the U.S. Army Corps of Engineers should have taken into consideration how the broader project would impact climate change. The U.S. Army Corps of Engineers limited their environmental review of the project only to the impacts of construction in Minnesota rather than downstream concerns like greenhouse gas ("**GHG**") emissions from the ultimate burning of the crude oil carried in the pipeline.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the federal government's Indigenous consultations. The federal Court of Appeal quashed the approval and directed Cabinet to correct these deficiencies. Following a reconsideration by the NEB and enhanced consultation efforts led by the federal government, Cabinet re-approved the Trans Mountain Pipeline expansion. Subsequent challenges to the approval were rejected by the federal Court of Appeal in February 2020 and the Supreme Court of Canada ("**SCC**") in July 2020.

In addition, on April 25, 2018, the Government of British Columbia submitted a reference question to the British Columbia Court of Appeal, asking whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal unanimously answered the reference question in the negative. On January 16, 2020, the SCC unanimously dismissed the Attorney General of British Columbia's appeal.

Construction commenced on the Trans Mountain Pipeline expansion in late 2019 and mechanical completion of the project is expected to occur in the third quarter of 2023.

TC Energy Corporation's ("**TC Energy**") Keystone XL Pipeline was expected to begin construction in the first half of 2019 but pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. On March 31, 2020, TC Energy announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US $1.1 billion equity investment in the project and would guarantee a US $4.2 billion project level credit facility.

While construction on the Keystone XL Pipeline started in April 2020, the Keystone XL Pipeline remained subject to legal and regulatory barriers in the United States. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block certain permits and on April 15, 2020, a Montana judge ruled against the U.S. Army Corps of Engineers' use of a national permit for water crossings in the United States ("**Nationwide Permit 12**"). The United States Court of Appeals for the Ninth Circuit refused to stay the ruling. While the Supreme Court of the United States subsequently reinstated Nationwide Permit 12 in July 2020, it determined that the reinstatement would not apply to the Keystone XL Pipeline.

On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States, following which the Biden administration announced its decision to revoke the federal permit granted by the previous administration for the Keystone XL Pipeline, which has overturned a comprehensive regulatory process that lasted more than a decade. As a result of the revocation, and following a comprehensive assessment of its options and consulting with its partners and stakeholders, including the Government of Alberta, on June 9, 2021, TC Energy terminated the Keystone XL Pipeline project.

Following midterm elections in the fall of 2022, the Republicans have regained control of the House of Representatives. While the Republican's political agenda is expected to include acts regarding American energy independence, it is uncertain what this will mean for the advancement of pipeline projects between Canada and the United States.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGL or persistent crude oil products in excess of 12,500 metric tonnes 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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbl/d of crude oil out of the province to help alleviate the transportation constraints impacting Canadian oil prices.

In the spring of 2019, the Government of Alberta announced it would cancel the program and assign the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020, that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in early April 2020 and will remain in place until permanent rule changes are approved. As a result, trains subject to the order will be required to adhere to the reduced speed limits announced in February 2020 within metropolitan areas, with further mandatory speed reductions applying outside of metropolitan areas during winter months (November 15 to March 15). As of the date of this AIF, no permanent rules have been approved.

Natural Gas and LNG

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to 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 in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (the "**NGTL System**") to prioritize deliveries into storage (*temporary service protocol*). The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. An expansion to the NGTL System was recommended for approval by the CER which was sent to the federal Cabinet for approval. On April 30, 2021, the Governor in Council approved the issuance of the certificate of public convenience by the CER.

In July 2020, the Explorers and Producers Association of Canada applied to extend the temporary service protocol, which was opposed by NGTL and ultimately denied by the CER in February 2021.

In January 2022, the CER issued its decision denying NOVA Gas Transmission Ltd.'s application for a proposed firm transportation linked service from receipt points along the North Montney Mainline in Northeast British Columbia to the proposed Willow Valley Interconnect delivery point. In its decision the CER stated the tolling methodology proposed would result in unjust and unreasonable tolls.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of liquefied natural gas ("**LNG**") export plants have been proposed in Canada, regulatory and legal uncertainty, opposition from environmental and Indigenous groups and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). The CGL Pipeline is being built by TC Energy. Pre-construction activities 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 intense legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays to construction activities on the CGL Pipeline. The CGL Pipeline is currently 80% complete and is slated to have a mechanical in-service date by the end of 2023.

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project (the "**Woodfibre LNG Project**"), a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited, a subsidiary of Woodside Petroleum Ltd. However, both partners are looking to sell some or all of their interest in the project. Both parties elected to cease funding further feasibility work for the proposed Woodfibre LNG Project with both parties exiting the project. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. As of July 2022, Pacific Energy Corporation Limited and Enbridge entered into a partnership agreement, pursuant to which they have agreed to jointly invest in the construction and operation of the Woodfibre LNG Project. The BC Oil and Gas Commission ("**BC Commission**") approved a project permit for the Woodfibre LNG Project in July 2019. In April 2022, a Notice to Proceed was issued, instructing the contractor to begin the work required to move the project toward major construction commencement in 2023. The Woodfibre LNG Project is expected to be substantially completed in Q3 2027. In November 2022, certain amendments to the conditions listed in the Impact Assessment Agency of Canada's decision statement for the project were proposed, which were made available for public comment until December 2022.

GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026. Pieridae Energy Ltd.'s (**"Pieridae**") proposed Goldboro LNG project, located in Nova Scotia, would see LNG exported from Canada to European markets. Pieridae has a downstream agreement with Uniper, a German utility, for all of the LNG produced at Goldboro's train. The federal government has issued Goldboro LNG a 20-year export licence, but Pieridae decided in July 2021 not to proceed with the project.

Cedar LNG Export Development Ltd.'s Cedar LNG Project near Kitimat, British Columbia, is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office (the **"BC EAO**") conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**"). On June 8, 2021 the Haisla First Nation and Pembina Pipeline Corporation announced a partnership agreement whereby Pembina Pipeline Corporation will become the Haisla Nation's partner in the development of the Cedar LNG Project.

The BC EAO completed its assessment of the application for an Environmental Assessment Certificate in November 2022. The project has been referred to provincial decision makers and provided to the federal Minister of the Environment and Climate Change to inform the federal decision. The decision is expected within 45 days. As of the date of this AIF, no decision has been rendered. Ksi Lisims LNG project, owned by Nisga's Lisims Government, Rockies LNG Partners and Western LNG is currently in the environmental assessment stage, with the BC EAO conducting the environmental assessment on behalf of the IA Agency. Construction is anticipated to begin in 2024 with the site operational in late 2027 or 2028.

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system transporting crude oil. The changes that Enbridge wished to implement included the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein shippers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. On November 26, 2021, the CER issued its Reasons for Decision in Enbridge Pipelines Inc. RH-001-2020, denying the application to introduce firm service on the Canadian Mainline. If approved, the application would have made 90% of the Canadian Mainline's currently uncommitted capacity subject to firm contracts for priority access, with contract terms ranging from eight to 20 years. Contracts for firm service were to be awarded through an open season process put forward as part of the application.

The United States Mexico Canada Agreement and Other Trade Agreements

NAFTA/USMCA

The North American Free Trade Agreement ("**NAFTA**") that previously existed among the governments of Canada, the United States and Mexico has been replaced by a new trade agreement, widely referred to as the United States Mexico Canada Agreement ("**USMCA**") and sometimes referred to as the Canada United States Mexico Agreement ("**CUSMA**"). The USMCA came into force on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGL from Canada, the implementation of the USMCA could have an impact on Western Canada's petroleum and natural 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 other international markets.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world and, as a result, a number of free trade or similar agreements are in force between Canada and certain other countries. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union.

Although CETA has not received full ratification by national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union ("**Brexit**") on January 31, 2020, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"). On December 9, 2020, the Government of Canada introduced Bill C-18, an *Act to Implement the Trade Continuity Agreement*. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021 and CUKTCA came into force on April 1, 2021. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

Canada and 10 other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**") on March 8, 2018, which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among: Canada, Australia, Japan, Mexico, New Zealand, Singapore, Vietnam, and Peru. As other countries ratify the agreement, they are added to the annexes. The CPTPP facilitates temporary entry to Canada for certain categories of business persons who are citizens of other countries which are signatories to the CPTPP.

While it is uncertain what effect CETA, CPTPP, 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

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

In response to COVID-19, the governments of Alberta, British Columbia and Saskatchewan announced measures to extend or continue Crown leases and permits that may have otherwise expired in the months following the implementation of pandemic response measures. In March 2020, the British Columbia Ministry of Energy, Mines and Low Carbon Innovation announced that it was suspending posting requests and dispositions of petroleum and natural gas rights until further notice due to COVID-19. In December 2020, the monthly tenure process was resumed.

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

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence.

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 licences. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by the federal government on behalf of First Nations or national parks and by private freehold owners. Rights to explore for and produce privately-owned crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop crude 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 ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, crude oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the *1995 Regulations*). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"); however, the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019.

Surface Rights

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

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the freehold mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for volume-based incentive programs, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity.

In addition, incentive programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGL, or improve environmental performance.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the petroleum and natural gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the petroleum and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada.

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

The Corporation has the flexibility to negotiate and adapt its royalty arrangements with third parties to affect the profitability of the exploration, development and production of crude oil and natural gas related to its Lessor Interests or GORR Interests in the appropriate circumstances, including consideration of the existing royalty regime established by each province (as described below) and any amendments to that regime.

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights and crude oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis.

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. As of January 1, 2027, these older wells will become subject to the Modernized Framework. The *Royalty Guarantee Act* (Alberta), which came into effect on July 18, 2019, provides that no major changes will be made to the current crude oil and natural gas royalty structure for a period of at least 10 years.

Royalties on production from non-oil sands wells under 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.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues at a royalty rate between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices and operates on a sliding scale.

Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum rate of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low-cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance.

Crude oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* (Alberta) was amended in 2014 to shorten the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three years.

Subject to certain available incentives, royalty rates for conventional crude oil production subject to the Old Framework range from a base rate of 0% to a cap of 40%; royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 meters deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGL is a flat rate of 40% for pentanes and 30% for butanes and propane.

Oil sands production is also subject to Alberta's royalty regime. The Modernized Framework does not impact or change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for West Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55/bbl and increase for every dollar by which the market price of crude oil increases to a maximum of 9% when crude oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar by which the market price of crude oil increases above $55/bbl to a maximum of 40% when crude oil is priced at $120/bbl or higher.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells. In addition to royalties, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments at a rate of $3.50 per hectare.

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

Freehold Mineral Taxes are levied annually for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties. Freehold Mineral Taxes are in addition to any other negotiated royalty or other payment required to be paid to the owner of such freehold mineral rights.

British Columbia

In May 2022, the government of British Columbia introduced a new royalty framework that is set to come into effect September 1, 2024 with a two-year transition period which began on September 1, 2022.

The new royalty framework will be based on a revenue-minus cost royalty system with price-sensitive royalty rates designed to reflect the value of the resource and achieve a return of 50% of profits after production costs are accounted for. New wells will pay a flat royalty of 5% until the capital spent on drilling and completions is recovered, following which, the well will move to a price-sensitive royalty rate between 5% and 40%. The range of the rate will vary by commodity type. During the transition period, any new wells which are spud on or after September 1, 2022 are not eligible for the deep-well royalty program, the marginal well royalty program or the ultra-marginal royalty program. Wells that are spud on or after September 1, 2022 will pay a 5% royalty rate for the equivalent of the first 12 production months, following which the wells will pay royalties based on the current royalty framework until September 1, 2024 when all the wells transition to the new framework.

Wells drilled prior to September 1, 2022 shall continue to pay royalties based on the current royalty framework until the new framework takes effect on September 1, 2024. The royalties payable by producers in British Columbia will vary depending on the types of wells and the characteristics of the substances being produced.

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty rate can be as high as 40%, depending on factors such as the volume of crude oil produced by the applicable well or tract and the crude oil vintage. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGL in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGL and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGL and sulphur, the royalty rates are fixed at 20% and 16.667%, respectively. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of crude oil and natural gas from freehold lands in British Columbia also pay monthly freehold production taxes to the Government of British Columbia.

For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGL and sulphur are flat rates of 12.25% and 10.25%, respectively. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale from $1.25 to $4.94 per hectare, depending on the total number of hectares owned by the entity.

The Ministry of Energy, Mines and Low Carbon Innovation intends to create a mechanism that will begin in early 2023 to allow producers to repurpose unused deep well entitlements by transferring them to a Healing Land and Emission Reduction Pool. Once allocated to a producer’s pool, the deep well credits will no longer be available to reduce royalties on the well they were originally allocated to.

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the *Resource Surcharge*) and royalties are applicable to revenue generated by entities focused on crude oil and natural gas operations. Crown royalties payable on the production of crude oil and natural gas are paid on a well-by-well basis. Producers of crude oil and natural gas receive royalty invoices from the Government of Saskatchewan on a monthly basis. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Additionally, a mineral rights acreage tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned regardless of whether or not there is production from the lands.

In addition to such surcharges and taxes, the Crown royalty rate payable in respect of crude oil, depends on a number of variables including, the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and subject to applicable deductions.

The amount payable as a Crown royalty in respect of production of natural gas and NGL is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells. As of April 1, 2021, on associated gas produced from wells other than gas wells, including natural gas produced from oil wells, the Minister of Energy and Resources implemented a five-year Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax. The moratorium is in connection with the Government of Saskatchewan's Growth Plan and is aimed at meeting the Government of Saskatchewan's regulatory obligations to reduce methane-based GHG emissions by 40% to 45% between 2020 and 2025. The Associated Gas Royalty Moratorium is applicable to natural gas produced on or after April 1, 2021 and before April 1, 2026.

The Government of Saskatchewan also has a drilling incentive whereby qualifying incentive volumes of newly drilled oil wells are subject to a maximum royalty rate of 2.5% for Crown production and a maximum production tax rate of 0% for freehold production.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced.

Manitoba

In Manitoba, the Crown owns only approximately 20% of the crude oil and natural gas rights in the province, with the remainder being freehold lands. The royalty amount payable on crude oil produced from Crown lands depends on the classification of the crude oil produced. Royalty rates on crude oil are calculated on a sliding scale with a range of 0% to approximately 42.8% based on the monthly crude oil production from a spacing unit, or crude oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on crude oil produced from Crown lands is calculated based on the amount of crude oil production allocated to a spacing unit in accordance with the applicable regulations. As such, the royalty payable by producers will vary depending on the underlying characteristics of the producer's assets.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated for each production month.

The Government of Manitoba maintains a Drilling Incentive Program (the "**MB Incentive Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The MB Incentive Program provides the licencee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no royalties are payable until the holiday oil volume has been produced. The MB Incentive Program consists of benefits that are specific to certain vertical, exploration and deep wells, as well as wells undergoing major workovers, wells for solution gas and wells converted to injection wells. In November 2020, the MB Incentive Program was extended without alteration until December 31, 2022.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of crude oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on crude oil is calculated on a sliding scale between 0% and approximately 40% based on the monthly production volume and the classification of crude oil as old oil, new oil, third-tier oil, and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month.

Freehold and Other Types of Non-Crown Land Royalties and Taxes

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the freehold mineral owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), Freehold Mineral Taxes or production taxes are levied on the production of crude oil and natural gas from freehold lands in each of the Western Canadian provinces where the Crown does not hold the mineral rights. A description of the Freehold Mineral Taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

Where crude oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers, and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

Regulatory Authorities and Environmental Regulation

General

The Canadian petroleum and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain petroleum and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalents ("**CO_2e**")), may impose further requirements on operators and other companies in the petroleum and natural 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.

On August 28, 2019, the IAA replaced the *Canadian Environmental Assessment Act, 2012* ("**CEAA 2012**") at the same time that the CERA replaced the NEB Act and the CER replaced the NEB. As part of the regulatory transition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

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

The IAA is similar to the repealed CEAA 2012 in that it 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 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 and peoples.

It also requires an expanded public interest assessment, including Indigenous consultation, as applicable. The impact assessment must look at the direct result of the project's construction and operation. Designated projects specific to the petroleum and natural gas industry include pipelines that require more than 75 km of new right 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.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. The Government of Alberta submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA. On May 10, 2022, the Alberta Court of Appeal released its opinion stating that the IAA went beyond the federal Parliament's constitutional authority and reached into areas of exclusive provincial authority. The federal Government has appealed the Alberta Court of Appeal's opinion to the SCC. The SCC will hear the matter on March 21, 2023 to March 22, 2023.

On June 21, 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* received Royal Assent and immediately came into force. Bill C-15 is the Government of Canada's response to requests to implement the *United Nations Declaration of the Rights of Indigenous Peoples* as a framework for reconciliation in 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* (Alberta) 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 Protected Areas (previously known as the 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 in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, increased seismicity 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 crude oil and natural gas production.

In recent years, hydraulic fracturing has been linked to increased seismicity in the 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 crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity 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**"). Crude 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 crude 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 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.

British Columbia

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

The Government of British Columbia has introduced a regime to monitor and manage the risk of induced seismicity related to crude oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The *Drilling and Production Regulation* requires a producer to suspend its operations if they trigger a seismic event with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC Commission before resuming production. In June 2016, the BC Commission amended the permitting process to require all natural gas producers to conduct ground monitoring and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). Permit holders in the Kiskatinaw Area are subject to additional requirements before they can conduct hydraulic fracturing operations, including developing a seismic monitoring and mitigation plan that is approved by the BC Commission, and notifying the BC Commission and local residents about planned hydraulic fracturing requirements. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BC Commission on demand. If a seismic event occurs, permit holders are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude and triggers a sliding scale of obligations from permit holders.

The obligations range from reporting the seismic event and developing an approved protocol for subsequent events, to initiating such protocols, to suspending operations until permitted to resume by the BC Commission. Future seismic events outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

An updated *Environmental Assessment Act* came into force on December 16, 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasizes early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act*, the Government of British Columbia enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the BC EAO will consider the environmental, health, cultural, social and economic effects of a proposed project.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the "**SKOGCA**") is the act governing the regulation of resource development operations in the province, along with *The Oil and Gas Conservation Regulations, 2012* (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). The Government of Saskatchewan has implemented a number of operational requirements, including an increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex database.

The environmental scheme in Saskatchewan is governed by *The Environmental Management and Protection Act, 2010* and *The Forest Resources Management Act*. In Saskatchewan, the ministry has adopted a results-based regulatory model which largely leaves the determination of how environmental protection is to be achieved with the respective proponent.

Manitoba

In Manitoba, the Petroleum Branch of the Department of Growth, Enterprise and Trade develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of crude oil and natural gas resources. Crude oil and natural gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* (the "**MBOGA**"), *The Oil and Gas Production Tax Act* and related regulations and guidelines. The *Environment Act* establishes the environmental assessment and licensing process for developments in Manitoba for projects which may have the potential to cause significant environmental and / or human health effects. Projects which are defined as developments which must undergo the environmental assessment and licensing process are listed in the *Classes of Development Regulation*.

Liability Management Rating Programs

Alberta

The AER oversees liability management in the province. On June 30, 2020, the Government of Alberta announced a new Liability Management Framework ("**AB LMF"**) that will replace the Alberta Liability Management Program ("**AB LMR Program**") and its constituent programs. The goal of the AB LMF is to implement a holistic and full lifecycle approach to reclamation and remediation obligations.

Since the announcement, the Government of Alberta has gradually begun to phase-in the AB LMF through legislative and AER directive amendments.

The announcement and implementation of the AB LMF and the desire to rethink liability management in Alberta follows the SCC's decision in Orphan Well Association v Grant Thornton Ltd. (also known as the "**Redwater decision**"). As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licencees or to require a licencee to pay a security deposit before approving a transfer when such a licencee 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 Bill 12: *The Liabilities Management Statutes Amendment Act* (the "**LMSAA**") which came into force on proclamation. The LMSAA places the burden of a defunct licencees' abandonment and reclamation obligations first on the defunct licencee's working interest partners, and second, the AER may order the orphan fund (the "**Orphan Fund**") to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

Alberta's OGCA established an Orphan Fund which is run by the Orphan Well Association ("**OWA**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licencee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be bankrolled exclusively by licencees in the former Licensee Liability Rating Program (the "**AB LLR Program**") and Alberta Oilfield Waste Liability Program (the "**AB OWL Program**") who contributed to a levy administered by the AER. However, the Government of Alberta has loaned the Orphan Fund approximately $335 million. The Government also covered $113 million in levy payments that licencees 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. Collectively, these programs were designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licencees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. Under the new AB LMF, the OWA has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

The AB LMR Program previously governed most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consisted of three distinct programs: the AB LLR Program, the AB OWL Program and/or the Large Facility Liability Management Program.

Following the Redwater decision, Alberta has committed to actively reducing inventories of orphan and inactive well sites in the province. It is the goal that the AB LMF will assist in addressing the OWA's inventory, creating a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project. The AB LMF addresses five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) a licencee capability assessment system to provide proactive support through ongoing financial capability review; (iii) mandatory spend targets to support inventory reduction; (iv) a process to address legacy and post-closure sites or sites that were remediated, reclaimed or abandoned prior to the AB LMF; and (v) the OWA taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure.

On December 1, 2021, the Government of Alberta announced amendments to Directive 006: *Licensee Liability Rating (LLR) Program* and a new Directive 080: *Licensee Life-Cycle Management* and accompanying Manual 023: *Licensee Life-Cycle Management*. A new Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* was also introduced in April 2021 which introduced new criteria for the AER to consider whether an applicant, licencee or approval holder poses an "unreasonable risk".

Among other changes under the AB LMF, the AB LLR Program and security deposit collection for licence transfer have been replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the AB LMF provides proactive support to distressed operators and requires companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the AB LMF each licencee is required to meet mandatory annual spend targets for well closures and abandonments. During the summer of 2022, the AER announced it would increase spend targets for liabilities in 2023 from $422 million to $700 million and released forecasted targets through 2027, each of which are expected to increase annually by 9%.

The AER in 2015 also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applied to all inactive wells that were noncompliant with Directive 013 as of April 1, 2015. The objective was to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licencee was required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The compliance deadline for the final year of the IWCP was extended from April 1, 2020 to September 1, 2020 and was concluded in March of 2021.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Participants seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The ABC, together with the inventory reduction program implemented under the AB LMF, which implements mandatory closure spend targets over a five-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

The AB LMF continues to be implemented by the AER with gradual and phasing changes to legislative, regulatory and AER directives required to effectively implement the AB LMF and properly phase-out the AB LMR Program as the AB LMR Program is integrated in several directives and throughout governing legislation.

British Columbia

The BC Commission previously oversaw a Liability Management Rating Program (the "**BC LMR Program**"), which was designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. In the spring of 2019, the BC Commission introduced a Comprehensive Liability Management Plan ("**CLMP**"). The purpose of the CLMP is to ensure that 100% of the costs associated with the reclamation of oil and natural gas sites is paid by industry, rather than the Government of British Columbia or residents of British Columbia. Pursuant to the CLMP, the BC Commission is implementing a Permittee Capability Assessment ("**PCA**") program. Similar to the framework to be implemented in Alberta, the PCA program is intended to be a holistic evaluation of permittees throughout the development life cycle and is intended to replace the BC LMR Program. The PCA program is intended to mitigate risk and minimize pressure on the Orphan Site Reclamation Fund.

In the spring of 2019, a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The OGAA permits the BC Commission to impose more than one levy in a given calendar year.

Effective May 31, 2019, the *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") established the first set of legally imposed timelines for the restoration of crude oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BC Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan. The BC Commission is currently drafting proposed amendments to expand the Dormancy and Shutdown Regulation to include pipelines, facilities and related activities. The comment period on the draft policy changes ended on July 30, 2022. It is unknown when the amended regulation is expected to be implemented.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administers the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licencee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund takes on the obligation of carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires all new licencees to submit a $10,000 non-refundable Orphan Fund fee in order to be deemed eligible to transfer licences, and all licencees whose deemed liabilities exceed their deemed assets (i.e., an LLR below 1.0) are required to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licencees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities and this data is publicly available. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

Manitoba

To date, the Government of Manitoba has not implemented a liability management rating program similar to those found in the other Western Canadian provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the *Drilling and Production Regulations*. The MBOGA also establishes the Abandonment Fund Reserve Account (the "**Abandonment Fund**"). The Abandonment Fund is a source of funds that may be used to operate or abandon a well or facility when the licencee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility.

Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred, as well as annual levies for inactive wells and batteries.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's petroleum and natural gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally provided funds through the Site Rehabilitation Program, which is closed to new applicants. The Government of British Columbia is disbursing its $120 million share of the federally provided funds through three programs: (i) the Dormant Sites Reclamation Program, which requires all work to be complete by December 31, 2022; (ii) the Orphan Sites Supplemental Reclamation Program; and (iii) the Legacy Sites Reclamation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund. And in early March 2020, the Government of Alberta announced an extension by up to $100 million of an existing $235 million loan to the Orphan Fund. In Saskatchewan, $400 million in federal funding was used for the Accelerated Site Closure Program ("**ASCP**"). The first phase of the ASCP made $100 million available to eligible service companies to conduct abandonment and reclamation work. The ASCP is in the final year of operation, with the program ending in the spring of 2023. In July 2022, the ASCP opened application processes to release all remaining ASCP funding to eligible licensees.

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 petroleum and natural gas industry in Canada. These impacts are uncertain and it is not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow. An example of a change in policy that may impact the petroleum and natural gas industry is the International Maritime Organization's implementation of regulations that limit the sulphur content of marine fuel oil, reducing the permissible amount of sulphur from 3.5% to 0.5%, effective January 1, 2020.

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. On January 20, 2021, President Biden of the United States signed an executive order to rejoin the Paris Agreement. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference, scheduled to take place in November 2021 in Glasgow. The result of The 2021 United Nations Climate Change Conference, more commonly referred to as COP26, was the Glasgow Climate Pact, negotiated through consensus of the representatives of the 197 attending parties. Owing to late interventions from India and China, that weakened a move to end coal power and fossil fuel subsidies, the conference ended with the adoption of a less stringent resolution than some anticipated. The Glasgow Climate Pact reaffirms the long-term global goals (including those in the Paris Agreement) to hold the increase in the global average temperature to below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, however, they have also indicated that they expect to implement policies to exceed this target. In connection with this target, 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. In March 2022, the Government of Canada also introduced Canada's 2030 Emissions Reduction Plan (the "**2030 Reduction Plan**"), which provides the building blocks for the Canadian economy to achieve 40% to 45% emissions reductions below 2005 levels by 2030. The 2030 Reduction Plan includes $9.1 billion in new investments as well as carbon pricing and clean fuels measures to assist in growing economic opportunities for a clean future. Progress of the 2030 Reduction Plan will be reviewed and produced in reports in 2023, 2025 and 2027, with additional targets to be developed for 2035 and 2050.

On December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the "**HEHE Plan**") which builds on the Pan-Canadian Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes a $3-billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional $964 million over four years towards renewable energy and grid modernization projects and $300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional $287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, $150 million over three years towards charging and refueling stations across Canada, and $1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels.

Also of relevance to the petroleum and natural gas industry, in June 2022, the federal government introduced the *Single-use Plastics Prohibitions Regulations* ("**SUPPR**"). The SUPPR prohibits, subject to certain exemptions, the manufacture, import and sale of single-use plastic checkout bags, cutlery, foodservice ware made from or containing problematic plastics, ring carriers, stir sticks and straws. The prohibitions on manufacture and import for sale in Canada and sale and manufacture, import and sale for export come into force on a rolling basis between December 2022 and December 2025.

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050. Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. The *Canadian Net-Zero Emissions Accountability Act* became law in June 2021 and legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation also sets rolling five-year emissions-reduction targets (starting in 2030) and requires emissions reduction plans to reach each target on a reporting basis and enshrines greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

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 for large industry ("**OBPS**") and a regulatory fuel charge (the "**Fuel Charge**") imposing an initial price of $20/tonne of CO_2e. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. In accordance with the HEHE Plan, the price on carbon is set to increase annually at a rate of $15/tonne of CO_2e per year commencing in 2023 through to 2030. In August 2021, the federal government established strengthened minimum national standards (the "**federal benchmark**") for 2023 to 2030, which includes the requirement that all jurisdictions establish systems that align with the federal carbon pricing trajectory and benchmark requirements to 2030. Once in place, the systems will remain until 2027.

Alberta, Saskatchewan, Ontario and Manitoba each challenged the constitutionality of the GGPPA. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the SCC and the hearing took place in September 2020. On March 25, 2021, the SCC released its decision in *Reference re Greenhouse Gas Pollution Pricing Act*, upholding the constitutionality of a federal law establishing minimum national standards for carbon pricing in Canada.

Manitoba also made an appeal to the Federal Court stating the federal government did not act properly in imposing a minimum price on carbon because Manitoba was planning to use its own lower price. In October of 2021, the Federal Court rejected Manitoba's argument stating the federal government's actions were consistent with the purpose of the GGPPA as was upheld by the SCC.

Following the SCC's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards or federal benchmarks. Currently the Fuel Charge applies in each of Ontario, Manitoba, Yukon, Alberta, Saskatchewan and Nunavut while the OBPS applies in Manitoba, Prince Edward Island, Yukon, Nunavut and partially in Saskatchewan. The provincial plans for each of Nova Scotia, Prince Edward Island and Newfoundland and Labrador were deemed by the federal government to have fallen short of the federal benchmark, making the federal OBPS applicable in each of those provinces as of July 1, 2023. For so long as the provincial systems in Alberta (under the *Technology Innovation and Emissions Reduction* (“**TIER**”) regulation) and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

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 petroleum and natural gas industry, 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, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

As part of its efforts to provide relief to Canada's petroleum and natural gas industry in light of the COVID-19 pandemic, on October 29, 2020, the federal government launched the $750-million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies.

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

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

The federal government has also announced that it will proceed with the development and implementation of a Clean Fuel Standard (“**CFS**”) that will require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels.

On December 18, 2020, the federal government published proposed CFS regulations, with the *Clean Fuel Regulations* ("**CFS Regulations**") coming into force on June 21, 2022. The CFS Regulations take a performance-based approach to reducing greenhouse gas emissions. The CFS Regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to reduce the carbon intensity of their liquid fossil fuels. Beginning in 2023, the carbon intensity reduction requirement will start at 3.5 g CO_2e/MJ, increasing by 1.5 gCO_2e/MJ each year and reaching 14 gC02e/MJ in 2030. The standard will apply to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The proposed regulations offer compliance credits, tracked via the Credit and Tracking System, and created a credit market to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (Alberta) (the "**CLA**") came into force on January 1, 2017 and established a fuel charge that was compliant with federal requirements. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed.

In June 2019, the Government of Alberta repealed the CLA and the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $50/tonne of CO_2e and will increase to $65/tonne on April 1, 2023. In December 2019, the federal government approved Alberta's TIER regulation, which applies to large emitters and those who have opted-in. The TIER regulation came into effect on January 1, 2020 and replaced the previous *Carbon Competitiveness Incentives Regulation*.

The provisions of the TIER regulation required that an interim review of the regulation be completed by December 31, 2022 giving stakeholders an opportunity to provide input on improvements to the TIER system and to enable the regime to meet the updated federal benchmark criteria for the assessment of the carbon pricing systems for 2023 to 2030. Following the comment period, the *Technology Innovation and Emissions Amendment Regulation* was adopted with certain amendments to the TIER Regulation which came into effect January 1, 2023. These amendments include meeting the federal standards for Alberta's carbon pricing system, the creation of sequestration credits for carbon capture, utilization and storage ("**CCUS**") projects and amendments to the number of credits that can be used to meet emission targets. The TIER regulation is set to undergo another review by December 31, 2026.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high performance benchmarks. Certain facilities, such as those in the electricity sector, 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 to ensure that the cost of ongoing compliance takes this into account. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that they do not meet the 100,000 tonne threshold. The amendments reduced the threshold for those to opt-in from 10,000 tonnes of CO_2e to 2,000 tonnes of CO_2e per year. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

As discussed above, the TIER regulation will continue to apply in Alberta for as long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020 and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting*. 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. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal. In May 2020, the Government of Canada and the Government of Alberta announced a preliminary equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply once the agreement is effective.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement CCUS technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale CCUS projects. Both projects will help reduce the CO2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment* Act, 2010. It deemed the pore space underlying all land in Alberta to be and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies will begin exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest $40 million in 11 CCUS hub projects through Emissions Reduction Alberta.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization. The Alberta Utilities Commission also released its Hydrogen Inquiry Report in September 2022 which reviewed the viability and impacts of hydrogen blending into natural gas distribution systems in Alberta.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050.

British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge was initially set at $40/tonne of CO_2e.

While the scheduled increase to \$45/tonne of CO_2e was delayed until October 1, 2020 in response to COVID-19, the Government of British Columbia announced on September 2, 2020 that the increase would not take place until April 1, 2021. On April 1, 2021, B.C.'s carbon tax rate rose from \$40/tonne to \$45/tonne of CO_2e and was increased again on April 1, 2022 to \$50/tonne of CO_2e. As noted above, the pollution pricing system in British Columbia currently meets the federal stringency requirements and in order to maintain its application, the fuel charge will increase to \$65/tonne of CO_2e in 2023 to maintain compliance with the federal benchmark.

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

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "CleanBC", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of crude oil and natural gas production; (v) reducing 45% of methane emissions associated with natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles. On July 6, 2021, the Government of British Columbia released the B.C. Hydrogen Strategy, which lays out a framework for the province to utilize hydrogen in support of its CleanBC plan. The Strategy sets out 63 actions to be undertaken over three periods of time: (i) short term (2020-2025), (ii) medium term (2025-2030), and (iii) long term (2030-beyond).

On January 16, 2019, the BC Commission announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia. The equivalency agreement will be in place for a period of five years.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. The Government of Saskatchewan subsequently released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* (the "**Saskatchewan Strategy**") outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

The MRGGA, which is partially compliant with the federal emissions trading system and was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full on December 18, 2018, establishing the framework of an output-based emissions management framework. In November 2022, the province of Saskatchewan received confirmation that a provincial plan has been approved to replace the federally imposed carbon tax on industrial emitters effective as of January 1, 2023. The Saskatchewan OBPS meets the federal stringency requirements and regulated emitters will receive credit for every tonne of CO_2e under their permitted amount.

The OBPS program in Saskatchewan will also include credits for CCUS. The OBPS program in Saskatchewan is implemented under the Saskatchewan Strategy. As noted above, the federal fuel charge applies in Saskatchewan.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations, the Management and Reduction of Greenhouse Gases (Reporting and General) Regulations, and The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, The Oil and Gas Emissions Management Regulations (the *Saskatchewan O&G Emissions Regulations*) came into effect. The Saskatchewan O&G Emissions Regulations apply to licencees of oil facilities that may generate more than 50,000 tonnes of CO_2e per year, obliging each licencee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40% to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO_2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO_2e by 2030.

On April 10, 2019, Saskatchewan produced its first annual report on climate resilience. The report measures the Province's progress on goals set out under *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy*. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

In October 2019, *The Oil and Gas Conservation Amendment Act* was proclaimed into force. This Act, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented *Directive PNG017: Measurement Requirements for Oil and Gas Operations*, which came into force in December 2019 and was amended in April 2020, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on or by December 31, 2024.

Manitoba

In 2018, the Government of Manitoba unveiled the *Climate and Green Plan Implementation Act* (the "**Implementation Act**"). The Implementation Act included a new *Climate and Green Plan Act*, a new *Industrial Greenhouse-Gas Emissions Control and Reporting Act* and various related amendments to existing legislation. Initially, the *Climate and Green Plan Act* introduced a charge of $25/tonne of CO_2e on GHG emissions, but this was subsequently withdrawn from the Act and the federal GGPPA applied in Manitoba. However, in March 2020, the Government of Manitoba introduced the *Climate and Green Plan Implementation Act, 2020*, which, among other things, reintroduces the $25 charge.

Following Manitoba's challenge in the Federal Court, it was determined that the federal government's fuel charge will backstop Manitoba's system because Manitoba's pricing regime is not stringent enough. The $25/tonne imposed by the *Climate and Green Plan Implementation Act, 2020* does not match increases in the federal benchmark and therefore is not a comparable system.

Manitoba intends to develop a policy approach to the new federal legislative and regulatory frameworks with its December 31, 2022 timeline. As of the date of this AIF, no policy approach has been announced.

The original *Climate and Green Plan Implementation Act* ("**CGPIA**") also required the Government of Manitoba to establish five-year emissions reduction targets. In June 2019, the Government of Manitoba announced a GHG emissions reduction target of one megatonne for the 2018-2022 period. Pursuant to the CGPIA, the minister must establish GHG emission reduction goals for each five-year period following 2022. The emission reduction goal for the 2023-2027 period was to be set prior to December 31, 2022. As of the date of this AIF, the emission reduction target for the subsequent period has not been set.

Accountability and Transparency

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

INDIGENOUS RIGHTS

Constitutionally mandated government-led consultation with and, if applicable, accommodation 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 natural 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 natural gas industry in Western Canada. On November 28, 2019, the *Declaration on the Rights of Indigenous Peoples Act* (the "**DRIPA**") became law in British Columbia. The Government of British Columbia recently released its interim approach in furtherance of its implementation of DRIPA which outlines a process for how new policy and legislation in the province are to be aligned with the UNDRIP. The action plan is the first of its kind to be enacted by any province and it is uncertain as to what potential consequences the implementation of the plan and its effects on future legislative drafting.

Similar to British Columbia's DRIPA, the *United Nations Declaration of the Rights of Indigenous Peoples Act* ("**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.

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 UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and natural gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The federal government 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, subject to the forthcoming opinion from the SCC, 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 October 7, 2021, the Government of British Columbia and the BRFN reached an initial agreement in response to the Blueberry Decision in which the parties agreed to negotiate a land management process for BRFN territory, and certain previously authorized forestry and oil and gas projects were put on hold pending further negotiation. On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nation Implementation Agreement ("**Implementation Agreement**"). On January 20, 2023, the Government of British Columbia also finalized a co-developed set of initiatives ("**Consensus Document"**) with four other Treaty 8 First Nations, including the Fort Nelson, Saulteau, Halfway River and Doig River First Nations ("**Treaty 8 Nations**"). Both the Implementation Agreement and the Consensus Document respond to the Blueberry Decision. The precedent established by the Implementation Agreement and the Consensus Document may extend beyond Treaty 8 territory and may have implications for resource development in British Columbia, Alberta and Canada at large.

The key elements of the Implementation Agreement are:

- *Wildlife Management*: The Government of British Columbia and BRFN are committing to bring together Indigenous knowledge and western science. Both parties will support a community stewardship, monitoring and guardian program. Further, important species will be closely monitored.

- *Land-Use Plans*: The Government of British Columbia and BRFN will engage in collaborative land-use planning, to determine whether certain activities can occur in Treaty 8 territory. Collaborative land-use planning includes a commitment to advance watershed-level land use plans within the next three years (Watershed Management Basin Plans).

- *Petroleum and Natural Gas*: The Government of British Columbia and BRFN will use a more collaborative approach to oil and natural gas development planning and projects. The Government of British Columbia, various companies and other First Nations will sit together and address: the establishment of areas for permanent protection; minimizing disturbance from petroleum and natural gas development; reducing new disturbance from petroleum and natural gas by approximately 50 percent from pre-Blueberry Decision years; introducing operational and strategic planning expectations for the sector; and limiting overall new disturbances from petroleum and natural gas activities in BRFN's claim area.

- *Forestry*: The Government of British Columbia and BRFN will protect old growth forest and reduce timber harvesting in defined high value areas. Key elements of the Implementation Agreement applicable to forestry include: a cessation to aerial herbicide use; a commitment to implementing ecosystem-based management, through Watershed Management Basin Plans; and two-year harvest schedule outside the BRFN's important forestry areas.

- *Honoring Treaty 8*: The Government of British Columbia and BRFN have agreed to work together on measures to honor Treaty 8, including improving awareness and education on Treaty 8. The Government of British Columbia and BRFN will honor Treaty 8 by sustaining communications, sharing training and awareness building, and providing support for communications with other Treaty 8 First Nations and local elected elders.

The Implementation Agreement also includes a $200 million restoration fund, which is meant to restore the land from industrial disturbance by June 2025. Further, BRFN will receive $87.5 million as a financial package, with an opportunity for increased benefits based on petroleum and natural gas revenue-sharing and provincial royalty revenues in the next two years.

According to the Government of British Columbia, the Consensus Document will address the cumulative impacts of industrial development on the meaningful exercise of Treaty 8 rights in the territory, restore land and produce stability and predictability for industry in the region and to promote responsible resource development and sustainable economic growth in Treaty 8 territory. Further, it aims to manage the impacts of industrial development through ecosystem-based stewardship and governance. The Consensus Document sets out various initiatives to outline how the Government of British Columbia and Treaty 8 Nations manage the land to achieve sustainability for future generations, meet the Crown's obligations to uphold constitutionally protected rights and support responsible resource development and economic activity in northeastern British Columbia. Specifically, the initiatives outlined in the Consensus Document include: (i) a new approach to wildlife co-management; (ii) new land-use plans and protection measures; (iii) a "cumulative effects" management system; (iv) pilot protects to advance shared decision-making for environmental planning and stewardship; (v) a multi-year, shared restoration fund; (vi) a new revenue-sharing approach to support the priorities of Treaty 8 First Nation communities; and (vii) actions to promote education about Treaty 8 through collaborative promotion, anti-racism training and awareness building.

The Government of British Columbia is still in ongoing discussions with other Treaty 8 First Nations, including McLeod Lake Indian Band, Prophet River First Nation and West Moberly First Nations.

The Implementation Agreement and Consensus Document remain confidential at the date of this AIF. Although the details have not been released, it is highly likely those documents will create additional consultation and regulatory obligations for operators seeking to develop natural resources in the affected region.

In July 2022, the Duncan’s First Nation in Northern Alberta filed a lawsuit claiming cumulative effects from industry, agriculture and settlement which violate their treaty rights. The claim advances many of the same grounds as those that were the subject of the Blueberry Decision.

The long-term impacts and risks of the Blueberry Decision, and any subsequent decisions, on the Canadian oil and natural gas industry remain uncertain.

RISK FACTORS

The Corporation is subject to both risks that directly affect its business and operations, as well as indirect risks that impact third parties or industry generally. 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, the business of third parties with whom the Corporation conducts business and the crude oil and natural gas business generally.

The acquisition, exploration and development of crude oil, condensate, other NGL and natural gas properties and the production, transportation and marketing of crude oil, condensate, other NGL and natural gas involves many risks, which may influence the ultimate success of the Corporation. If any of the risks set out below materialize, the Corporation's business, financial condition, results of operations, prospects, cash flow and reputation may be adversely affected, which may, in turn, reduce or restrict the Corporation's ability to pay dividends and may materially affect market prices of the Corporation's securities.

While the Corporation realizes these risks cannot be eliminated, it is committed to monitoring and mitigating these risks.

Impact of the COVID-19 Pandemic and Associated Risks

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide could have an adverse impact on our business, including changes to the way we and our counterparties operate, and on our financial results and condition. The spread of the COVID-19 pandemic continues to pose risks to the global economy and the petroleum and natural gas industry more broadly. At the onset of the COVID-19 pandemic in March 2020, governments and regulatory bodies in affected areas imposed a number of measures designed to contain the COVID-19 pandemic, including widespread business closures, social distancing protocols, travel restrictions, quarantines, curfews and restrictions on gatherings and events. While substantially all containment measures in Canada have been lifted, additional safety precautions and operating protocols aimed at containing the spread of COVID-19 may be instituted in line with guidance of public health authorities. Additional waves of the COVID-19 pandemic, together with the emergence of new COVID-19 variant strains may lead to the imposition of containment measures to varying degrees in many regions within Canada and globally. These containment measures have the potential to impact global economic activity and such measures may also contribute to the decreased demand for hydrocarbons, increased market volatility and continued changes to the macroeconomic environment. The prolonged effects of any disruption may have adverse impacts on our business strategies and initiatives, resulting in ongoing effects to our financial results, including the increase of counterparty, market and operational risks. Low prices for crude oil, NGL and natural gas would reduce the Corporation's cash flow from operating activities and impact the Corporation's level of capital investment and may result in the reduction of production at certain producing properties.

While the duration and full impact of the COVID-19 pandemic is not yet known, the effects of COVID-19 may also include disruptions to production operations, access to materials and services, increased employee absenteeism from illness and temporary closures of the Corporation's facilities. Uncertainty remains as to the full impacts of the COVID-19 pandemic on the global economy, commodity and financial markets, crude oil and natural gas capital investment levels in the Western Canadian Sedimentary Basin and the energy business more broadly. The ultimate impacts will depend on future developments that are highly uncertain and cannot be predicted, including the scope, severity, duration and additional subsequent waves of the COVID-19 pandemic, including the introduction of new variants, as well as the effectiveness of actions and measures taken by the various levels of government. If the COVID-19 pandemic is further prolonged, including the possibility of additional subsequent waves, and introduction of new variants, or further diseases emerge that give rise to similar effects, the adverse impact on the economy could deepen and result in further volatility and declines in commodity and financial markets. Moreover, it remains uncertain how the macroeconomic environment will be impacted following the COVID-19 pandemic. Unexpected developments in commodity and financial markets, regulatory environments, industrial activity or consumer behavior and confidence may also have adverse impacts on the Corporation's business and financial condition, potentially for a substantial period of time.

In virtually all aspects of our business and strategy, our view of risks is not static as our business activities expose us to a variety of risks. We actively manage our risks to help protect and enable our business and future prospects. Additionally, we continue to evaluate the impacts that the COVID-19 pandemic has had and continues to have on our business, including the impact on our top and emerging risks, operational and reputational risks as well as credit, market and liquidity and funding risks and environmental, social and governance risks. For further details on our risks, refer to the detailed risk factors below and throughout this AIF.

Credit Facilities Risks

The amounts authorized under the First Lien Credit Facilities is dependent on the borrowing base determined by the lenders thereunder. The Corporation is required to comply with covenants under the Credit Facilities which may 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 Credit Facilities, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facilities, the lenders under the Credit Facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation’s indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the 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 impact of the Supreme Court of Canada’s decision in the Redwater Decision case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has the effect of adjusting lending practices to account for end-of-life obligations that were thought to be subordinate to secured debt and will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See “*Industry Conditions – Liability Management Rating Programs*”.

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

Commodity Prices, Markets and Marketing

The Corporation's revenue, operating results and financial condition depend substantially on the prevailing prices for crude oil and natural gas and the Corporation's ability to successfully market its oil and natural gas production from its properties. Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of crude oil and natural gas acquired, produced or discovered by the Corporation.

The Corporation's ability to market crude oil and natural gas may depend upon the ability to acquire capacity in pipelines that deliver oil, NGL and natural gas to commercial markets or contract for the delivery of crude oil and NGL by rail (see “*Industry Conditions – Pricing and Marketing in Canada – Petroleum and Natural Gas Industry*” and “*Risk Factors – Weakness and Volatility in the Petroleum and Natural Gas Industry*”). Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of crude oil and natural gas acquired, produced, or discovered by the Corporation:

- 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 crude oil and natural gas.

Crude oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East, the war in Ukraine, concerns regarding COVID-19 and its impact on the supply of, and demand for, crude oil, NGL and natural gas, global crude oil, NGL and natural gas inventory levels, weather conditions affecting supply and demand, overall domestic and global economic conditions, currency fluctuations, social attitudes or policies affecting energy consumption and energy supply, domestic and foreign governmental regulations, including environmental regulations, climate change regulations and taxation, the effects of energy conservatism efforts and GHG reduction measures, the price, availability and acceptance of alternative energies, including renewable energy, and ongoing credit and liquidity concerns. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. A material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of the Corporation's anticipated production revenue.

The economics of producing from some wells may change because of lower prices, which could result in reduced production of crude oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation may also elect not to produce from certain wells at lower prices, which, in turn, would reduce the Corporation's production revenues. Any substantial and extended decline in or continued low crude oil and natural gas prices may impact the Corporation's carrying value of its reserves, royalty revenues, profitability and cash flow which may have a material adverse effect on the Corporation's business and financial condition. See "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*" and "*Risk Factors – Weakness and Volatility in the Petroleum and Natural Gas Industry*".

Volatile crude 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 crude oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities.

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic for development. The Corporation's reserves at December 31, 2022 are estimated using forecast prices and costs. If crude oil and natural gas prices decrease, the Corporation's reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel the Corporation to re-evaluate its development plans and reduce or eliminate various projects with marginal economics.

In addition, lower commodity prices may restrict the Corporation's cash flow resulting in less funds being available to fund the Corporation's capital expenditure programs. The Corporation's capital expenditure plans are impacted by the Corporation's cash flow. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year-over-year basis.

Additionally, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write-down of the carrying value of its crude oil and natural gas assets on its balance sheet and the recognition of an impairment charge on its income statement.

Exploration, Development and Production Risks

Crude 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 crude oil and natural gas reserves, as well as to acquire additional crude oil and natural gas assets to contribute to additional crude oil, natural gas and NGL reserves. A future increase in the Corporation's reserves will also depend on the ability of the Corporation to encourage further exploration on and development of its existing properties and its ability to select and acquire suitable producing properties or prospects. Without the continual addition of new reserves, the Corporation's existing reserves and production therefrom will decline over time as the Corporation produces from such reserves. There is no assurance that the Corporation will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of crude oil and natural gas.

Future crude oil and natural gas exploration may involve unprofitable efforts from dry wells or 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, which may result in decreased activities and therefore less revenue to the Corporation.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and the shutting-in 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 production, which may reduce the Corporation's revenue.

Crude 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 crude oil and natural gas wells, production facilities, other property, the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour natural 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.

Crude 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 negative or 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 and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs. See "*Risk Factors – Insurance*".

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership ("**TPP**") and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The U.S. has not indicated any intention to rejoin the TPP but could try to negotiate stronger labour and environmental standards. On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States. The political unrest associated with the transition to the new Biden administration was unprecedented in the United States, and the short and long-term impacts on business and capital markets are unknown. Additionally, on January 20, 2021, the Biden administration announced its decision to revoke the federal permit granted by the former administration for the Keystone XL Pipeline, which has overturned a comprehensive regulatory process that lasted more than a decade. In addition, NAFTA has been replaced with the USMCA. This has affected the competitiveness of other jurisdictions, including Canada. On January 25, 2021, the Biden administration signed an executive order with respect to stringent new Made-In-America rules for the U.S. government and has indicated that the exceptions to such rules will be very limited. It is unclear what the impact of the new executive order will be and how it may impact the USMCA and the Canada-U.S. supply chain. Further, it is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the petroleum and natural gas industry. Any actions taken by the current United States administration may have a negative impact on the Canadian economy and on the businesses, financial condition, results of operations, prospects and the valuation of Canadian crude oil and natural gas companies, which could also negatively impact the Corporation, which negative impact could prove to be material over time.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined, especially in a post-pandemic era. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, costs for goods and services required for the Corporation's business could increase and access to skilled labour could decrease, negatively impactinc the Corporation's business, financial condition, results of operations, prospects and the market value of its Common Shares, which negative impact could prove to be material over time.

Beginning in November 2021, Russia began to amass troops along the Ukrainian border, heightening military tension in Eastern Europe. In February 2022, Russia sent troops into pro-Russian separatist regions in Ukraine. Ongoing military tensions between Russia and Ukraine have the potential to threaten supply of oil and gas from the region and impact demand from other European countries as well as the possibility that other nations will impose certain tariffs and restrictions on oil from Russia. The long-term impacts of the tension between Russia and the Ukraine remains unclear, including the responses from other nations globally.

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 petroleum and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. In January 2020, the SCC unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain between provincial and federal governments. Continued uncertainty and delays, including a temporary shutdown due to flooding in British Columbia have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdictions where the Corporation’s operations are located.

Following former Alberta Premier Jason Kenney’s resignation on May 18, 2022, Danielle Smith was elected as Premier on October 11, 2022. Shortly after her appointment, Premier Smith introduced Bill 1: The Alberta Sovereignty Within a United Canada Act (the “**Sovereignty Act**”). The Sovereignty Act was passed on December 8, 2022 and received Royal Assent on December 15, 2022. The Sovereignty Act, amongst other things, enables the Alberta Government to choose which federal legislation, policies or programs it will enforce in Alberta, providing an overriding right to not enforce those which the Alberta Government deems to be “harmful” to Alberta’s interests or infringe on the Federal Constitution and its division of powers. The Sovereignty Act has been opposed by many, including the National Democratic Party and various Indigenous groups who have expressed concern as to how the Sovereignty Act will affect Indigenous rights and consultation obligations in Alberta. It is unclear what the effect the Sovereignty Act will have on Alberta, including the petroleum and natural gas industry, Alberta businesses and its federal and interprovincial relationships, including the application of certain federal legislation in Alberta, such as the GGPPA and the IAA and the way in which the Alberta Government may address any legislative and policy gaps created. Although the Sovereignty Act has not yet been challenged in court, it is possible the Sovereignty Act’s constitutionality will be challenged.

The federal government was re-elected in 2019, but in a minority position. Another federal election was held on September 20, 2021 and the federal government was re-elected again in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the petroleum and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial government level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the petroleum and natural gas industry, which effect could prove to be material over time. See “*Industry Conditions – Climate Change Regulation”*, “*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access – Specific Pipeline and Proposed LNG Export Terminal Updates*”, and “*Industry Conditions – The United States Mexico Canada Agreement and other Trade Agreements*”.

Inflation and Cost Management

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 the Corporation's financial performance and funds from operations.

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 funds from operations.

Weakness and Volatility in the Petroleum and Natural Gas Industry

Market events and conditions, including global excess crude oil and natural gas supply, actions taken by OPEC+, sanctions against, and civil unrest in, Iran and Venezuela, slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, conflict between the United States and Iran, isolationist and punitive trade policies, increased United States shale production, sovereign debt levels, world health emergencies (including the COVID-19 pandemic), climate change concerns and political upheavals in various countries, including growing anti-fossil fuel sentiment, have caused significant weakness and volatility in commodity prices. Following extreme supply/demand imbalance in 2020, the crude oil and natural gas industry rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. However, the ongoing war in the Ukraine and price caps and sanctions on oil from Russia have impacted demand and oil prices throughout the latter half of 2022 and are expected to continue throughout the first half of 2023. It is anticipated that the petroleum and natural gas industry will experience more pressure from investors to take meaningful strides towards combating climate change in the upcoming years, including diversifying their energy portfolios. These events and conditions have caused a significant decrease in the valuation of crude oil and natural gas companies and a decrease in confidence in the petroleum and natural gas industry. Such difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Industry Conditions - Royalties and Incentives*", "*Industry Conditions - Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions - Climate Change Regulation*".

In addition, difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the petroleum and natural gas industry in Western Canada and cross-border with the United States has led to additional downward price pressure on crude oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the petroleum and natural gas industry in Western Canada. See "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*".

Project Risks

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

- availability and proximity 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 and natural disasters, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- political uncertainty;
- availability and productivity of skilled labour;
- environmental and Indigenous activism that potentially results in delays or cancellations of projects;
- litigation and judicial interpretation and application of laws, including with respect to indigenous rights and historical treats; and
- regulation of the petroleum and natural gas industry by various levels of government and governmental agencies.

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

Reliance on Skilled Workforce and Key Personnel

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.

There is competition for qualified personnel in the petroleum and natural gas industry 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. Contributions of the existing management team to the immediate and near-term operations of the Corporation are likely to be of central importance. In addition, certain of the Corporation's current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Corporation is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted, which negative impact could prove to be material over time. In addition, the Corporation could experience increased costs to retain and recruit these professionals.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation’s business, financial condition, results of operations and prospects. 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, companies that may operate some of the assets in which the Corporation has an interest may be in or encounter 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 recourse 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 to it 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 effect on the Corporation's financial and operational results.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to crude oil and natural gas, and technological advances in fuel economy and renewable energy generation systems could reduce the demand for crude oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels, commitments to carbon reduction 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 crude oil and natural gas products. The Corporation cannot predict the impact of changing demand for crude oil and natural gas products, and any major changes may have a negative impact on the Corporation's business and financial condition by decreasing the Corporation's revenues, limiting its access to capital and decreasing the value of its assets.

Variations in Foreign Exchange Rates and Interest Rates

World crude 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 crude oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States may indirectly negatively affect the Corporation's revenues, as revenues received by Canadian producers and, similarly, royalties payable to the Corporation, could decrease. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent reserves evaluators. Where the Corporation engages in risk management activities related to foreign exchange rates, there is a potential 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 activities and the cash available to pay dividends, and could negatively impact the market price of the Common Shares, which negative impact could prove to be material over time.

Regulatory

The implementation of new regulations or the modification of existing regulations affecting the petroleum and natural gas industry could reduce demand for crude oil and natural gas and increase costs or make certain projects uneconomic, either of which could materially adversely affect the Corporation's business and financial condition. Further, the ongoing third-party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the petroleum and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access – Specific Pipeline and Proposed LNG Export Terminal Updates*".

In order to conduct crude oil and natural gas operations, third-party lessees and/or operators will require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance the Corporation will be able to obtain all of the permits, licences, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake in the time required or on acceptable terms and conditions. Any failure to renew, maintain or obtain required permits, licences, registrations, approvals and authorizations or the revocation or termination of existing permits, licences, registrations, approvals and authorizations may disrupt such operations and could have a resulting material adverse effect on the Corporation's business and financial condition. In addition, certain federal legislation such as the *Competition Act* (Canada) 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*".

Environmental

All phases of the crude oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and municipal 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 petroleum 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. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties on such lessees or operators, 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 crude 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; however, 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 negative effect on the Corporation's business and financial condition, which negative effect could prove material over time.

Stakeholders, the public and provincial and federal governments are becoming increasingly concerned about habitat and species protection, including degradation to biodiversity caused by economic activity. Accordingly, governments at various levels are increasing the rigour of existing acts and regulations and issuing changes aimed at improving environmental protection. The Corporation and its employees, consultants and operators may disturb the surrounding biodiversity of its properties with the requirement for earth moving and the footprint of crude oil and natural gas operations. This may result in impacts to flora and fauna, including species at risk. Operations on the Corporation's properties may also be affected by conditions or restrictions on operations caused by wildlife habitat and migration patterns, endangered species or species at risk, and vegetation located on the Corporation's properties. The Corporation may fail to achieve necessary permits or be subject to penalties or litigation if they cause habitat destruction or otherwise fail to mitigate impacts on biodiversity on the Corporation's properties. There is no assurance that the Corporation will effectively limit habitat destruction or mitigate the impacts on biodiversity on its properties. If the Corporation fails to do so, there may be decreased activities on the Corporation's properties, which could have an adverse effect on the Corporation's business and financial condition. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation*".

Liability Management

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licencee or permit holder is unable to satisfy its regulatory obligations. Alberta and the AER continue to implement the AB LMF, completing the remaining amendments to the necessary directive and regulations to entirely phase-out the AB LMR Program. The implementation of the AB LMF or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by the Corporation, increased and more frequent financial disclosure obligations or may result in the denial of licence or permit transfers, which could impact the availability of capital to be spent by the Corporation which could in turn materially adversely affect the Corporation's business and financial condition. The impact and consequences of the SCC's Redwater Decision on the AER's rules and policies, lending practices in the petroleum and natural gas industry and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMF may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of crude oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Royalty Regimes

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 could impact the financial condition of the Corporation impacting future capital investment which could reduce the Corporation's business, financial condition, results of operations and prospects. British Columbia introduced a new royalty framework in May 2022 that comes into effect on September 1, 2024, with a number of incentives ending for any wells spudded after September 1, 2022. See "*Industry Conditions – Royalties and Incentives*".

Climate Change

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 and the United States, 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.

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 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. *See "Risk Factors – Non-Governmental Organizations" and "Risk Factors – Reputational Risk".* 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 unfavorable 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 require 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, which negative impact could prove to be material over time.

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" and "Industry Conditions – 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 ability of the Corporation to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather may also increase the risk of personnel injury as a result of dangerous working conditions for the Corporation, its employees and contractors.

Chronic Physical Climate Change Risks

The Corporation's operations and activities associated with the Corporation's projects and assets emit GHGs which may require the Corporation to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effects could prove material over time. There is no guarantee the current provincial regimes in place will continue to meet federal stringency requirements and their continued application is subject to achieving the stringency standards as required by the federal government.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian petroleum and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Corporation to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety, which may in turn have a negative effect on the Corporation's production which negative effect could prove material over time. Specifically, in the event of water shortages or sourcing issues, the Corporation may not be able to, or will incur greater costs to, carry out hydraulic fracturing.

Concerns over climate change, fossil fuels, GHG emissions and water and land-use could lead to reduced demand for the crude oil, natural gas and NGLs, which would have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See "*Risk Factors – Alternatives to and Changing Demand for Petroleum Products"*.

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

Acute Physical Climate Change Risks

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict or could interfere with the Corporation's operations, increasing costs and negatively impacting the lessee or operator's production.

Over the last several years, certain areas of British Columbia, Alberta and Saskatchewan have been negatively impacted by wildfires and, most recently with extreme flooding in British Columbia, causing temporary interruption to both pipeline systems and railway lines. Extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced crude oil and natural gas as well as goods and services in their supply chains and meet demand due to temporary interruptions.

Certain of the Corporation's operations are located in locations that are proximate to forests and rivers and a wildfire or flood, respectively, may lead to significant downtime and/or damage to such assets which may affect production. At this time, the Corporation is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting the Corporation's operations.

Hydraulic Fracturing

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

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 to take 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.

Additionally, the Corporation must dispose of the fluids produced from crude oil, NGL 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. See "*Risk Factors – Disposal of Fluids Used in Operations"*.

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

Seismic events are common in certain parts of Alberta and are generally clustered around the municipalities of Red Deer, Cardston, Fox Creek and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek and the Red Deer region, the AER introduced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay formation in the Fox Creek area in February 2015 and subsequently in the Red Deer region in December 2019. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events and the suspension of operations if a seismic event above a particular threshold occurs. These requirements remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

British Columbia

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. On February 20, 2019, the panel published its final report. The panel made 97 recommendations, primarily focused on addressing knowledge gaps and concerns regarding environmental impacts of hydraulic fracturing. Overall, the panel concluded that British Columbia's current regulations were robust; however, the implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect the Corporation's business operations and financial condition.

Due to seismic activity recorded in the Kiskatinaw Area, in May 2018, the BC Commission issued special notification and monitoring requirements for hydraulic fracturing operators in the Kiskatinaw Area. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the BC Commission, and the suspension of operations if a seismic event above a 3.0 magnitude occurs. In November 2018, seismic activity near Fort St. John in the Kiskatinaw Area resulted in the suspension of several companies' operations, demonstrating the BC Commission's willingness to enforce these enhanced regulatory requirements. The BC Commission continues to monitor seismic events across the province and may implement similar requirements in other areas if necessary.

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams which companies have built in association with their hydraulic fracturing operations. Under the Water Sustainability Act, dams require a water licence. For dams over a certain size, dam-operators must comply with additional safety and reporting requirements set out in the Dam Safety Regulation. Larger dams are also subject to an environmental assessment and approval under the Environmental Assessment Act. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization.

While the BC Commission has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent, the relevant industry regulators will respond to this issue.

The Corporation may face operational delays if found to be not strictly compliant with the current regulatory framework.

Energy Transition

Globally, there is an increasing focus on transitioning to a low-carbon economy resulting in a number of policies and initiatives designed to shift resources and investment away from fossil fuels towards low carbon sources. This includes government regulations that restrict the production and consumption of fossil fuels such as zero emission vehicle mandates, prohibitions on plastic use, and fuel efficiency standards. Government subsidies directed towards new low-carbon technologies or to businesses providing products and services that reduce consumer demand for fossil fuels may also result in a broader reduction in the global economy's reliance on fossil fuels. In addition, shifting consumer preferences towards low-carbon products and services are also driving investment in technologies and products that reduce fossil fuel consumption. The Corporation is constantly evaluating its options with respect to increasing environmental efficiency through its operations. However, there can be no assurances that the Corporation will be able to predict any such market trends or consumer preferences. Accordingly, there is a risk that the nature of the global energy transition materially adversely affects the Corporation's business and financial condition.

Waterflood

The Corporation may undertake or intend 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 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 they may not be able to undertake waterflooding activities, which may reduce the amount of crude oil and natural gas that the Corporation will ultimately receive 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 business, financial condition, results of operations and prospects.

Disposal of Fluids used in Operations

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

Title to Assets

Although title reviews may be conducted prior to the purchase of fee simple mineral title interests or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise to defeat the Corporation's claim. The Corporation’s actual interest may, therefore, vary from the records previously maintained by the prior owners. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which could materially adversely affect the Corporation's business, financial condition, results of operations and prospects.

There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties that the Corporation controls that, if successful or made into law, could impair our interests in the oil and natural gas properties that it controls and impact the Corporation's business, financial condition, results of operations and prospects.

Non-Governmental Organizations

The petroleum and natural gas industry may, at times, be subject to public opposition. The oil and natural gas industry has become increasingly politically polarizing in Canada, which has resulted in civil disobedience surrounding oil and natural gas development, particularly with respect to infrastructure projects. 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 which may include Indigenous groups, landowners, environmental interest groups (including those opposed to crude oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences, and direct legal challenges, including the possibility of climate-related litigation (see "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*"). There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require significant and unanticipated capital and operating expenditures which may negatively impact the Corporation's business, financial condition, results of operations and prospects, which negative impact could prove to be material over time.

Availability and Cost of Material and Equipment

Crude 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 areas where such activities will be conducted. The availability of such material and equipment is limited. The oil and natural 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. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation's operations and may delay such exploration, development and operating activities, which, in turn, could materially adversely affect the Corporation's business and financial condition.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system, which was upheld by the SCC as constitutional, currently applies in provinces and territories without their own system that meets federal stringency standards and provinces with their own system are subject to continued compliance with the federal system. There is no guarantee that a province with a system that currently applies will meet, or continue to meet federal stringency standards. See "*Industry Conditions – Climate Change Regulation*".

Any taxes placed on carbon emissions may have the effect of decreasing the demand for crude oil and natural gas products and at the same time, increasing the operating expenses of crude oil and natural gas companies, each of which may have a material adverse effect on the Corporation's revenue.

Further, the imposition of carbon taxes puts companies at an economic disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused on oil and natural gas production, exploration and development in the Corporation's Sparky, Southeast Saskatchewan, Manitoba, Carbonates, Valhalla, Shaunavon and Minors regions. In the future, the Corporation may acquire or move into new industry-related activities or new geographical areas or may acquire different energy-related assets, and as a result, the Corporation may face unexpected risks or alternatively, the Corporation's 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 condition being adversely affected.

Insurance

Although the Corporation maintains insurance in accordance with industry standards to address certain risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of 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 or retentions 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.

Expiration of Licences and Leases

Certain of the Corporation's properties are held in the form of licences and leases and working interests in licences and leases held by others. If the Corporation or the holder of the licence or lease fails to meet the specific requirements 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 these licences or leases or the working interests relating to a licence or lease may impair certain of the Corporation's properties and in turn may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to property damage, personal injury, property tax, land rights, royalty rights, access rights, environmental issues and lease or contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty, may be determined adversely to the Corporation and could have a material adverse effect on the Corporation's business, financial condition and funds from 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 effect on the Corporation's business and financial condition.

Indigenous Claims

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets.

However, if a claim arose and was successful, such claim may have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Moreover, in recent years there has been increasing litigation regarding historical treaties with Indigenous peoples in Canada. Judicial interpretation of such historical treaties, and in particular the rights granted thereunder to Indigenous nations to manage and use the lands in a manner consistent with their ancestral practices, may impact future resource and industrial development in and around these lands. While the potential impact of current and future judicial decisions is uncertain at this time, it is possible that such decisions may have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of 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. Acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments. These assessments include a number of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geological, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

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. The Corporation may also enter into other industry-related activities or new geographical areas or acquire different energy-related assets that may result in unexpected or significantly increased risk to the Corporation, which could materially adversely affect the Corporation's business, financial condition, results of operations and prospects. Management continually assesses the value and contribution of the various properties and assets within its portfolio. In this regard, the Corporation may consider disposing of certain non-core assets in-order to focus its efforts and resources more efficiently. Depending on market conditions for such non-core assets, the Corporation may realize less on disposition of certain core assets than their carrying value on the financial statements of the Corporation.

Industry Competition

The petroleum and natural gas industry is competitive throughout its lifecycle. The Corporation competes with numerous other entities in the search for, the acquisition of and the development of petroleum and natural gas properties, access to drilling and service rigs and other equipment, access to transportation, access to skilled and technical operating personnel and in the marketing of petroleum and natural gas. Other companies may have access to substantially greater financial resources, staff and facilities than those of the Corporation and who may have lower costs of, and better access to, capital.

The Corporation's ability to increase its reserves in the future will depend partially on its ability to explore and develop its present properties, but will also depend on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling.

Management of Growth and Integration

The Corporation may be subject to both transition and growth-related risks, including capacity constraints and pressure on its internal systems and controls. In particular, the Corporation is responsible for managing a substantial number of land and title documents and related accounting functions that require significant employee resources. The ability of the Corporation to manage future growth and integration of additional lands, leases and acquisitions effectively requires it to continue to implement and improve financial and land systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this integration and growth may have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Reserves Estimates

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 AIF are estimates only. Generally, estimates of economically recoverable crude oil and natural gas reserves (including the breakdown of reserves by product type) and the future net cash flows from such estimated reserves which are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- commodity prices;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures by the working interest owners thereon;
- marketability of crude 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 these reasons, estimates of the economically recoverable crude oil, natural gas and NGL 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 net production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, Sproule, the Corporation's independent qualified 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 crude oil and natural gas, curtailments or increases in consumption by crude 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 crude oil, natural gas and NGL reserves will vary from the estimates contained in the Reserves Report and such variations could be material. The Reserves Report is effective as of December 31, 2022, with a preparation date of February 15, 2023, and, except as may be specifically stated or required by applicable securities laws, has not been updated and, therefore, does not reflect changes in reserves since that date.

Market Price of Common Shares

The trading price of the securities of crude oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the crude oil and natural gas market. This includes, but is not limited to, changing and in some cases, negative investor sentiment towards energy-related businesses. In recent years, the volatility of crude oil and natural gas commodity prices, and the securities of issuers involved in the crude oil and natural gas business, has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. Similarly, recent market prices in the securities of crude oil and natural gas issuers relative to other industry sectors have led to lower crude oil and natural gas representation in certain key equity market indices. The volatility, trading volume and market price of crude oil and natural gas have been impacted by increasing investment levels in passive funds that track major indices and only purchase securities included in such indices and subsequently dispose of those securities if they are excluded from such indices. In addition, many institutional investors, pension funds and insurance companies, including government sponsored entities, have implemented investment strategies increasing their investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments. These factors have impacted the volatility and liquidity of certain securities and put downward pressure on the market 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 will trade cannot be accurately predicted.

Capital and Additional Funding Requirements

The Corporation's cash flow from its properties may not be sufficient to fund its ongoing activities at all times, and from time to time the Corporation may require additional financing, which may include financing for the acquisition of crude oil and natural gas assets. Future capital and other expenditures will be financed out of cash generated from operations, borrowings and possible future equity issuances and the Corporation's ability to do so will be dependent on, among other factors: the overall state of the capital markets; commodity prices; the Corporation's credit rating (if applicable); commodity prices; interest 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. Due to the conditions in the petroleum and natural gas industry and/or 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. The current conditions in the petroleum and natural gas industry have negatively impacted the cost and/or ability of crude oil and natural gas companies to access additional financing.

There can be no assurance that debt or equity financing, or cash flow 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.

Alternatively, any available financing may be highly dilutive to existing shareholders. There is risk that if the economy and banking industry experience unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected. The inability of the Corporation to access sufficient capital for its operations could cause the Corporation to, amongst other things, miss certain acquisition opportunities and may materially adversely affect the Corporation's business and financial condition.

Changing Investor Sentiment

A number of factors, including the effects of the use of fossil fuels on climate change, GHG emissions reduction, the impact of crude 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 petroleum 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 crude oil and natural gas properties or companies tied to crude oil and natural gas or are reducing the amount of their investments of such entities over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices, including the use of environmental metrics in executive compensation. Developing and implementing such policies and practices can be costly 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 petroleum 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 Common Shares, even if the Corporation's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Corporation's assets which may result in an impairment charge.

Evolving Corporate Governance, Sustainability and Reporting Framework

The Corporation's business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of noncompliance, which could have an adverse effect on the price of the Corporation's securities. The Corporation is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities administrators, the TSX and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity making compliance more difficult and uncertain. Further, the Corporation's efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

Reputational Risk

The Corporation's business, financial condition, operations or prospects may be negatively impacted, which negative impact could prove to be material over time, as a result of any negative public opinion toward the Corporation or as a result of any negative sentiment toward or in respect of 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 crude 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 licences and increased costs and/or cost overruns.

Any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage the reputation of and, in turn, the Corporation, in the areas in which the Corporation operates. Negative sentiment towards the Corporation could result in a lack of willingness of governmental authorities to grant the necessary licences or permits for the Corporation to operate its business. In addition, negative sentiment towards the Corporation could result in the residents of the areas where the Corporation is doing business opposing further operations in the area by the Corporation. The Corporation's reputation could be affected by actions and activities of other corporations operating in the petroleum and natural gas industry, over which the Corporation has no control. If the Corporation, either directly or indirectly develops a reputation of having an unsafe workplace 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 crude oil and natural gas development and the possibility of climate related litigation against fossil fuel companies may indirectly harm the Corporation's reputation.

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.

Cost of New Technologies

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

Dividends

The amount of future cash dividends paid by the Corporation is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices; production levels; financial condition of the Corporation; results of operations; capital expenditure requirements; working capital requirements; operating costs; current and expected future levels of earnings; liquidity requirements; market opportunities; income taxes; debt repayments; legal, regulatory, and contractual constraints; the Corporation's risk management activities or programs; the Corporation's business plan, strategies and objectives; tax laws; foreign exchange rates; interest rates; and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which are beyond the control of the Corporation, the Corporation's dividend policy and, as a result, future cash dividends, could be reduced or suspended entirely, from time to time. The Credit Facilities may prohibit the Corporation from paying dividends at any time at which a default or event of default has occurred and is continuing, or if a default or event of default would exist as a result of paying the dividend.

Over time, the Corporation's capital and other cash needs may change significantly from its current needs, which could affect whether the Corporation pays dividends and the amount of dividends, if any, it may pay in the future. If the Corporation continues to pay dividends at the current levels, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn. The Board may amend, revoke or suspend the Corporation's dividend policy at any time. A decline in the market price, liquidity, or both, of the Common Shares could result if the Corporation reduces or eliminates the payment of dividends, which could result in losses to shareholders.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Corporation and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which may result from lower commodity prices and/or lower royalty production volumes, and any decision by the Corporation to finance capital expenditures using funds from operations.

To the extent that external sources of capital, including in exchange for the issuance of additional Common Shares, become limited or unavailable, the ability of the Corporation to make the necessary acquisitions to maintain or expand petroleum and natural gas reserves will be impaired. To the extent that the Corporation is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Foreign Exchange Risk on Dividends

The Corporation's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders, and shareholders who calculate their return in currencies other than the Canadian dollar, are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to the shareholder's home currency.

Additional Taxation Applicable to Dividends Paid to Non-Residents

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Where a non-resident is a United States resident entitled to benefits of the Canada-United States Income Tax Convention, 1980 and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%. In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

Hedging

The Corporation may enter into hedging arrangements to fix interest rates applicable to the Corporation's debt. However, if interest rates decrease as compared to the interest rate fixed by the Corporation, the Corporation will not benefit from the lower interest rate.

The Corporation may enter into agreements to receive fixed prices on its crude oil and natural gas royalty production volumes, if any, to offset the risk of revenue losses if commodity prices decline.

Similarly, the Corporation may enter into agreements to fix the differential or discount pricing gap which exists and may fluctuate been different grades of crude oil, NGL and natural gas and the various market prices received for such products. 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, if the Corporation enters into hedging arrangements it may be exposed to the risk of financial loss in certain circumstances, including instances in which:

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

Income Taxes

The Corporation files all required income tax returns in order to be 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, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the petroleum 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.

Issuance of Debt

From time to time, the Corporation may finance its activities (including potential future crude oil and natural gas royalty asset acquisitions) in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for peers of similar size. Additional debt financing 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.

Competition

The petroleum and natural gas industry is highly competitive in all of its phases. The Corporation competes with numerous other entities for land, acquisition of reserves, access to drilling and service rigs and other equipment, access to transportation and access to skilled technical and operating personnel, among other things. The Corporation's competitors include other companies who may have more financial resources, staff or political influence than the Corporation.

Conflicts of Interest

Certain members of the Board and management are also, or may in the future be, directors or officers of other crude oil and natural gas companies, that may compete or be counterparties to agreements with the Corporation 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 and Corporation policies 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, or material transaction, or proposed material transaction, with the Corporation disclose their 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. The Corporation also has additional policies in place providing guidance as to how officers and directors are to manage conflicts of interest.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information by the Corporation, 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 solely in monetary 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.

Information Technology Systems and Cyber-Security

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its 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 its land base, manage financial resources, analyze seismic information, administer its contracts with its operators and lessees and communicate with employees and third-party operators.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or its 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.

Despite the Corporation's efforts to mitigate such cyber-phishing attacks through education and training, phishing activities remain a serious problem that may damage our 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 reputation, performance and earnings, which negative effect could prove to be material over time, 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, results of operations and prospects.

Social Media

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. As social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Corporation may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Limited Ability of Residents in the United States to Enforce Civil Remedies

The Corporation is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All of our directors, except for Robert Leach, and all of our officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all of our assets and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against the Corporation or against any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Negative Impact of Additional Sales or Issuances of Common Shares

The Board may issue an unlimited number of Common Shares without any vote or action by the shareholders, subject to the rules of any stock exchange on which the Corporation's securities may be listed from time to time. The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities. If the Corporation issues any additional equity, the percentage ownership of existing shareholders will be reduced and diluted and the price of the Common Shares could decline.

Forward-Looking Information

Shareholders and prospective investors are cautioned not to place undue reliance on Surge’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 outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2022, there were (i) no penalties or sanctions imposed against the Corporation 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 the Corporation that it believes would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

James Pasieka, a director of the Corporation, and Michael Bennett, the Corporate Secretary of the Corporation, are, respectively, counsel to and a partner of the national law firm McCarthy Tétrault LLP, which law firm renders legal services to the Corporation.

Except as disclosed above or as may be disclosed elsewhere in this AIF, none of the directors, executive officers or principal shareholders of the Corporation, and no associate or affiliate of any of them, has or has had any material interest in any transaction or any proposed transaction which has materially affected or is reasonably expected to materially affect the Corporation or any of its affiliates.

AUDITOR, TRANSFER AGENT AND REGISTRAR

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

The transfer agent and registrar for the Common Shares is Odyssey Transfer Agent & Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario.

INTEREST OF EXPERTS

The Reserves Report and certain reserves estimates contained in filings made by the Corporation under NI 51-102 during the year ended December 31, 2022 were prepared by Sproule. As at the date of this Annual Information Form, the directors, officers, employees and consultants of Sproule who participated in the preparation of the Reserves Report or such reserves estimates or who were in a position to directly influence the preparation or outcome of the preparation of the Reserves Report or such reserves estimates, as a group, owned, directly or indirectly, less than 1 percent of the outstanding Common Shares.

KPMG LLP are independent of the Corporation pursuant to the rules of professional conduct of the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information concerning the Corporation may be found under the Corporation's profile on SEDAR at www.sedar.com. Additional information, including information concerning directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, will be contained in the information circular of the Corporation for the annual general meeting of the holders of Common Shares scheduled to be held in 2023. Additional financial information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2022.

SCHEDULE "A"

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of Surge Energy Inc (the "Company"):

1. We have evaluated the Company'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 Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following table 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 Company 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 Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	December 31, 2022	Canada				
Total			**Nil**	**2,510,802**	**Nil**	**2,510,802**

6. In our opinion, the reserves data 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.

7. 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 Surge Energy Inc. (As of December 31, 2022)".

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta

"Original signed by Matthew Tymchuk, P.Eng."

Matthew Tymchuk, P.Eng
Team Lead, Engineering
Sproule Associates Limited
DATE: Feb. 21, 2023 APEGA Permit Number 00417

"Original signed by Gary R. Finnis, P.Eng."

Gary R. Finnis, P.Eng.
Senior Manager, Engineering
DATE: Feb. 21, 2023 **RM APEGA ID #:** 62965

SCHEDULE "B"

FORM 51-101F3
Report of Management and Directors on Reserves Data and Other Information

Terms to which a meaning is ascribed in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities have the same meaning herein.

Management of Surge Energy Inc. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

Sproule Associates Limited, an independent qualified reserves evaluator, has evaluated and reviewed the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "A" to the Annual Information Form of the Corporation for the year ended December 31, 2022 (the "**AIF**").

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

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

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

(c) reviewed the applicable reserves data with management and with Sproule Associates Limited.

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

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

(b) the filing of Form 51-101F2, which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "Paul Colborne"	*(signed) "Jared Ducs"*
Paul Colborne, President & Chief Executive Officer	Jared Ducs, Chief Financial Officer
(signed) "Daryl Gilbert"	*(signed) "P. Daniel O'Neil"*
Daryl Gilbert, Director & Chair of the Reserves Committee	P. Daniel O'Neil, Director

March 8, 2023

SCHEDULE "C"

Audit Committee Charter

SURGE ENERGY INC

AUDIT COMMITTEE CHARTER

Role and Objective

The Audit Committee is a committee of the Board of Directors of Surge Energy Inc. (the "**Corporation**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited consolidated financial statements and other mandatory disclosure releases containing financial information of the Corporation. The objectives of the Audit Committee are as follows:

1. to assist directors in fulfilling their legal and fiduciary obligations (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. to oversee the audit efforts of the external auditors of the Corporation;

3. to maintain free and open means of communication among the directors, the external auditors, the financial and senior management of the Corporation;

4. to satisfy itself that the external auditors are independent of the Corporation; and

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

The function of the Committee is one of oversight of management and the external auditors in the execution of their responsibilities. Management is responsible for the preparation, presentation and integrity of the financial statements of the Corporation, maintaining appropriate accounting and financial reporting principles and policies and implementing appropriate internal controls and procedures. The external auditors are responsible for planning and carrying out a proper audit of the annual financial statements of the Corporation and reviewing the interim financial statements of the Corporation prior to their filing with securities regulatory authorities and other procedures.

Composition of the Committee

1. The Audit Committee shall consist of at least three directors. The Board shall appoint one member of the Audit Committee to be the Chair of the Audit Committee.

2. Each director appointed to the Audit Committee by the Board must be independent. A director is independent if the director has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board, reasonably interfere with the exercise of the director's independent judgment. In determining whether a director is independent of management, the Board shall make reference to National Instrument 52-110 – Audit Committees or the then current legislation, rules, policies and instruments of applicable regulatory authorities.

3. Each member of the Audit Committee shall be "financially literate". In order to be financially literate, a director must be, at a minimum, able to read and understand financial statements that present a breadth and complexity of accounting issues generally comparable to the breadth and complexity of issues expected to be raised by the Corporation's financial statements.

4. A director appointed by the Board to the Audit Committee shall be a member of the Audit Committee until replaced by the Board or until his or her resignation.

Meetings of the Committee

1. The Audit Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chair of the Audit Committee and whenever a meeting is requested by the Board, a member of the Audit Committee, the auditors, or a senior officer of the Corporation. Meetings of the Audit Committee shall correspond with the review of the interim financial statements and management discussion and analysis of the Corporation.

2. Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee. The auditors shall be given notice of each meeting of the Audit Committee at which financial statements of the Corporation are to be considered and such other meetings as determined by the Chair and shall be entitled to attend each such meeting of the Audit Committee.

3. Notice of a meeting of the Audit Committee shall:

   (a) be in writing;

   (b) state the nature of the business to be transacted at the meeting in reasonable detail;

   (c) to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and

   (d) be given at least two business days prior to the time stipulated for the meeting or such shorter period as the members of the Audit Committee may permit.

4. A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee. However, it shall be the practice of the Audit Committee to require review, and, if necessary, approval of certain important matters by all members of the Audit Committee.

5. A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

6. In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.

7. The Chairman of the Board, senior management of the Corporation and other parties may attend meetings of the Audit Committee; however the Audit Committee (i) shall meet with the external auditors independent of management as necessary, in the sole discretion of the Committee, but in any event, not less than quarterly; and (ii) may meet separately with management.

8. Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting.

Duties and Responsibilities of the Committee

1. It is the responsibility of the Audit Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Audit Committee.

2. The Audit Committee shall, in the exercise of its powers, authorities and discretion so authorized, conform to any regulations or restrictions that may from time to time be made or imposed upon it by the Board or the legislation, policies or regulations governing the Corporation and its business.

3. It is the responsibility of the Audit Committee to satisfy itself on behalf of the Board that the Corporation's system of internal controls over financial reporting and disclosure controls and procedures are satisfactory for the purpose of:

   (a) identifying, monitoring and mitigating the principal risks;

   (b) ensuring compliance with legal, ethical and regulatory requirements;

   and to review with the external auditors their assessment of the internal controls over financial reporting and the disclosure controls of the Corporation, their written reports containing recommendations for improvement, and management's response and any follow-up to any identified weaknesses.

4. It is the responsibility of the Audit Committee to review the annual financial statements of the Corporation and, if deemed appropriate, recommend the financial statements to the Board for approval. This process should include but be not to be limited to:

   (a) reviewing and accepting, if appropriate, the annual audit plan of the external auditors of the Corporation, including the scope of audit activities, and monitor such plan's progress and results during the year;

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

   (c) reviewing significant accruals, reserves or other estimates such as any impairment calculation;

   (d) reviewing the methods used to account for significant unusual or non-recurring transactions;

   (e) ascertaining compliance with covenants under loan agreements;

   (f) reviewing disclosure requirements for commitments and contingencies;

   (g) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

   (h) reviewing unresolved differences between management and the external auditors;

   (i) obtain explanations of significant variances with comparative reporting periods;

   (j) review of business systems changes and implications;

   (k) review of authority and approval limits;

   (l) review the adequacy and effectiveness of the accounting and internal control policies of the Corporation and procedures through inquiry and discussions with the external auditors and management;

(m) confirm through private discussion with the external auditors and the management that no management restrictions are being placed on the scope of the external auditors' work;

(n) review of tax policy issues;

(o) review of emerging accounting issues that could have an impact on the Corporation; and

(p) understand bias in decision-making and areas where significant judgment is applied.

5. It is the responsibility Audit Committee to review the interim financial statements of the Corporation and, if deemed appropriate, to recommend the financial statements to the Board for approval and to review all related management discussion and analysis. The Audit Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of all other financial information and shall periodically assess the accuracy of those procedures.

6. The Audit Committee shall have the authority to:

(a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;

(b) discuss with the management and senior staff of the Corporation, its subsidiaries and affiliates, any affected party and the external auditors, such accounts, records and other matters as any member of the Audit Committee considers necessary and appropriate;

(c) engage independent counsel and other advisors as it determines necessary to carry out its duties; and

(d) to set and pay the compensation for any advisors employed by the Audit Committee.

7. With respect to the appointment of external auditors by the Board, the Audit Committee shall:

(a) recommend to the Board the appointment of the external auditors;

(b) review the performance of the external auditors and make recommendations to the Board regarding the replacement or termination of the external auditors when circumstances warrant;

(c) oversee the independence of the external auditors by, among other things, requiring the external auditors to deliver to the Audit Committee, on a periodic basis, a formal written statement delineating all relationships between the external auditors and the Corporation and its subsidiaries;

(d) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee; and

(e) 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.

8. Audit Committee shall review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

9. The Audit Committee must pre-approve all non-audit services to be provided to the Corporation or its subsidiaries by external auditors. The Audit Committee may delegate, to one or more members, the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting and such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

10. The Audit Committee shall review the Enterprise Risk Management framework and procedures of the Corporation (i.e. hedging, litigation and insurance), including the annual review of insurance coverage and make appropriate recommendations to the Board with respect thereto.

11. The Audit Committee shall receive regular updates with respect to information technology matters, including with respect to the Corporation's cyber security programs to address potential cyber-related risks.

12. The Audit Committee shall establish and maintain procedures for:

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

    (b) the confidential, anonymous submission by employees of the Corporation of concerns in accordance with the Corporation’s Whistleblower Policy.

13. The Audit Committee shall review and approve the Corporation’s hiring policies regarding employees and former employees of the present and former external auditors or auditing matters.

14. The Chairman of the Audit Committee shall review and approve the expenses incurred by the President and Chief Executive Officer.

15. The Audit Committee shall periodically report the results of reviews undertaken and any associated recommendations to the Board.

16. The Audit Committee shall assess, on an annual basis, the adequacy of this Mandate and the performance of the Audit Committee.