SURGE ENERGY INC

Annual Information Form

For the Year Ended December 31, 2024
Dated March 5, 2025

Table of Contents

Select Definitions 3
Abbreviations and Conversion 5
Non-GAAP Measures 6
Notes on Reserves Data and Other Oil and Natural Gas Information 6
Special Note Regarding Forward Looking Statements 9
Surge Energy Inc. 11
Development of the Business 12
Description of the Business 13
Principal Producing Properties 15
Statement of Reserves Data 17
Description of Capital Structure 27
Dividend Policy 31
Market for Securities 33
Directors and Officers 34
Audit Committee 38
Industry Conditions 39
Risk Factors 66
Material Contracts 96
Legal Proceedings And Regulatory Actions 96
Interest of Management and Others in Material Transactions 96
Auditor, Transfer Agent and Registrar 96
Interest of Experts 97
Additional Information 97

Schedule “A” – Form 51-101F2
Schedule “B” – Form 51-101F3
Schedule “C” – Audit Committee Charter

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, 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;

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

"**Credit Agreement**" means the fourth amended and restated credit agreement dated as of September 5, 2024 by and among Surge, as borrower, National Bank of Canada, as administrative agent, and the financial institutions party thereto from time to time as lenders, as amended on October 11, 2024 and December 17, 2024 and as may be further amended from time to time;

"**Credit Facility**" means the aggregate $250 million first lien secured credit facilities of the Corporation with a syndicate of lenders, comprised of a $200 million revolving credit facility and a $50 million operating credit facility, as more particularly described under the heading "*Description of Capital Structure – Credit Facility*";

"**Current Market Price**" means, generally, the volume weighted average trading price of the Common Shares for the applicable period, on the TSX (or if the Common Shares are no longer traded on the TSX, on such other exchange as the Common Shares are then traded) for the 20 consecutive trading days ending on the fifth trading day preceding the applicable date. If the Common Shares are not listed or quoted on the TSX or another securities exchange or market, "**Current Market Price**" shall be the fair value of a Common Share as reasonably determined by the Board of Directors;

"**Debenture Indenture**" means the debenture indenture dated November 15, 2017 between Surge and Computershare Trust Company of Canada, as amended on June 30, 2018 and as supplemented by a first supplemental debenture indenture dated May 8, 2019 and a second supplemental debenture indenture dated October 19, 2023, under which the Debentures were issued;

"**Debentures**" means the 8.50 percent convertible unsecured subordinated debentures due on December 31, 2028, as more particularly described under the heading "*Description of Capital Structure - Debentures*";

"**GAAP**" means generally accepted accounting principles for Canadian public companies, which are currently IFRS Accounting Standards;

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

"**NGL**" means natural gas liquids;

"**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*;

"**NI 52-112**" means National Instrument 52-112 – *Non-GAAP and Other Financial Measures Disclosure*;

"**Reserves Report**" means the independent engineering report with a preparation date of February 7, 2025 and effective December 31, 2024 prepared by and containing the evaluation of Sproule of the oil, NGL and natural gas reserves attributable to the properties of the Corporation;

"**Senior Notes**" means the 8.50 percent senior unsecured notes due on September 5, 2029, as more particularly described under the heading "*Description of Capital Structure – Senior Notes*";

"**Senior Notes Indenture**" means the trust indenture dated September 5, 2024 between Surge and Odyssey Trust Company of Canada, under which the Senior Notes were issued;

"**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 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-GAAP MEASURES

This AIF includes references to a financial measure, “operating netback”, which is not defined by IFRS and therefore constitutes a non-GAAP financial measure, as defined in NI 52-112. 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. As used in this AIF, “operating netback” may not be comparable to “operating netback” or other performance measures presented by other issuers. 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 “operating netback” should not be construed as an alternative to either net income or 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;
- expectations and assumptions concerning the performance of existing wells and success obtained in drilling new wells;
- 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;
- ability of Surge to meet its objectives;
- Surge's ability to fund future capital requirements and the nature and source of such funding;
- 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 any new pandemic or epidemic and other international or geopolitical events, including government responses related thereto and their impact on global energy pricing, oil and gas industry exploration and development activity levels and production volumes;
- the condition of the global economy, including trade, public health and other geopolitical risks (including the Russian invasion of Ukraine and continued conflict in the Middle East);
- changes with respect to foreign and domestic trade policy;
- the imposition or expansion of tariffs imposed by domestic and foreign governments or the imposition of other restrictive trade measures, retaliatory or countermeasures implemented by such governments, including the introduction of regulatory barriers to trade and the potential effect on the demand and/or market price for Surge's products and/or otherwise adversely affects Surge;
- uncertainties associated with estimating oil and natural gas reserves and production levels;
- uncertainty surrounding the amount that will be available under the Credit Facility in the future and the ability to obtain approval from the syndicate to increase or maintain its credit facilities;
- 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, environmental laws and incentive programs relating to the oil and gas industry;
- the impact of 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 and assumptions 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 a consolidation of the Common Shares. 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.

As at December 31, 2024 and as the date of this AIF, Surge has no subsidiaries.

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 symbol "SGY.DB.B".

Three Year History

The significant activities of the Corporation over the last three completed financial years that have influenced the general development of its business are as set forth below:

Year Ended December 31, 2022

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

Year Ended December 31, 2023

On October 19, 2023, Surge issued $48.3 million principal amount of Debentures. The Debentures will mature and be repayable on December 31, 2028 and accrue interest at a rate of 8.50 percent per annum. The Debentures are listed on the TSX under the symbol "SGY.DB.B". See "*Description of Capital Structure - Debentures*".

On November 18, 2023 (the "**Series 2 Redemption Date**"), Surge redeemed all of the outstanding 6.75 percent convertible unsecured subordinated debentures originally due on June 30, 2024, paying the aggregate principal amount of such debentures (being $1,000 per debenture) plus all unpaid interest thereon to, but excluding the Series 2 Redemption Date. These debentures, which had traded on the TSX under the symbol "SGY.DB.A", were delisted from the TSX immediately following the Series 2 Redemption Date.

Year Ended December 31, 2024

In May 2024, Surge completed sales of certain non-core assets in Central Alberta and Southwest Saskatchewan, located at Shaunavon and Westerose, respectively, for aggregate net proceeds of approximately $37.0 million.

On June 14, 2024, Surge announced that the TSX accepted its notice of intention to make a normal course issuer bid (the "**NCIB**") for its outstanding Common Shares, in accordance with the rules and policies of the TSX. The NCIB allows Surge to repurchase up to 9,781,079 Common Shares (representing approximately 10 percent of the 97,810,793 issued and outstanding Common Shares that comprised the public float as of June 10, 2024) over a period of 12 months commencing on June 19, 2024. The NCIB expires no later than

June 18, 2025. Pursuant to the NCIB, during 2024, Surge repurchased for cancellation 1,822,200 Common Shares for approximately $11.0 million at a weighted average price of $6.02 per Common Share.

On September 5, 2024, Surge issued $175 million principal amount of Senior Notes, pursuant to a private placement offering. The Senior Notes will mature and be repayable on September 5, 2029 and accrue interest at a rate of 8.50 percent per annum. See "*Description of Capital Structure – Senior Notes*".

On December 19, 2024, Surge completed the sale of certain gas weighted non-core assets in the Valhalla area of Alberta, for cash proceeds of approximately $9.5 million. As part of the sale, the purchaser assumed all future abandonment and reclamation obligations pertaining to the non-core assets.

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, 2024.

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's strategy is focused on the development of high quality conventional oil reservoirs with proven technology and enhanced recovery techniques; the strategic allocation of capital to highest rate of return opportunities; and the positive impact the communities in which it operates.

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.

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 business, financial condition, results of operations and prospects 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 adverse effect 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, 2024, the Corporation has recorded an asset retirement obligation of $292 million. The Corporation anticipates that the expenditures necessary to satisfy the asset retirement obligation will be incurred over a period of approximately 50 years, with the majority of the expenditures being incurred from years 2025 to 2050. 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, 2024, see the Corporation's audited annual financial statements for the year ended December 31, 2024, which have been filed on SEDAR+ and may be viewed under the Corporation's profile at www.sedarplus.com. See "*Risk Factors – Hedging*".

Personnel

As at December 31, 2024, the Corporation had 78 head office employees and 5 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.

The Environment and Safety Committee is responsible for developing the Corporation's approach to, among others, matters concerning health, safety and the environment, and, from time-to-time, to review and make recommendations to the Board as to such matters. With respect to health, safety and environmental matters, the Environment and Safety Committee reviews the Corporation's policies, programs and internal control systems regarding health, workforce safety, asset integrity, process safety and environmental protection and monitors the Corporation's performance relative to internal improvement objectives and industry practices. Further, the Environment and Safety Committee reviews the Corporation's policies, programs and internal control systems with respect to field operations and monitors the Corporation's field operating capabilities, field operating practices and process safety practices.

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 2024, Surge continued its commitment to environmental, social and governance spending initiatives by spending an aggregate of $15.2 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 two core areas: Sparky and Southeast Saskatchewan. The Corporation additionally holds interests in certain other non-core areas in Alberta, Saskatchewan and Manitoba which are described under "Carbonates", "Minors" and "Manitoba", below. A general description of each of these properties as at December 31, 2024 is provided below.

Sparky

As at December 31, 2024, Surge's principal properties in Sparky include the Lloyd/Cummings waterfloods at Giltedge, Silver, and Provost. In Sparky, Surge held an average working interest of approximately 91 percent in approximately 76,811 gross (70,183 net) developed acres and an average working interest of approximately 96 percent in approximately 52,577 gross (50,693 net) undeveloped acres. As at December 31, 2024, the Corporation held interests in 745 gross (622 net) oil wells and 11 gross (10 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 2024 production in Sparky was approximately 11,610 boe/d (86 percent oil and NGLs).

Sparky is 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 in Sparky is primarily crude oil (86 percent oil and NGLs) ranging from 19° to 28° API.

In 2024, the Corporation drilled 40 gross (40 net) horizontal Sparky oil wells. Of these wells, 35 were on production by year-end 2024 and the remaining wells are expected to come on production in Q1 2025.

Southeast Saskatchewan

As at December 31, 2024, 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, 2024, these operated properties included an average working interest of approximately 86 percent in approximately 59,798 gross (51,378 net) developed acres and an average working interest of approximately 83 percent in 40,633 gross (33,734 net) undeveloped acres. As at December 31, 2024, the Corporation held interests in 362 gross (291 net) oil wells producing in the Midale, Frobisher, Alida, and Ratcliffe formations. The Corporation's production from this property is weighted 71.4 percent to light crude oil (greater than 31.1° API) and 28.6 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 2024 production was approximately 8,560 boe/d (95 percent oil).

In 2024, the Corporation drilled 43 gross (33 net) horizontal, Frobisher and Midale oil wells. Of these wells, 38 were on production by year-end 2024 and the remaining wells are expected to come on production in Q1 2025.

Carbonates

As at December 31, 2024, Carbonates includes the Corporation's Greater Sawn and Nevis 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 81 percent in approximately 131,316 gross (105,744 net) developed acres and an average working interest of approximately 77 percent in approximately 68,394 gross (52,374 net) undeveloped acres. As at December 31, 2024, the Corporation held interests in 433 gross (352 net) oil wells and 15 gross (11 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 2024 production in Carbonates was approximately 2,330 boe/d (92 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.

Minors

As at December 31, 2024, 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 54 percent in approximately 79,771 gross (43,332 net) developed acres and an average working interest of approximately 47 percent in approximately 19,401 gross (9,178 net) undeveloped acres. As at December 31, 2024, the Corporation held interests in 106 gross (84 net) oil wells and 121 gross (39 net) gas wells. This area's fourth quarter 2024 production was approximately 190 boe/d (87 percent oil and NGLs).

Manitoba

As at December 31, 2024, the Corporation’s principal properties in the Manitoba area included Sinclair.

The Manitoba property is primarily located approximately 290 kilometres west of Brandon, Manitoba and east of the Saskatchewan border. As at December 31, 2024, this property included an average working interest of approximately 68 percent in approximately 8,722 gross (5,954 net) developed acres and an average working interest of 68 percent in 900 gross (610 net) undeveloped acres. As at December 31, 2024, the Corporation held interests in 134 gross (73 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 2024 production was approximately 470 boe/d (100 percent oil).

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, 2024. The Reserves Report has a preparation date of February 7, 2025.

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	25,242	8,798	801	20,007	67	21,801	7,468	710	17,709	61
Developed Non-Producing	720	779	50	560	52	627	692	44	474	47
Undeveloped	16,967	6,175	609	11,146	-	14,148	5,308	549	9,770	-
Total Proved	42,929	15,752	1,460	31,713	119	36,576	13,468	1,303	27,953	108
Probable	15,408	5,785	638	17,365	22	12,816	4,789	578	15,659	21
Total Proved plus Probable	58,337	21,537	2,098	49,078	141	49,392	18,257	1,881	43,612	129

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	765,787	857,371	790,752	717,101	654,296
Developed Non-Producing	46,193	36,880	30,444	25,771	22,247
Undeveloped	660,791	483,761	362,337	276,652	214,446
Total Proved	1,472,771	1,378,012	1,183,533	1,019,524	890,989
Probable	978,862	681,244	508,091	397,849	322,898
Total Proved plus Probable	2,451,633	2,059,256	1,691,624	1,417,373	1,213,887

	After Future Income Tax Expenses and Discounted at				
($M)	0%	5%	10%	15%	20%
Proved					
Developed Producing	765,787	857,371	790,752	717,101	654,296
Developed Non-Producing	46,193	36,880	30,444	25,771	22,247
Undeveloped	527,717	384,349	286,144	216,988	166,870
Total Proved	1,339,697	1,278,600	1,107,340	959,860	843,413
Probable	758,570	520,936	385,976	301,521	244,833
Total Proved plus Probable	2,098,267	1,799,536	1,493,316	1,261,381	1,088,246

	Unit Value before Income Tax Discounted at 10%/year ($/boe)
Proved	
Developed Producing	24.01
Developed Non-Producing	21.01
Undeveloped	16.75
Total Proved	21.13
Probable	24.43
Total Proved plus Probable	22.02

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

The following Future Net Revenue table includes abandonment and reclamation costs to abandon and reclaim all of the Corporation's working interest wells, facilities, and pipelines whether or not reserves have been assigned. See "*Additional Information Concerning Abandonment and Reclamation Costs*" for further information.

(Undiscounted) ($M)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Other Costs	Future net revenue before income taxes	Future income taxes	Future net revenue after income taxes
Total Proved	5,641,138	843,396	2,231,234	581,376	512,362	1,472,770	133,074	1,339,696
Total Proved plus Probable	7,860,406	1,213,933	2,947,442	724,921	522,479	2,451,632	353,365	2,098,267

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]	867,160	21.42
Heavy Crude Oil[1]	315,240	20.44
Conventional Natural Gas[2]	1,106	12.06
Coalbed Methane[2]	27	1.37
Proved plus Probable		
Light and Medium Crude Oil[1]	1,252,653	22.78
Heavy Crude Oil[1]	437,534	20.16
Conventional Natural Gas[2]	1,401	12.42
Coalbed Methane[2]	35	1.49

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, 2024 in its evaluation in estimating reserves data using forecast prices and costs. The weighted average historical prices received by the Corporation for 2024 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)**
2024 (Historic)	98.13	83.9	1.39	100.64	48.38	30.40	1.5%	-0.3%	0.73
2025	97.14	83.57	2.29	98.57	50.71	33.47	0.0%	0.0%	0.70
2026	100.69	87.59	3.42	102.07	52.41	34.59	2.0%	2.0%	0.73
2027	97.33	84.67	3.31	98.61	50.67	33.20	2.0%	2.0%	0.75
2028	99.28	86.36	3.35	100.59	51.68	33.86	2.0%	2.0%	0.75
2029	101.27	88.09	3.41	102.60	52.71	34.54	2.0%	2.0%	0.75
2030	103.29	89.85	3.48	104.65	53.77	35.23	2.0%	2.0%	0.75
2031	105.36	91.65	3.55	106.74	54.84	35.93	2.0%	2.0%	0.75
2032	107.46	93.48	3.62	108.88	55.94	36.65	2.0%	2.0%	0.75
2033	109.61	95.35	3.69	111.05	57.06	37.38	2.0%	2.0%	0.75
2034	111.81	97.26	3.77	113.28	58.20	38.13	2.0%	2.0%	0.75
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	2.0%	2.0%	0.75

Reconciliation of Changes in Reserves

The following table sets forth a combined reconciliation of the Corporation's gross reserves as at December 31, 2024, derived from the Reserves Report using forecast prices and cost estimates, reconciled to the gross reserves of the Corporation as at December 31, 2024.

	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, 2023	51,990	19,390	2,108	68,596	-	84,923
Product Type Transfer	-	-	-	-	-	-
Extensions and Improved Recovery[1]	1,869	2,981	39	3,983	-	5,553
Infill Drilling[2]	2,066	267	153	1,243	-	2,693
Technical Revisions[3]	(1,206)	(943)	255	614	387	(1,727)
Acquisitions	-	-	-	-	-	-
Dispositions[4]	(6,011)	(4,330)	(791)	(35,356)	-	(17,024)
Economic Factors[5]	19	(11)	(6)	(592)	(209)	(131)
Production[6]	(5,800)	(1,604)	(299)	(6,776)	(58)	(8,842)
Balance at December 31, 2024	42,927	15,750	1,459	31,712	120	65,445

	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, 2023	19,366	6,842	818	28,406	-	31,759
Product Type Transfer	-	-	-	-	-	-
Extensions and Improved Recovery[1]	721	1,107	(10)	2,132	-	2,174
Infill Drilling[2]	1,195	110	115	793	-	1,552
Technical Revisions[3]	(3,580)	(604)	39	1,771	71	(3,838)
Acquisitions	-	-	-	-	-	-
Dispositions[4]	(2,258)	(1,705)	(307)	(13,579)	-	(6,534)
Economic Factors[5]	(35)	35	(18)	(2,158)	(49)	(385)
Production[6]	-	-	-	-	-	-
Balance at December 31, 2024	15,409	5,785	637	17,365	22	24,728

	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, 2023	71,357	26,234	2,928	97,002	-	116,685
Product Type Transfer	-	-	-	-	-	-
Extensions and Improved Recovery[1]	2,590	4,088	29	6,116	-	7,727
Infill Drilling[2]	3,260	377	268	2,036	-	4,245
Technical Revisions[3]	(4,786)	(1,546)	295	2,385	458	(5,564)
Acquisitions	-	-	-	-	-	-
Dispositions[4]	(8,269)	(6,035)	(1,098)	(48,936)	-	(23,558)
Economic Factors[5]	(16)	24	(23)	(2,751)	(258)	(516)
Production[6]	(5,800)	(1,604)	(299)	(6,776)	(58)	(8,842)
Balance at December 31, 2024	58,336	21,538	2,100	49,076	142	90,177

Notes:

1. Includes the expansion or increased recovery factor for existing reservoirs, as a result of step-out drilling in 2024, booking of new step-out future drilling locations, and enhanced oil recovery associated with new waterflood projects.
2. Positive additions as a result of infill drilling in 2024 and booking of new infill future drilling locations within the Sparky and Southeast Saskatchewan areas.
3. Technical revisions are due to changes in previously booked estimates. In 2024, these revisions were primarily: (1) positive proved developed producing reserves revisions in the Sparky and Southeast Saskatchewan core areas; (2) negative revisions to total proved reserves and total proved and probable reserves primarily due to voluntary removal of 32 gross (28.5 net) undeveloped

drilling locations in the Greater Sawn (Carbonates) and Nevis (Carbonates) areas to better align with reduced activity levels in these areas. The technical revisions specifically for these undeveloped drilling location removals were (2,805) mboe total proved, and (4,333) mboe total proved and probable.

4. Reductions in volume estimates due to selling all or a portion of an interest in oil and gas properties. In 2024, the Shaunavon, Westerose and Valhalla properties were divested in their entirety.
5. The economic factors amount is the change in reserves due to changes in product pricing between the Sproule December 31, 2023 price forecast and the Sproule December 31, 2024 price forecast, which varied for all product types.
6. The Corporation averaged production of 24,158 boe/d in 2024.

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				
2022	2,231	3,479	129	2,102
2023	2,946	788	143	2,141
2024	3,113	1,807	123	2,718

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				
2022	1,871	2,651	133	3,725
2023	1,317	602	71	1,239
2024	1,913	791	103	2,332

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 proved and probable undeveloped reserves within the next five 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)
2025	129,738	137,663
2026	142,856	164,465
2027	149,467	181,087
2028	98,525	164,603
2029	36,356	43,436
Remaining Years	24,434	33,667
Total Undiscounted	581,376	724,921

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 an adverse effect on the Corporation's future cash flow and disclosed reserves.

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, 2024.

	Active							
	Oil		Natural Gas		Coalbed Methane		Water Inj/Disp	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,257	1,039	55	27	7	4	292	204
Saskatchewan	389	322	93	33	-	-	112	100
Manitoba	134	73	-	-	-	-	5	5
BC	-	-	1	1	-	-	-	-
Total	1,780	1,434	149	61	7	4	409	309

	Inactive							
	Oil		Natural Gas		Coalbed Methane		Water Inj/Disp	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	434	294	58	32	-	-	55	41
Saskatchewan	206	90	5	2	-	-	1	1
Manitoba	58	41	-	-	-	-	-	-
BC	-	-	-	-	-	-	-	-
Total	698	425	63	34	-	-	56	42

	Abandoned							
	Oil		Natural Gas		Coalbed Methane		Water Inj/Disp	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,471	1,257	328	237	1	1	245	209
Saskatchewan	147	100	620	599	-	-	20	11
Manitoba	11	11	-	-	-	-	-	-
BC	1	-	-	-	-	-	-	-
Total	1,630	1,368	948	836	1	1	265	220

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2024, 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	131,360	108,231	486
Saskatchewan	53,970	42,040	267
Manitoba	900	610	-
BC	-	-	-
Total	186,230	150,881	753

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. There are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data - Significant Factors or Uncertainties Affecting Reserves Data*" –" and "*Risk Factors*".

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation will incur abandonment and reclamation costs for wells, facilities, pipelines and surface leases, in connection with its operations.

The Corporation estimates well, facility and pipeline abandonment and reclamation costs on an individual well, facility and pipeline segment level. Each well, facility and pipeline segment is assigned an average cost for abandonment and reclamation over its useful life. Timing of expenditures take into account the geographical location, seasonal access, and opportunities for multi-location abandonment and reclamation programs to reduce costs. Such costs are included in the Reserves Report on a net working interest basis as deductions in arriving at future net revenue over the subsequent 50 years from the Reserves Report date.

The expected total abandonment and reclamation costs included for Surge's 4,734 net wells as at December 31, 2024, in addition to net facilities and net pipelines under the proved plus probable reserves category is $443.8 million undiscounted and uninflated ($107.0 million inflated at two percent and discounted at 10 percent), of which a total of $37.3 million is estimated to be incurred in 2025, 2026 and 2027. Costs to abandon and reclaim all company working interest wells, pipelines, and facilities are included whether or not reserves have been assigned from the estimates of the future net revenue disclosed in this Annual Information Form.

Facilities and pipeline abandonment and reclamation costs are generally scheduled to begin at the end of the reserve life of the associated reserves in the area. No estimate of salvage value is netted against the estimated cost. 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 and are subject to pending changes in applicable regulations regarding the abandonment and reclamation ongoing environmental obligations. All costs to abandon and reclaim the Corporation's wells, facilities, and pipelines 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, 2024, see the Corporation's audited annual financial statements for the year ended December 31, 2024, which have been filed on SEDAR+ and may be viewed under the Corporation's profile at www.sedarplus.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 2027.

Costs Incurred

The following table summarizes capital expenditures incurred by the Corporation during the year ended December 31, 2024.

	Property Acquisition Costs				
	Proved Properties	Unproved Properties	Property Dispositions	Exploration Costs	Development Costs
Total ($M)	-	-	(45,924)	-	195,013

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, 2024.

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	63.00	53.05
Heavy Crude Oil	-	-	20.00	20.00
Conventional Natural Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
Total	-	-	83.00	73.05

Planned Capital Expenditures

The Corporation has announced a planned capital expenditure budget of approximately $170 million for 2025.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Reserves Report for 2024 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	2,007	-	876	-	32	2,185	9%
Sparky	5,718	5,453	10,006	-	159	12,996	57%
SE Saskatchewan	6,174	-	2,611	-	424	7,033	31%
Manitoba	481	-	-	-	-	481	2%
Minors	110	12	125	-	7	150	1%
Total Proved	14,490	5,465	13,618	-	622	22,845	100%
Proved Plus Probable							
Carbonates	2,037	-	888	-	33	2,218	9%
Sparky	6,084	5,904	10,664	-	167	13,933	56%
SE Saskatchewan	6,964	-	3,005	-	491	7,956	32%
Manitoba	528	-	-	-	-	528	2%
Minors	113	12	129	-	7	154	1%
Total Proved Plus Probable	15,726	5,916	14,686	-	698	24,789	100%

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2024, 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, 2024	Jun 30, 2024	Sep 30, 2024	Dec 31, 2024
Conventional Natural Gas (Mcf/d)	20,387	18,641	17,991	17,054
Light and Medium Crude Oil (bbls/d)	20,620	19,628	19,988	20,675
NGL (bbls/d)	860	856	779	777
Coalbed Methane (Mcf/d)	152	164	177	145
Total (boe/d)	24,903	23,618	23,795	23,319

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

	Three Months Ended			
($ per Bbl)	Mar 31, 2024	Jun 30, 2024	Sep 30, 2024	Dec 31, 2024
Prices Received	69.48	80.42	74.05	72.78
Royalties Paid	(13.29)	(12.89)	(14.92)	(13.33)
Production Costs	(21.66)	(20.18)	(18.72)	(19.06)
Transportation Costs	(1.18)	(1.22)	(1.39)	(1.39)
Operating Netback[(1)]	33.35	46.13	39.02	39.00

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, 2024	Jun 30, 2024	Sep 30, 2024	Dec 31, 2024
Prices Received	1.88	0.92	0.24	0.88
Royalties Received	(0.06)	0.53	0.25	0.35
Production Costs	(0.89)	(0.77)	(0.54)	(0.34)
Transportation Costs	-	-	-	-
Operating Netback	0.93	0.68	(0.05)	0.89

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

	Three Months Ended			
($ per boe)	Mar 31, 2024	Jun 30, 2024	Sep 30, 2024	Dec 31, 2024
Prices Received	69.79	80.57	74.09	72.93
Royalties Paid	(13.30)	(12.80)	(14.88)	(13.27)
Production Costs	(21.81)	(20.31)	(18.81)	(19.12)
Transportation Costs	(1.18)	(1.22)	(1.39)	(1.39)
Operating Netback[(1)]	33.50	46.24	39.01	39.15

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, 2024.

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	2,211	1,316	53	-	2,483	10%
Valhalla[(1)]	547	4,743	133	-	1,470	6%
Sparky	9,436	9,575	196	-	11,228	47%
Shaunavon[(2)]	305	281	5	-	357	1%
Minors	144	(6)	11	159	181	1%
SE Saskatchewan	7,141	2,599	416	-	7,990	33%
Manitoba	444	5	4	-	449	2%
Total	20,228	18,513	818	159	24,158	100%

Notes:

1. The Corporation completed the sale of its Valhalla properties in December 2024. See "Development of the Business - Three Year History - Year Ended December 31, 2024".
2. The Corporation completed the sale of its Shaunavon properties in May 2024. See "Development of the Business - Three Year History - Year Ended December 31, 2024".

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 conditions attributed to the Common Shares and preferred shares.

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.

Credit Facility

The Credit Facility is governed by the Credit Agreement and is comprised of a $200 million revolving credit facility and a $50 million operating credit facility.

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

A review and redetermination of the Corporation's borrowing base is scheduled to occur semi-annually on or before May 31 and November 30 of each year. The Credit Facility is available on a revolving basis until May 29, 2025. On May 29, 2025, at the Corporation's discretion, the Credit Facility is available on a non-revolving basis for a one-year period, at the end of which time the Credit Facility would be due and payable. Alternatively, the Credit Facility may be extended for a further 364-day period at the request of the Corporation and subject to the approval of the syndicate of lenders. Interest rates vary depending on Senior Debt to EBITDA Ratio (as defined in the Credit Agreement). As at December 31, 2024, the Corporation had an effective interest rate of prime plus 1.75 percent on the Credit Facility (December 31, 2023 – prime plus 1.75 percent).

The facilities are secured by a general assignment of book debts, debentures of $0.8 billion with a floating charge over all assets of the Corporation with a negative pledge and undertaking to provide fixed charges on the major producing oil and natural gas properties at the request of the bank.

Debentures

The Debentures were issued under and pursuant to the provisions of the Debenture Indenture between Computershare Trust Company of Canada, as trustee, and the Corporation.

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 Debenture Indenture which may be viewed under Surge's profile on SEDAR+ at www.sedarplus.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 December 31, 2028 (the "**Debenture Maturity Date**") and will accrue interest at the rate of 8.50 percent per annum payable semi-annually in arrears on December 31 and June 30 of each year (each a "**Debenture Interest Payment Date**"), commencing on June 30, 2024 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 (i) the business day immediately preceding the Debenture Maturity Date; or (ii) if the Debentures are called for redemption, on the business day immediately preceding the date (the "**Debenture Redemption Date**") specified by the Corporation for redemption of the Debentures, in each case, at a conversion price of $13.25 (the "**Conversion Price**") per Common Share, representing a conversion rate of approximately 75.4717 Common Shares per $1,000 principal amount of offered Debentures, subject to adjustment in accordance with the Debenture Indenture. 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 Debenture Indenture).

The Debentures will not be redeemable by the Corporation prior to December 31, 2026, except in certain limited circumstances following a change of control. On, and after, December 31, 2026 and prior to December 31, 2027, the Debentures may be redeemed by the Corporation, subject to certain restrictions, 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 the principal amount thereof plus accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption, provided that the Current Market Price on the date on which notice of redemption is given is not less than 125 percent of the Conversion Price. On or after December 31, 2027 and prior to the Debenture Maturity Date, the Debentures may be redeemed by the Corporation, subject to certain restrictions, 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 the principal amount thereof plus accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption.

On the Debenture Redemption Date or the Debenture Maturity Date, as applicable, subject to required regulatory approvals and provided that no event of default (as provided in the Debenture Indenture) has occurred and is continuing, the Corporation may, at its option, on not more than 60 days', and not less than 30 days', prior notice, elect to satisfy its obligation to repay, in whole or in part, the principal amount of the Debentures which are to be redeemed or which have matured by issuing and delivering freely tradeable Common Shares to the holders of the Debentures. Payment for which the Corporation elects to repay in Common Shares would be satisfied by delivering that number of Common Shares obtained by dividing the principal amount of the Debentures by 95 percent of the Current Market Price of the Common Shares on the Debenture Redemption Date or Debenture Maturity Date, as applicable. Any accrued and unpaid interest will be paid in cash.

The Debentures are listed and posted for trading on the TSX under the symbol "SGY.DB.B".

Senior Notes

The Senior Notes were issued under and pursuant to the provisions of the Senior Notes Indenture between Odyssey Trust Company of Canada, as trustee, and the Corporation.

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

The Senior Notes are direct, senior, unsecured obligations of the Corporation, ranking senior to any future subordinated indebtedness of the Corporation and ranking equally with any existing and future senior indebtedness of the Corporation.

The Senior Notes will mature and be repayable on September 5, 2029, and will accrue interest at the rate of 8.50 percent per annum, calculated and payable semi-annually in arrears on March 5 and September 5 of each year (each a "**Senior Notes Interest Payment Date**"), commencing on March 5, 2025. Interest on the Senior Notes will be payable in lawful money of Canada.

The Senior Notes are redeemable by the Corporation prior to September 5, 2026, in certain limited circumstances, including following a change of control (as more fully described in the Senior Notes Indenture).

Prior to September 5, 2026, the Corporation may, on any one or more occasions, redeem up to 40 percent of the aggregate principal amount of issued Senior Notes, subject to certain restrictions, on not less than 10 days', and not more than 60 days' prior notice, at a redemption price equal to 108.500 percent of the principal amount of the Senior Notes redeemed, plus accrued and unpaid interest, if any, up to but excluding the date of redemption (subject to the right of holders of Senior Notes on the relevant record date to receive interest on the relevant Senior Notes Interest Payment Date), with the net cash proceeds of an equity offering by the Corporation (as more fully described in the Senior Notes Indenture), provided that (i) at least 60 percent of the aggregate principal amount of Senior Notes originally issued under the Senior Notes Indenture (excluding Senior Notes held by the Corporation and its subsidiaries) remain outstanding immediately after the occurrence of such redemption; and (ii) the redemption occurs within 180 days of the date of the closing of such equity offering.

Prior to September 5, 2026, the Corporation may on any one or more occasions redeem all or any part of the Senior Notes, subject to certain restrictions, on not less than 10 days', and not more than 60 days' prior notice, at a redemption price equal to 100 percent of the aggregate principal amount of the Senior Notes redeemed plus the Applicable Premium (as defined in the Senior Notes Indenture) and accrued and unpaid interest, if any, up to but excluding the date of redemption (subject to the right of holders of Senior Notes on the relevant record date to receive interest due on the relevant Senior Notes Interest Payment Date).

On, and after, September 5, 2026 and prior to September 5, 2027, the Corporation may on any one or more occasions redeem all or any part of the Senior Notes, subject to certain restrictions, on not less than 10 days', and not more than 60 days' prior notice, at the redemption price equal to 104.25 percent of the aggregate principal amount of the Senior Notes redeemed, plus accrued and unpaid interest, if any, up to but excluding the date of redemption (subject to the right of holders of Senior Notes on the relevant record date to receive interest on the relevant Senior Notes Interest Payment Date). On, and after, September 5, 2027 and prior to September 5, 2028, the Corporation may on any one or more occasions redeem all or any part of the Senior Notes, subject to certain restrictions, on not less than 10 days', and not more than 60 days' prior notice, at the redemption price equal to 102.125 percent of the aggregate principal amount of the Senior Notes redeemed, plus accrued and unpaid interest, if any, up to but excluding the date of redemption (subject to the right of holders of Senior Notes on the relevant record date to receive interest on the relevant Senior Notes Interest Payment Date).

On, and after, September 5, 2028, the Corporation may on any one or more occasions redeem all or any part of the Senior Notes, subject to certain restrictions, on not less than 10 days', and not more than 60 days' prior notice, at the redemption price equal to 100 percent of the aggregate principal amount of the Senior Notes redeemed, plus accrued and unpaid interest, if any, up to but excluding the date of redemption (subject to the right of holders of Senior Notes on the relevant record date to receive interest on the relevant Senior Notes Interest Payment Date).

Ratings

The following table outlines the current credit ratings for the Corporation, and its Senior Notes as of the date hereof:

Category	S&P
Corporate Rating	B
Senior Notes	B+ (recovery rating of 2)

A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments.

An S&P Global Ratings ("**S&P**") issuer credit rating is a forward-looking opinion about an issuer's overall creditworthiness. Such credit rating focuses on the issuer's capacity and willingness to meet its financial commitments as they become due. An S&P issue credit rating is a forward-looking opinion about the creditworthiness of an issuer with respect to a specific financial obligation, a specific class of financial obligations, or a specific financial program. It takes into consideration the creditworthiness of guarantors, insurers, or other forms of credit enhancement on the obligation and takes into account the currency in which the obligation is denominated. Such rating reflects S&P's view of the issuer's capacity and willingness to meet its financial commitments as they come due, and this rating may assess terms, such as collateral security and subordination, which could affect ultimate payment in the event of default. S&P's credit ratings are on a rating scale that ranges from "AAA" to "D", which represents the range from highest to lowest quality.

Recovery ratings focus solely on expected recovery in the event of a payment default of a specific issue. Such rating is not linked to, or limited by, the issuer credit rating or any other rating, and provides a specific rating about the expected recovery. S&P's recovery ratings are on a rating scale that ranges from "1+" to "6", which represents the range from highest to lowest expectation of recovery in the event of default.

An issuer credit rating of "B" is within the sixth highest of 9 categories and indicates that the obligator is more vulnerable than the obligators rated "BB", but the Corporation currently has the capacity to meet its financial commitments. However, adverse business, financial, or economic conditions will likely impair the Corporation's capacity or willingness to meet its financial commitments. According to the S&P rating system, obligors rated "BB", "B", "CCC", and "CC", are regarded as having significant speculative characteristics, indicating that while such obligors will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions. "BB" indicates the least degree of speculation and "CC" indicates the highest. The ratings from "AA" to "CCC" may be modified by the addition of a (+) or a (-) sign to show relative standing within the major rating categories.

An issue credit rating of "B+" is within the sixth highest of 10 categories and indicates that the obligation is more vulnerable to nonpayment than obligations rated "BB", but the Corporation currently has the capacity to meet its financial commitments on the obligation. However, adverse business, financial, or economic conditions will likely impair the Corporation's capacity or willingness to meet its financial commitments on the obligation. According to the S&P rating system, obligations rated "BB", "B", "CCC", "CC", and "C", are regarded as having significant speculative characteristics, indicating that while such obligations will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions. "BB" indicates the least degree of speculation and "C" indicates the highest. The ratings from "AA" to "CCC" may be modified by the addition of a (+) or a (-) sign to show relative standing within the major rating categories.

A recovery rating of 2 is within the third highest of 7 categories and denotes an expectation of substantial recovery in the event of default.

The credit ratings accorded by S&P are not recommendations to purchase, hold or sell securities or make any investment decisions, and may be subject to revision or withdrawal at any time by the credit rating organization. Such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future, if in its judgment, circumstances so warrant. The Corporation has paid fees to S&P in 2024 in respect of the Corporation and the Senior Notes.

DIVIDEND POLICY

The Credit Facility contains 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	**2024**	**2023**	**2022**
January	0.040	0.040	-
February	0.040	0.040	-
March	0.040	0.040	-
April	0.040	0.040	-
May	0.040	0.040	-
June	0.040	0.040	0.035
July	0.043	0.040	0.035
August	0.043333	0.040	0.035
September	0.043333	0.040	0.035
October	0.043333	0.040	0.035
November	0.043333	0.040	0.035
December	0.043333	0.040	0.035
Total	**0.499665**	**0.48**	**0.245**

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 Facility, 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 "*Risk Factors*".

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, 2024.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
January	6.72	6.06	8,336,655
February	6.97	5.89	6,973,267
March	7.77	6.34	10,963,691
April	8.16	7.45	9,968,826
May	7.45	6.80	12,741,856
June	7.29	6.65	6,624,837
July	7.36	6.71	10,020,987
August	7.16	6.17	9,274,762
September	6.44	5.51	7,994,896
October	6.54	5.83	12,114,430
November	6.07	5.32	15,335,926
December	5.83	4.94	11,685,636

The Debentures are listed and posted for trading on the TSX under the trading symbol "SGY.DB.B". 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, 2024.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
January	102.00	101.00	937,000
February	102.00	101.00	306,000
March	102.50	101.10	228,000
April	104.50	101.00	323,000
May	103.75	101.00	123,000
June	102.25	101.00	1,046,000
July	103.50	102.00	130,000
August	103.60	101.00	249,000
September	102.10	101.50	160,000
October	103.80	102.10	206,000
November	104.00	102.01	259,000
December	102.55	101.01	106,000

DIRECTORS AND OFFICERS

The name, province of residence, principal occupation for the prior five years and position with the Corporation of each of the directors and executive officers of the Corporation as of the date hereof 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 from January 1, 2020 to August 31, 2023. 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	Chair of the Compensation, Nominating and Corporate Governance Committee for the Corporation. Director, Calgary Academy and Headwater Learning Group since June 2018. Prior thereto, Director, SECURE Energy Services from April 2020 to July 2021. A seasoned industry leader with nearly 30 years of experience in Midstream infrastructure development, her experience reflects focus is commercial negotiations, governance, environmental, health and safety, strategy and risk management. She held increasingly responsible roles with Spectra Energy Corporation, retiring as Vice President, Field Services and Strategy in 2017. 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(3)(4) Alberta, Canada	Director since June 5, 2014	Chair of the Environment and Safety Committee and a member of the Reserves Committee for the Corporation. Managing Director and Investment Committee member of Carbon Infrastructure Partners Inc. (formerly JOG Capital Inc. ("**JOG Capital**")) since May 2008. Mr. Gilbert has also been an independent businessman and investor, and has served as a director for a number of public and private entities, since 2005. 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.

Name and Residence	Position	Principal Occupation During Previous Five Years
		(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)(2)(3) Alberta, Canada	Director since May 14, 2019	Ms. Gramatke is a Chartered Professional 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)(2)(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 Reserves 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	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. 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

Name and Residence	Position	Principal Occupation During Previous Five Years
		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, Exploration	Senior Vice President, Exploration of the Corporation since January 2024. Prior thereto, Mr. Christie held the position of Senior Vice President, Geosciences of the Corporation from 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.

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 and Safety Committee of the Board.

As at March 5, 2025, to the knowledge of the Corporation, the directors and executive officers of the Corporation, as a group, beneficially owned, controlled or directed, directly or indirectly, 3,227,069 Common Shares, representing approximately 3.2 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 (the "**AER**"). 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.

Mr. O'Neil was a director of Cequence Energy Ltd. ("**Cequence**") from March 2019 to May 2020. On May 29, 2020, Cequence announced that it had commenced a strategic process to identify and pursue potential strategic options and alternatives to maximize the value for its stakeholders, to be carried out under the CCAA and that it had on obtained an initial order (the "**Initial Order**") from the Court commencing proceedings under the CCAA on that same date. Mr. O'Neil tendered his resignation as a director of Cequence prior to Cequence obtaining the Initial Order. Based on publicly available information, on September 28, 2020, Cequence announced that the implementation of a plan of compromise and arrangement under the CCAA had been sanctioned on September 17, 2020 by order of the Court.

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, the Advisory Board of Rohit, 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 was a member of the board of the Calgary Health Foundation from February 2020 to April 2023 and was a member of the board of the Heritage Park Foundation from June 2014 to June 2020. Ms. Maher was a trustee for the Cidel Donor Advised Fund from June 2014 and will be retiring in July 2025. 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.
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.

Name	Independent	Financially Literate	Relevant Education and Experience
			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 provides that 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 has delegated to the Chair of the Audit Committee the authority to pre-approve non-audit services, provided that the Chair reports to the Audit Committee at the next scheduled meeting and such pre-approval and the Chair comply with such other procedures as may be established by the Audit Committee from time to time. 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(3)
2024	$473,090	$nil	$26,780	$149,800
2023	$428,000	$nil	$91,325	$74,900

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. Tax fees consist of fees for tax compliance, tax advice and tax planning.
3. All other fees consist of fees for services related to prospectus filings.

INDUSTRY CONDITIONS

Companies carrying on business in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government 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 oil and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation may be enacted, whether existing legislation will be amended or repealed, including as a result of any shifts or changes in governmental policy due to new or existing administrations in the jurisdictions in which the Corporation conducts its business. While such laws and 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. The industry conditions set out below are not an exhaustive summary of all conditions, policies, projects, legislation, regulations and other matters which may have an impact on the Corporation’s business, financial condition, results of operations and prospects, the business of third parties with whom the Corporation conducts business and the crude oil and natural gas industry generally.

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.

Since June of 2023, OPEC+ producers have to target lower oil supply and voluntary production cuts in order to stabilize the price of oil. The voluntary production cuts were extended in December 2024, with a plan to gradually phase out these adjustments by the latter half of 2026.

During 2024, the price of crude oil has declined and is expected to drop further by the end of 2025.
While the trajectory of oil prices continues to be subject to uncertainty and volatility, factors such as transportation disruptions, supply constraints and the conflicts in Ukraine and the Middle East continue to be unpredictable and may have an ongoing impact on oil demand and prices. See “*Risk Factors – Exposure to Widespread Pandemic and Risks Related Thereto*”, “Risk Factors – Political Uncertainty” and “*Risk Factors – Commodity Prices, Markets and Marketing*”.

According to statistics released by the Canadian Energy Regulator (the “**CER**”), as of the end of July 2024, the year-to-date crude oil production in Canada reached the highest on record, averaging 5.0 million barrels per day, up from 4.8 million barrels on average at the same point in the year in 2023. The International Energy Agency’s January 2025 Oil Market Report forecasts that global oil supply will rise in 2025.

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.

The production of natural gas in 2024 remained relatively unchanged from 2023, a contrast to the production growth in the previous three years, as low natural gas prices curtailed production in some regions. As of October 2024, the International Energy Agency forecasted that world natural gas demand will increase in 2025 by 100 Bcm, or 2.3%, primarily driven by growth in Asian.

Despite low prices of natural gas in 2024, it is expected that Western Canadian producers will be able to ramp up production ahead of LNG Canada's Kitimat LNG facility coming online, which will be Canada's first large-scale liquified natural gas export facility, expected to start operations in mid-2025.

Natural Gas Liquids

The pricing of condensates and other NGLs, including ethane, butane, propane and pentane 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

The CER is responsible for governing the export of crude oil, natural gas and NGL from Canada. The CER's governing legislation is the *Canadian Energy Regulator Act* (the "**CERA**") and the *Impact Assessment Act* (the "**IAA**").

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*). 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 do not exceed 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 they meet the reporting obligations set out in the Part IV Regulation and that export contracts continue to meet certain criteria prescribed by the CER and the Canadian 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. Growing production and a lack of new and expanded pipeline and rail infrastructure capacity caused producers in Western Canada to experience low commodity pricing relative to other markets in the last several years. However, operationalization of LNG Canada's Kitimat facility is expected to occur in mid-2025, which could boost exports of natural gas from Western Canada and the commercial operation of the Trans Mountain Pipeline expansion has increased capacity for the transportation of crude oil to tidewater on the west coast of British Columbia.

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 prices received by producers.

Under the *Constitution Act, 1867*, interprovincial and international pipelines fall within the federal government's jurisdiction. Under the CERA, new interprovincial and international pipelines 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. Consequently, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments, public interest groups and legal opposition. These issues often relate to Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes and assessments. 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. Further, with the change of United States administration in 2025, there is additional unpredictability with the actions the Trump administration may take throughout its term.

In the face of such regulatory uncertainty, the Canadian oil 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

Line 5 Tunnel Replacement Project

In December 2023, Michigan Regulators approved Enbridge's Line 5 Tunnel Replacement Project ("**Line 5**"), marking the end of a more than three-year long evaluation process. Line 5 is seen as crucial infrastructure supplying Michigan, Ontario and Québec. This approval begins the process of replacing seven kilometres of the current pipeline with a new underwater tunnel in the Straights of Mackinac. The pipeline will be housed within a concrete tunnel beneath the lakebed. The tunnel project must first be approved by the U.S. Army Corps of Engineers at the United States federal level before construction can commence. The U.S. Army Corps of Engineers has initiated an environmental impact assessment, which is expected to be completed by 2026.

Enbridge has also proposed a 41-mile reroute for Line 5 around the Bad River Band of Lake Superior Chippewa's reservation (the "**Reroute**"). In November 2024, the Wisconsin Department of Natural Resources issued construction permits for the Reroute, a condition of which is that the Reroute must be completed by November 14, 2027.

Trans Mountain Pipeline

Following years of legal and regulatory proceedings, construction challenges and delays, the Trans Mountain Pipeline expansion commenced commercial operations on May 1, 2024, tripling the capacity of the pipeline and adding an additional 590,000 barrels per day of shipping capability. This accounts for 17 percent of the total pipeline export capacity available to Canadian crude oil shippers, according to the CER.

Keystone XL Pipeline

While construction on TC Energy Corporation's ("**TC Energy**") Keystone XL Pipeline (the "**Keystone XL Pipeline**") started in April 2020, the Keystone XL Pipeline remained subject to legal and regulatory barriers in the United States. In 2021 the Biden Administration announced its decision to revoke the federal permit granted by the previous administration for the Keystone XL Pipeline. 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.

Since the United States presidential election in the fall of 2024, speculation has arisen that the Trump administration may revive construction of the Keystone XL Pipeline. However, uncertainty remains as to the advancement of pipeline projects between Canada and the United States amid political uncertainty and as key easements have been returned to landowners in relation to the project.

The Prince Rupert Gas Transmission Line

In March 2024, the Nisga'a Nation and Western LNG acquired the Prince Rupert Gas Transmission Line (the "**PRGT Project**"), a ready-to-construct pipeline that is intended to supply the proposed Ksi Lisims LNG Project.

The PRGT Project received its Environmental Assessment Certificate (the "**BC EAC**") from the British Columbia Environmental Assessment Office (the "**BC EAO**") on November 25, 2014. On April 25, 2019, the PRGT Project was granted a one-time, five-year extension. This extension moved the deadline for the start of construction to November 25, 2024, as required by the BC EAC. Approaching the deadline, on November 19, 2024, the PRGT Project submitted an application to the BC EAO seeking a determination that the project had substantially started as mandated by the BC EAC. The project is currently pending a determination from the BC EAO on whether it has substantially started. Additionally, the project is awaiting decisions by the BC EAO on two amendment applications related to route and termination point changes

<u>*Marine Tankers*</u>

The *Oil Tanker Moratorium Act* (Canada), 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*".

<u>*Crude Oil and Bitumen by Rail*</u>

The federal government has ordered that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. As a result, trains meeting this threshold are required to adhere to the reduced speed limits 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.

<u>*Natural Gas and LNG*</u>

Natural gas prices in Alberta and British Columbia have been constrained in recent years due to increasing North American supply, limited access to markets, and limited storage capacity. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access broader 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 led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations.

In August 2023, TC Energy sought regulatory approval for a potential minority interest sale of its NOVA Gas Transmission Ltd. ("**NGTL**") pipeline network (the "**NGTL System**"). In July 2024, TC Energy announced that it had signed a deal with a consortium of Indigenous communities to sell a minority interest in the NGTL System for $1 billion, backed by the Alberta Indigenous Opportunities Corporation. However, in September 2024, TC Energy announced that the deal had been delayed due to a transaction structuring issue within the NGTL partnership.

On January 26, 2024, the Biden administration announced a temporary pause on pending decisions on exports of LNG to non-free trade agreement countries until the US Department of Energy can update the underlying analysis for authorizations. In January 2025 the Trump administration ended the pause, resuming processing export permit applications for new LNG projects. It is uncertain at this time the effect this may have on Canadian LNG export projects, including demand for the export of LNG.

Development of both provincial and federal net zero frameworks may also impose restrictions on natural gas and LNG projects in Canada, particularly as provincial and federal governments work to achieve emissions reduction targets.

<u>*Specific Pipeline and Proposed LNG Export Terminal Updates*</u>

Coastal GasLink Pipeline

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, opposition from environmental and Indigenous communities and changing market conditions have resulted in the cancellation or delay of many of these projects. The Coastal GasLink pipeline (the "**CGL Pipeline**") 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 CGL Pipeline. In November 2024, the CGL Pipeline commenced commercial service. A group of 17 First Nations that are situated along the pipeline route have signed an agreement for the option to buy a 10% stake in the project.

Woodfibre LNG Project

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project (the "**Woodfibre LNG Project**"). The project was proposed as a joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited, a subsidiary of Woodside Petroleum Ltd. On July 31, 2023, the project officially commenced construction on the first of the proposed eighteen modules for the project. As of the date of this AIF, construction for the Woodfibre LNG Project remains underway and has not experienced any major disruptions. The Woodfibre LNG Project is expected to be substantially completed in the third quarter of 2027.

The Énergie Saguenay Project

GNL Québec Inc., the proponent of the Énergie Saguenay project (the "**Énergie Saguenay Project**"), was working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on the Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project was slated for completion in 2026; however, on February 7, 2022, the Impact Assessment Agency of Canada (the "**IA Agency**") concluded that the project was likely to cause an adverse environmental impact. Although the federal government has rejected the initial plan, GNL Quebec Inc. is not prevented from submitting a new or revised project proposal for authorization. As of the date of this AIF, no revised proposal has been submitted.

Cedar LNG Project

Cedar LNG Export Development Ltd.'s Cedar LNG project (the "**Cedar LNG Project**") near Kitimat, British Columbia is set to be the first Indigenous majority owned LNG project in the world. The BC EAO completed its assessment of the application for an environmental assessment certificate in November 2022 on behalf of the IA Agency. On March 15, 2023, both the provincial and federal government provided a decision statement indicating the project may proceed.

On January 4, 2024, the Haisla Nation and Pembina Pipeline Corporation announced that Samsung Heavy Industries (SHI) and Black & Veatch were selected for engineering, procurement and construction design, and fabrication and delivery of the floating LNG production units. On June 25, 2024, a positive final investment decision was declared for the Cedar LNG Project and construction commenced in early July 2024. Peak construction is anticipated in 2026, and it is anticipated that the Cedar LNG Project will be in service in late 2028.

Ksi Lisims LNG Project

The Nisga'a Nation, Rockies LNG Limited Partnership and Western LNG are proposing to jointly build the Ksi Lisims LNG natural gas liquefaction and marine terminal project (the "**Ksi Lisims LNG Project**"). The Ksi Lisims LNG Project is a proposed LNG facility to be located on a site owned by the Nisga'a Nation in British Columbia. The Ksi Lisims LNG Project is currently undergoing a joint environmental assessment by the BC EAO and the IA Agency following its application for an environmental certificate in October 2023. The Ksi Lisims LNG Project is currently in the Effects Assessment and Recommendation stage and took public comment on its draft assessment report between November 12 and December 12, 2024. In October 2024, Gitanyow Huwlip Hereditary Chiefs initiated legal proceedings against the Ksi Lisims LNG Project raising concerns over the potential threat to salmon populations, climate change impacts, and inadequate consultation with the Gitanyow Huwilp. These proceedings are ongoing and could lead to delays and further conditions being imposed on the Ksi Lisims LNG Project.

Construction is anticipated to begin in 2025 with the site operational in 2029.

The United States Mexico Canada Agreement and Other Trade Agreements

NAFTA/USMCA

The North American Free Trade Agreement that previously existed among the governments of Canada, the United States and Mexico was replaced in 2020 by a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**") and sometimes referred to as the Canada United States Mexico Agreement.

Article 34.7 of the USMCA requires the three signatory countries to hold a joint review of the agreement six years after its entry into force, which is July 1, 2026. The exact procedure for conducting the review remains undecided and there is no precedent to follow. As the review date is approaching, the three signatory countries have begun internal reviews and consultations. As 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, any changes to the USMCA could have an impact on Western Canada's oil and natural gas industry at large, including the Corporation's business.

On February 1, 2025, U.S. President Trump signed an executive order (the "**Executive Order**") imposing a 25% tariff on all goods originating in Canada and imported into the United States and a 10% tariff on "energy and energy resources" from Canada, effective on February 4, 2025. The Executive Order also states that if Canada introduces retaliatory measures, such as through the imposition of import duties on United States exports to Canada (or other similar measures), the United States tariffs may be increased or expanded. In response, the Government of Canada imposed 25% tariffs on $155 billion in goods imported from the United States, coming into effect in two phases starting on February 4, 2025. Provincial governments across Canada have also responded to the United States tariffs, in some cases introducing their own retaliatory measures. On February 3, 2025, Canada and the United States agreed to delay the imposition of their respective tariffs on imported goods for 30 days. Effective March 4, 2025, the tariffs imposed by both the United States and Canada took effect.

Discussions may continue regarding a potential economic arrangement between the two countries, however, there remains significant uncertainty over the scope, impact, and duration of the imposed tariffs, surtaxes, or other restrictive trade measures or countermeasures which may be enforced, including any expansion or further tariffs which may be imposed. Potential further measures could include, among others, increased tariffs on Canadian energy exports, restrictions on cross-border supply chains, or additional regulatory barriers to trade. The full effects of the imposed tariffs on the oil and natural gas industry and specifically Surge's business are unknown at this time. See "*Risk Factors – Emerging Risks*" and "*Risk Factors – Commodity Prices, Markets and Marketing*".

Other Trade Agreements

The Canadian Free Trade Agreement (the "**CFTA**") is an intergovernmental trade agreement signed by Canadian ministers representing the federal government and all 13 provinces and territories with the objective of reducing and eliminating, to the extent possible, barriers to the free movement of persons, goods, services and investments with Canada and to establish an open, efficient and stable domestic market.

Canada has also pursued other international free trade agreements with 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 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 it has not received full ratification by national legislatures in the European Union.

Following the United Kingdom's departure from the European Union ("**Brexit**") on January 31, 2020, the United Kingdom and Canada agreed to an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity Agreement (the "**CUKTCA**"). The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship. On January 25, 2024, the United Kingdom formally notified Canada that it had paused negotiations for a new free trade agreement, though the CUKTCA remains in force.

Canada and 10 other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership (the "**CPTPP**") which allows for preferential market access among its parties. The CPTPP is in force among: Canada, Australia, Japan, Mexico, New Zealand, Singapore, Vietnam, Peru, Malaysia, Chile and Brunei Durussalam. 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 how the CFTA, CETA, CPTPP, CUKTCA or any other trade agreements may impact the oil and natural gas industry in Canada in any given year, the completion of the Trans Mountain Pipeline expansion and anticipated completion of LNG Canada's Kitimat facility may facilitate shipping access to these markets for Canadian producers. However, even with these projects, the infrastructure for the offshore export of crude oil and natural gas remains constrained and 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 located in that province). Provincial governments grant rights to explore for, and produce, crude oil and/or 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 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.

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 mineral 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. Crude oil and natural gas activities conducted on reserve lands are governed by the *Indian Oil and Gas Act* (Canada) and the *Indian Oil and Gas Regulations*, which were each subject to modernizing amendments that went into effect in 2019.

On September 26, 2023, the Supreme Court of British Columbia ruled in *Gitxaala v British Columbia (Chief Gold Commissioner)* that British Columbia must consult Indigenous communities before registering mineral claims on their traditional territories under the *Mineral Tenure Act* (British Columbia) (the “**MTA**”). The

Supreme Court of British Columbia deferred its decision for 18 months, giving time for the Government of British Columbia to create a consultation-based claims system or for government amendments to the MTA. In March 2024, British Columbia issued four Orders in Council pausing all mining in Gitxaala and Ehattesaht Nations territories as interim measures until the MTA has been amended. The British Columbia Ministry of Mining and Critical Mines is currently working with Indigenous communities, the mineral exploration sector, and interested groups on a Mineral Claim Consultation Framework, which will require the Province of British Columbia to consult with Indigenous communities before new claims are registered. This framework must be in place by March 26, 2025 to meet the court deadline. It is not yet certain whether these decisions will impact the mineral rights regimes in other provinces.

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

<u>General</u>

Each province has legislation and regulations that govern royalties, production rates and other matters relevant to the industry. 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 oil and natural gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the oil and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, 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.

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 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. Under the *Mines and Minerals Act* (Alberta), producers have only three years to submit any amendments to their royalty calculations before they become statute-barred.

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 mineral rights 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.

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. On April 1, 2021, 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**") on associated natural gas produced from wells other than natural gas wells, including natural gas produced from oil wells. 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 greenhouse gas ("**GHG**") emissions by 40% to 45% between 2020 and 2025. The 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 mineral rights 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.

Royalty rates for the production of privately-owned crude oil and natural gas mineral rights 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/or natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and/or natural gas lease agreements between Indigenous communities and producers, and collecting and distributing royalty revenues. The exact terms and conditions of each 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 oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to water use and conservation, 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 legislation and the underlying regulatory requirements, including legislation related to air pollution and GHG emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Shifts in government policy by new or existing requirements or restrictions can impact our operations. Restrictions on fossil fuel-based energy use, emission limits, and new environmental obligations and requirements could have a material adverse impact on the Corporation's business, financial condition, results of operations and prospects.

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.

Impact Assessment Act

The CER has jurisdiction 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 CER reviews applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

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 oil 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.

Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the CER and/or IA Agency will have to issue their report(s) 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.

Clean Fuel Regulations

On June 21, 2022, the *Clean Fuel Regulations* (the "**CF Regulations**") came into force, with the objective to achieve 30 million tonnes of annual reductions in GHG emissions by 2030. The CF Regulations require liquid fossil fuel primary suppliers (i.e. producers and importers) to reduce the carbon intensity ("**CI**") of the liquid fossil fuels they produce in, and import into, Canada. The CF Regulations have also established a credit market, whereby the annual CI reduction requirement can be met via three main categories of credit-creating actions: (i) actions that reduce the CI of the fossil fuel throughout its lifecycle; (ii) supplying low-carbon fuels; and (iii) specified end-use fuel switching in transportation. See "*Industry Conditions – Climate Change Regulation – Federal Policies*".

Regulations Amending the Output-Based Pricing System Regulations and the Environmental Violations Administrative Monetary Penalties Regulation

On November 22, 2023, the federal government published amendments to the Output-Based Pricing System (the "**OBPS Amendment**"). These regulations are made under the *Greenhouse Gas Pollution Pricing Act* (Canada) (the "**GGPPA**"). These changes involve adding and revising output-based standards (*Standards*), enhancing implementation procedures, refining reporting accuracy, and encouraging voluntary participation. Notably, the updated Output-Based Pricing System (the "**OBPS**") introduced a 2% fixed annual tightening rate for most Standards starting from 2023. Sectors facing significant competition and carbon pricing-induced carbon leakage experience a 1% adjusted tightening rate from 2023 onwards. Pursuant to the OBPS Amendment, offset credits or recognized units can be remitted by the same operator under the OBPS and the proposed *Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations* (the *Proposed Emissions Cap Regulations*). See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap

On November 4, 2024, the federal government proposed the Proposed Emissions Cap Regulations. The Proposed Emissions Cap Regulations would establish a cap-and-trade system that would apply to a wide range of industrial activities within the oil and gas sector, including onshore and offshore oil and gas production, oil sands production and upgrading, natural gas production and processing and LNG production. Under the cap-and-trade system, the federal government will determine a maximum threshold for annual emissions and freely issue emissions allowances in an amount equal to the cap. The initial cap would be based on 2026 emissions (attributed according to a formula set out in the Proposed Emissions Cap Regulations). The cap for the first compliance period, from 2030 to 2032, will be 27% below 2026 attributed emission levels for affected facilities. This reduction is anticipated to correspond to a 35% decrease from 2019 emission levels.

By December 31, 2025, operators of all existing prescribed oil and gas facilities would be required to register with the Department of Environment and Climate Change Canada, submit comprehensive annual emissions reports, and undergo independent third-party verification of its emissions data. This reporting threshold applies broadly across the oil and gas sector, which includes monitoring GHG emissions from facilities with significant outputs. Any operators that do not register would be prohibited from emitting GHGs from their industrial activities unless and until registration is completed.

In addition to the emissions-based reporting threshold, any operator producing at or above an annual threshold of 365,000 boe would be classified as a "Covered Operator." Once classified, operators would be subject to remittance obligations under the emissions cap framework. Every Covered Operator would be required to submit one compliance unit for each tonne of emissions produced. There are three categories of compliance units: (i) emission allowances; (ii) decarbonization units; and (iii) certain GHG offset credits.

The cap-and-trade system would be phased in over a four-year period from 2026 to 2029, and so would reporting obligations. Annual reporting requirements would involve two separate reports. One report would be required for each reporting GHG attributed to the facility and a second report would be required that describes the cumulative production of an operator based upon all of its facilities. Operators producing 30,000 or more boe in any month from the beginning of 2024 to July 2025 or those subject to reporting their GHG emissions in 2024 under a subsection 46(1) CEPA notice, must start reporting emissions and production levels for 2026 by June 1, 2027. Operators that do not meet either of these criteria would be required to begin reporting through the submission of an annual report no later than by June 1, 2029, for their 2028 emissions and production levels.

This cap-and-trade system has been criticized by provinces and industry on the basis that it amounts to a production cap and t could have a material adverse impact on the Corporation's business, financial condition, results of operations and prospects. However, with the prorogation of federal parliament on January 6, 2025 and federal election to follow, the future applicability and scope of the Proposed Emissions Cap Regulations is uncertain.

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* (Alberta) (the "**OGCA**"), the *Oil Sands Conservation Act* (Alberta), the *Pipeline Act* (Alberta) and the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"). 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 (the "**AUC**") and the Land and Property Rights Tribunal, 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 (the "**AEPA**") (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 further 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.

On August 14, 2024, Alberta released its Alberta Drought Response Plan (the "**Drought Response Plan**"). The intent of the Drought Response Plan is to ensure Alberta is prepared for the potential of widespread drought. The plan describes preparation, planning and response activities that AEPA will implement to effectively address the full range of possible drought conditions, which may range from localized impacts to multiple river basins simultaneously.

The Drought Response Plan will be led by AEPA and necessitates actions by Alberta Agriculture and Irrigation, Alberta Municipal Affairs, Alberta Forestry and Parks, the AER, and other affiliated ministries. The plan itself is structured around five management stages. Currently, Alberta is situated at stage 4, with the emergent possibility of escalating to stage 5. This fifth stage is characterized as an emergency situation where conventional management strategies may prove inadequate for ensuring access to drinking water, protecting public safety, critical infrastructure, livestock welfare, or vital environmental needs.

Should a water emergency be declared, the plan permits the issuance of water management orders that could result in the suspension of certain authorizations under the *Water Act*, halting water diversion, and strictly regulating the use and allocation of water. These orders, as specified in sections 99 and 107 of the *Water Act*, may also direct necessary actions to counteract or mitigate detrimental effects on aquatic ecosystems or human health.

Additionally, the plan encompasses a range of regulatory and non-regulatory tools to address drought conditions across all stages. Non-regulatory options include advocating for voluntary water conservation and the formation of water-sharing agreements. Regulatory mechanisms comprise the approval of water shortage response plans, issuance of temporary diversion licenses, facilitation of temporary water licence transfers, arrangements for water assignment, and modifications to existing licenses and approvals under the *Water Act*. Other available mechanisms include water management orders that can be enacted under the *Water Act,* alongside environmental and emergency environmental protection orders under the EPEA.

The Drought Response Plan could reduce the availability of water for extraction processes on the Corporation's properties, which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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* and *The Petroleum Registry and Electronic Documents 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 a partner in the Petrinex database.[1]

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.

Saskatchewan launched the Inactive Liability Reduction Program (the "**ILRP**"*)* in January of 2023. The ILRP aims to reduce the total number of inactive liabilities for oil and gas companies. In 2023, the program required oil and gas companies to retire 5% of their inactive liabilities such as inactive wells, and facilities in Saskatchewan. This percentage increased to 6% in 2024 and will remain at 6% for 2025.

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. Following replacement of Alberta's Liability Management Program (the "**AB LMR Program**"), the AER continues to implement its Liability Management Framework (the "**AB LMF**"). The primary goals of the AB LMF are to assist in addressing the Orphan Well Association's (the "**OWA**") inventory and, creating a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project.

As a result of the SCC's decision in *Orphan Well Association v Grant Thornton Ltd.* (also known as the "**Redwater Decision**"), receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without

[1] Petrinex is an online system for volumetric reporting, used by government and industry participants in British Columbia, Alberta and Saskatchewan.

first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. *The Liabilities Management Statutes Amendment Act* places the burden of a defunct licensees' abandonment and reclamation obligations first on the defunct licensee'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 OWA to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be bankrolled exclusively by licensees in the former Alberta Licensee Liability Rating Program (the "**AB LLR Program**") and Alberta Oilfield Waste Liability 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 of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. On March 28, 2024, the AER published *Bulletin 2024-08* prescribing an Orphan Fund Levy of $135 million for the 2024/25 fiscal year. Collectively, these programs were designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. Under the AB LMF, the OWA has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

Following the Redwater Decision, Alberta committed to actively reducing inventories of orphan and inactive well sites in the province. The AB LMF addresses five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) a licensee 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 October 8, 2024, the AER announced an invitation for feedback on revised liability directives, specifically considering the potential rescinding of Directive 006: *Licensee Liability Rating Program*, Directive 024: *Large Facility Liability Management Program* and Directive 075: *Oilfield Waste Liability Program.* 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 oil 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 licensee is required to meet mandatory annual spend targets for well closures and abandonments.

Pursuant to the AER's inventory reduction program implemented under Directive 088: *Licensee Life-Cycle Management*, licensees are required to meet closure spend requirements aimed at mitigating liabilities associated with inactive and orphan wells. The AER prescribes an industry-wide closure spend requirement each year. A licensee's mandatory closure spend is calculated using a licensee's proportion of industry-wide inactive liability and their level of financial distress determined by the licensee capability assessment. Generally, closure spend rates will be lower for licensees experiencing significant financial distress, and higher for licensees experiencing no financial distress. The industry-wide closure spend requirement for 2024 is set at $700 million, and the 2025 requirement is set at $750 million.

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.

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 licensee'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 licensees to submit a $10,000 non-refundable Orphan Fund fee in order to be deemed eligible to transfer licences, and all licensees 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 licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities and this data is publicly available.

In response to the Redwater Decision, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures. 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 has stated it may incorporate additional conditions with licence transfer approvals, however, as of the date of this AIF, no additional conditions have been implemented.

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 licensee 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.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and 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 adverse impact on the Corporation's business, financial condition, results of operations and prospects.

International Treaties and Commitments

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. Canada is a signatory to the Paris Agreement, which is committed to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In January 2025, the United States withdrew from the Paris Agreement and it remains unclear what effect, if any, such withdrawal will have on climate change policies. During the course of the 2021 United Nations Climate Change Conference, Canada pledged to (i) reduce methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) cease to export thermal coal by 2030; (iii) impose a cap on emissions from the oil and gas sector; (iv) halt direct public funding to the global fossil fuel sector by the end of 2022; and (v) commit that all new vehicles sold in the country will be zero-emission on or before 2040. During the 2024 United Nations Climate Change Conference, nearly 200 countries adopted the New Collective Quantified Goal on climate finance and reached an agreement that will triple financing to developing countries for these initiatives. Canada also committed to international action to reduce methane and industrial GHG emissions.

Federal Policies

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 September 4, 2024, the Government of Canada published the 2023 Progress Report. The 2023 Progress Report indicated that Canada is expected to exceed the interim objective of a 20% reduction by 2026.

The Government of Canada's Healthy Environment and a Healthy Economy Plan (the "**HEHE Plan**"), which was adopted in 2021, builds on the Pan-Canadian Framework and provides a roadmap forward to meet Canada's 2030 emissions reduction target, the Government of Canada has agreed to a $8 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.

A change in federal government could lead to a policy shift that could impact the regulatory environment of the oil and natural gas industry.

<u>*Canadian Net-Zero Emissions Accountability Act*</u>

Pursuant to *An Act respecting transparency and accountability in Canada's efforts to achieve net-zero GHG emissions by the year 2050,* Canada joined 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.

Greenhouse Gas Pollution Pricing Act

Canada's GHG regime is enacted pursuant to the GGPPA, which has two parts: the OBPS and a regulatory fuel charge (the "**Fuel Charge**") imposing an initial price of $20/tonne of carbon dioxide equivalent ("**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. 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. The systems will remain until 2027. The minimum carbon pollution price for 2024 is $80/tonne of CO_2e, increasing to $95/tonne of CO_2e on April 1, 2025.

The constitutionality of the GGPPA was challenged by several jurisdictions, with the SCC ultimately upholding its constitutionality. 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 Benchmark. Currently the provincial systems, together with the Fuel Charge apply in each of Alberta, Saskatchewan, Ontario, New Brunswick, Nova Scotia and Newfoundland and Labrador. The provincial plans in each of British Columbia, Québec and the Northwest Territories apply in full in those jurisdictions while the OBPS and Fuel Charge apply in each of Yukon, Nunavut, Manitoba and Prince Edward Island. For so long as the provincial systems in Alberta (under the *Technology Innovation and Emissions Reduction* ("**TIER**") *Regulation*), British Columbia 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.

Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds

On October 29, 2020, the federal government launched the $750 million Emission Reduction Fund to reduce methane and GHG emissions. The fund provides repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies. Part of this fund is directed towards methane reduction. The *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**") aim to reduce methane emissions from the oil and natural gas industry by implementing control measures to minimize unintentional leaks and intentional venting of methane. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

On December 4, 2023, the Minister of Environment and Climate Change announced proposed amendments to the Federal Methane Regulations to further reduce emissions. These amendments align with international efforts, such as the International Energy Agency's call to curtail methane emissions from the oil and gas sector by 75% by 2030. The draft amendments were open for public consultation until February 14, 2024. The Government of Alberta has opposed the amendments, stating it will take measures to ensure the amended regulations are not implemented in Alberta. It is unknown at this time what the potential effects of the amended Federal Methane Regulations may be.

On March 11, 2024, the Minister of Energy and Natural Resources officially launched Canada's Methane Centre of Excellence and a request for proposals for methane mitigation and measurement projects. The Methane Centre of Excellence was instituted as a result of Minister of Environment and Climate Change's announcement of a $30 million investment in December 2023.

Clean Fuel Regulations

The CF Regulations came into force on June 21, 2022, implementing the *Clean Fuel Standard*. The CF Regulations take a performance-based approach to reducing GHG emissions and 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 gCO_2e/MJ, increasing by 1.5 gCO_2e/MJ each year and reaching 14 gCO2e/MJ in 2030. The standard applies 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 CF Regulations offer compliance credits, tracked via the Credit and Tracking System, and create a credit market to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

Clean Electricity Regulation

The *Clean Electricity Regulations* enacted on December 18, 2024, are the culmination of nearly three years of feedback from provinces, territories, Indigenous communities, and industry. Initially released in August 2023, the draft CER received significant pushback, particularly regarding the prohibition against electricity generation units emitting more than an annual average of 30 tonnes of carbon emissions per GWh (t/GWh) of electricity generated. In response, the federal government updated the proposed *Clean Electricity Regulations* in February 2024, introducing key changes such as unit-specific annual emission limits and the possibility of exceeding these limits through the remittance of offset credits. Notably, the now-finalized *Clean Electricity Regulations* pushed back the target date to decarbonize electricity grids from 2035 to 2050. Though enacted in December 2024, the emission restrictions under the *Clean Electricity Regulations* will not come into effect until January 1, 2035, with the goal of reaching net-zero by 2050.

Under the *Clean Electricity Regulations*, electricity generating units that meet the applicability criteria will be subject to an annual emission limit based on each unit's generation capacity. A "unit" means an assembly consisting of equipment that is physically connected and operate together to generate electricity.

The *Clean Electricity Regulations* applies to a unit that meets the following criteria: (i) the unit uses any amount of fossil fuels to generate electricity, (ii) the unit has a generation capacity of at least 25 megawatts, and (iii) the unit is connected to an electricity system that is subject to the North American Electricity Reliability Corporation's standards. The regulations also permit the exclusion of emissions associated with the combustion of biomass and renewable natural gas, as well as emissions captured by carbon capture and storage projects and emissions generated during an emergency circumstance.

Air Pollutant Regulations

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

Framework to Phase Out Fossil Fuels

On July 24, 2023, the Minister of Environment and Climate Change released the *Inefficient Fossil Fuel Subsidies Government of Canada Self-Review Assessment Framework* and the *Inefficient Fossil Fuel Subsidies Government of Canada Guidelines*. The documents will support the federal government's focus on clean energy and net-zero initiatives and the de-carbonization of Canada's oil and gas sector. Pursuant to the framework, subsidies are deemed "inefficient" unless they satisfy certain criteria, which include, but are not limited to: supporting clean energy, clean technology, or renewable energy; providing essential energy service to a remote community; providing short-term support for emergency response; supporting Indigenous economic participation in fossil fuel activities; or supporting abated production processes, such as carbon capture, utilization, and storage, or projects that have a credible plan to achieve net-zero emissions by 2030. The federal government has proposed a framework for assessing fossil fuel subsidies to identify any potential "inefficient fossil fuel" subsidies. The majority of the subsidies that may be deemed to be inefficient are tax subsidies for the oil and gas sector and the mining sector. The federal government had conducted a preliminary review of various subsidies but has yet to make any concrete decisions respecting the phasing out of such subsidies. With the prorogation of federal parliament on January 6, 2025 and a potential federal election to follow, the future applicability and scope of these federal guidelines is uncertain.

Bill C-59 – Anti-Greenwashing Legislation

In June 2024, Bill C-59, an *Act to implement the Fall Economic Statement* ("**Bill C-59**"), received royal assent. Bill C-59 introduced significant updates to the *Competition Act* with implications for environmental claims and collaborations. The amendments expand the *Competition* Act's deceptive marketing provisions, requiring businesses making environmental claims about products or business practices to substantiate their statements with "adequate and proper tests" or internationally recognized methodologies. Failure to comply may result in penalties of up to 3% of worldwide revenues and reputational damage. Starting June 20, 2025, private parties will also be allowed to bring deceptive marketing claims before the Competition Tribunal, a right previously exclusive to the Competition Bureau. The introduction of Bill C-59 increases compliance risks for energy industry participants that make public environmental claims or engage in marketing respecting environmental responsibility.

Alberta

In 2019 the Fuel Charge took effect in Alberta. In accordance with the GGPPA, the Fuel Charge payable in Alberta is currently \$80/tonne of CO_2e and will increase to \$95/tonne on April 1, 2025. 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 TIER regulation applies to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. Starting in 2020, most TIER-regulated facilities were required to reduce emission intensity by 10%, with an additional 1% annual reduction thereafter. Recent amendments introduced a 2% annual tightening rate for facility-specific and high-performance benchmarks, replacing the previous facility-specific benchmarks for some facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, while facilities with significant prior reductions can use a high-performance benchmark to account for compliance costs. Facilities emitting 2,000 to 10,000 tonnes of CO_2e annually can now opt into the program under amended thresholds. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and, may meet thresholds by either purchasing credits from other facilities, purchasing carbon offsets, or paying a levy to the Government of Alberta. 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.

In furtherance of global emissions reductions targets, the Government of Alberta had announced a goal to lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020 and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting* ("**Directive 060**"). The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* ("**Directive 017**") that took effect in December 2018. In November 2023, it was announced that Alberta had achieved its goal of reducing methane emissions by 45% by 2025, years ahead of schedule.

In May 2020, the Government of Canada and the Government of Alberta announced a preliminary equivalency agreement (the "**Equivalency Agreement**") regarding the reduction of methane emissions. Through the Equivalency Agreement and Directive 060 and Directive 017, Alberta maintains jurisdiction over the regulation of the upstream oil and gas industry. Should amendments to the Federal Methane Regulations come into effect and the Government of Alberta challenges such amendments, the potential effects of such legislation in Alberta, or the effects of any potential challenge to their implementation by the Government of Alberta is unknown.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap, outlining its potential to lead global and national decarbonization. Phase one focuses on policy, technology investments and supply chain commercialization, while phase two aims to scale production and commercialization. The AUC 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.

In February 2023, the TIER regulation was amended to, among other things, amend the opt-in thresholds for emissions-intensive and trade-exposed industries, tighten facility-specific benchmarks, revise the credit use limits and expiration periods as well as create sequestration credits for carbon capture, utilization and storage projects. The TIER regulation will be subject to a subsequent review which must be completed by December 31, 2026.

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 the Quest and Alberta Carbon Trunk Line projects. In 2024, the Government of Alberta announced the Alberta Carbon Capture Incentive Program (the "**ACCIP**") which offers a 12% grant on new eligible CCUS capital costs and is designed to complement the federal incentives. The ACCIP is intended to support Alberta's strategy to stay at the forefront of CCUS development and environmental sustainability.

Saskatchewan

The *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") regulates 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* 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 includes credits for emitters utilizing CCUS technologies at their facilities. As noted above, the 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, requiring facility licensees exceeding 50,000 tonnes of CO_2e annually to submit emissions reduction plans. These aim to cut annual emissions by 40% to 45% by 2025, achieving reductions of 4.5 million tonnes of CO_2e emissions by 2025 and 38.2 million tonnes of CO_2e emissions 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. The 2023 Climate Resilience Report indicated that roughly 34.7% of SaskPower's electrical generation came from renewable sources in 2022. The report also suggests that total GHG emissions in 2022 are already below the 2025 target initially set.

In October 2019, *The Oil and Gas Conservation Amendment Act* was proclaimed into force, which 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 July of 2024, the Government of Saskatchewan and the federal government entered into an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on December 31, 2029.

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 legislation 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/tonne charge.

Following Manitoba's challenge of the GGPPA 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. The federal system under the GGPPA therefore applies in full in Manitoba, resulting in a price of $80/tonne of CO_2e in 2024 and increasing to $95/tonne of CO_2e beginning April 1, 2025.The original *Climate and Green Plan Implementation Act* 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 to 2022 period. The Government of Manitoba set the reduction target for the second five-year period (2023 to 2027) at 5.6 megatonnes of CO_2e emulative emissions reductions.

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 communities), 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.

Bill S-211, *An Act to enact the Fighting Against Forced Child Labour in Supply Chains Act and to amend the Customs Tariff* (the "**Modern Slavery Act**") received royal assent on May 11, 2023 and came into force on January 1, 2024. Pursuant to the Modern Slavery Act, entities that meet certain criteria are required to file public reports annually on the steps they have taken to prevent and reduce the use of forced labour and child labour in their supply chains. This includes entities engaged in producing, selling, or distributing goods in Canada or elsewhere, importing into Canada goods produced outside Canada, or controlling an entity engaged in either of the preceding activities. The bill outlines the steps these entities must take to prevent and reduce the risk that operations, including those of third parties within the supply chain, make use of forced and/or child labour. The Corporation is required to comply with the reporting obligations under the Modern Slavery Act. See "*Risk Factors – Evolving Corporate Governance, Sustainability and Reporting Framework*".

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous communities potentially 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 Act* ("**UNDRIP**") and the principles set forth therein, including the principle to seek free, prior and informed consent, may continue to influence the role of Indigenous engagement in the development of the oil and natural gas industry in Western Canada.

UNDRIP 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. In 2023, the Government of Canada released the 2023-2028 Action Plan, which sets out a roadmap for advancing reconciliation with Indigenous peoples based on recognition of rights, respect, cooperation, and partnership. It is uncertain as to what potential consequences the implementation of these action plans and their effects on future legislative drafting may have.

The federal government has expressed that implementation of the UNDRIP 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 Supreme Court of Canada, the IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP. 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 UNDRIP 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. On February 9, 2024, the Supreme Court of Canada rendered its decision regarding the *Reference re An Act respecting First Nations, Inuit and Métis children, youth and families*, in which it made clear its opinion that UNDRIP has been incorporated into Canada's domestic positive law.

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 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.

Credit Facility Risks

The amounts authorized under the Credit Facility 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 SCC 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 business, financial condition, results of operations and prospects 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*"). 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, including, but not limited to global and regional supply of, and demand for, these commodities; the ability of producers and governments to replace reduced supply; processing and export capacity; export restrictions; domestic and global economic conditions; political uncertainty; the threat or imposition of tariffs or other restrictive trade measures; sanctions imposed on certain oil producing nations by other countries; inflation and changes to interest rates; increased or retaliatory tariffs; central bank policies; market competitiveness; the actions of OPEC and other oil exporting nations, including, but not limited to, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC not to impose production quotas on its members; developments related to the market for these commodities; inventory levels of these commodities; seasonal trends; refinery availability; current and potential future environmental laws and regulations; emissions, including, but not limited to carbon; market pricing and the accessibility and liquidity of these and related markets; prices and availability of alternate sources of energy; actions of domestic or foreign governments or regulatory bodies; enforcement of government or environmental laws and regulations; shifts or changes in governmental policy as a result of new or existing administrations in the jurisdictions in which the Corporation conducts its operations, development or exploration; public sentiment towards the use of non-renewable resources; political instability and social conditions in countries producing these commodities; market access constraints and transportation restrictions or interruptions; terrorist threats; technological developments; economic sanctions; outbreak or continuation of a pandemic, or war or other international or regional conflict and any related government action or military exercise; the occurrence of natural disasters; and weather conditions.

The recent increase in focus on the timing and pace of the transition to a lower-carbon economy and resulting trends will likely affect global energy demand and usage, including the composition of the types of energy generally used by industry and individual consumers. Under certain aggressive low-carbon scenarios, potential demand erosion could contribute to commodity price fluctuations and structural commodity price declines. However, it is not currently possible to predict the timelines for, and precise effects of, the transition to a lower-carbon economy.

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, financial condition, results of operations and prospects. See "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*".

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. Tariffs or other restrictive measures or countermeasures affecting trade between Canada and the United States, such as those imposed by the Executive Order could have a significant impact on the market for oil and natural gas products and could result in, among other things, a high degree of both cost and price volatility, a relative weakening of the Canadian dollar, widening differentials, decreased demand for the Corporation's products and decreased activity on the Corporation's properties. Any or all such effects may have a material adverse impact on the Corporation's business, financial condition, results of operations and prospects. Limitations on the ability of Western Canadian energy producers to export crude oil, NGLs and natural gas to United States markets and other world markets and the resulting discount that Western Canadian energy producers may receive for their products as compared to the united States and international benchmark commodity prices could negatively impact the Corporation's business, financial condition, results of operations, prospects and the market value of its Common Shares which adverse effect could provide to be material over time.

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, 2024 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. Any decrease in value of the Corporation's reserves could result in a reduction of the borrowing base under the Credit Facility. See "*Risk Factors – Credit Facility Risks"*.

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 and 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*".

Emerging Risks

In recent weeks, the new U.S. administration issued the Executive Order directing the United States to impose new tariffs on imports from certain countries, including a 10% tariff on "energy and energy resources" from Canada, which came into effect on March 4, 2025. The implementation of the tariffs, including the retaliatory tariffs imposed by Canada in response and any further potential tariff response strategy by either country may create uncertainty, which has permeated the economic and investment outlook, impacting current economic conditions, including such issues as the inflation rate and the global supply chain. Aside from its impact on the global economy, the new tariff conflict may have an adverse effect on the Corporation's business, financial condition, results of operations and prospects, which adverse effect could prove to be material over time.

In light of these recent developments, the Corporation is closely monitoring the impacts and potential consequences on its business, financial condition, results of operations and prospects. Given these circumstances, this conflict may put into perspective many of the top and emerging risks to which the Corporation is exposed, including credit risk, commodity pricing and market risk, liquidity and funding risk, operational risk, strategic risk and third-party risk. The extent to which the Corporation's business, financial condition, results of operations and prospects will be affected depends largely on the nature and duration of uncertain and unpredictable events, such as the duration or escalation of the tariffs, the evolution of retaliatory measures, possible fiscal or monetary policy responses, and reactions to ongoing changes by global financial markets.

Political Uncertainty

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

With the prorogation of federal parliament on January 6, 2025, and the federal election to follow, there is a greater uncertainty within the Canadian political landscape. The future applicability and scope of proposed federal regulations that have not yet been enacted is uncertain. A change in federal government, including the new Trump administration in the United States, could lead to a policy shift that could impact the regulatory environment of the oil and natural gas industry and may have a material impact on the Corporation's business, financial condition, results of operations and prospects.

Other government and political factors that could have a material adverse effect the Corporation's business, financial condition, results of operations and prospects, including increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements, including the expansion of the scope and duration of tariffs imposed by the Executive Order including the imposition of other restrictive trade measures, countermeasures or retaliatory tariffs. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could reduce the demand for oil, natural gas and NGLs. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The success of these initiatives may decrease demand for the Corporation's products.

A change in federal, provincial, state or municipal governments in Canada or the United States may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic, resulting in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Corporation's activities. See "*Industry Conditions – 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*".

International Conflicts and Geopolitical Risk

Conflicts, or conversely peaceful developments, arising outside of Canada, including conflicts in Palestine and Ukraine and changes in political regimes or parties in power, may have a significant impact on the price of oil and natural gas. Any particular event could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Unrest continues in the Middle East and the outcome of the Israel-Hamas conflict in the Gaza Strip has the potential to have wide-ranging consequences on the world economy. A temporary ceasefire came into effect in January 2025 which will be executed in three stages. While neither Israel nor the Gaza Strip are significant oil producers, and despite the ceasefire, there remains a risk that any new conflict or breakdown of the existing ceasefire, could lead to wider regional instability in the Middle East, home to some of the world's largest oil producers.

In addition, attacks by Houthi rebels in the Red Sea has put significant risks on shipping lanes in the area and has resulted in increased shipping costs to various business entities. Continued attacks on shipping in the Middle East may result in further increases in shipping costs and longer transit times and delays in delivering products or procuring supplies. Throughout 2024, conflict arose in other Middle East countries such as Iran, Syria and Lebanon, with potential for escalation and intervention by Western countries like the United States. Further escalation of the conflict may spark confrontations in other parts of the Middle East and have further adverse consequences on global markets, commodity prices, supply chains and shipping lanes. The Corporation continues to monitor these events although there is no assurance that the Corporation's business, financial condition, results of operations and prospects will not be materially adversely affected by current geopolitical tensions and/or associated government sanctions.

In February 2022, Russian military forces invaded Ukraine. Ukrainian military personnel and civilians continue to actively resist the invasion. Certain countries including Canda, have imposed strict financial and trade sanctions against Russia. The outcome of the ongoing conflict remains uncertain and may have wide-ranging consequences on the peace and stability of the region and the world economy.

Global Financial Markets

The market events and conditions that transpired in recent years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have, among other things, caused significant volatility in commodity prices. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors negatively impacted enterprise valuations and impacted the performance of the global economy. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties regarding the supply and demand fundamentals for petroleum products due to the current state of the world's economies, actions taken by OPEC, the ongoing risks facing the North American and global economies and increased supplies of crude oil which may be created by the application of new drilling technology to unconventional resource plays.

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 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. 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.

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 oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to 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 oil 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 adverse effect 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, prospects and reputation. 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 NGLs. 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 NGLs. The Corporation cannot predict the impact of changing demand for crude oil and natural gas products, and any major changes may have an adverse effect on the Corporation's business, financial condition, results of operations and prospects 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 adverse effect could prove to be material over time.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering, processing facilities and pipeline systems, none of which are owned by the Corporation. The amount of crude oil and natural gas produced by the Corporation is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits, and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced crude oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of crude oil and natural gas companies to export crude oil and natural gas, and could result in the inability of third parties to realize the full economic potential of the produced crude oil or natural gas or a reduction of the price offered for the Corporation's production. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work, natural disasters and environmental conditions, or because of actions taken by regulators could also affect third parties' production and operations which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. As a result, producers have considered rail lines as an alternative means of transportation.

Future pipeline projects may be terminated for reasons such as a failure to obtain government and/or regulatory support or approval. The direct impact that the termination of such projects will have on the Corporation is unknown.

Federal and various provincial governments have been active in recent years in their support for and opposition to major infrastructure projects in Canada, leading to increased awareness and challenges to interprovincial and international infrastructure projects. On August 28, 2019, the CERA and the IAA came into force and the NEB Act and the Canadian Environmental Assessment Act, 2012 were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency. In the fall of 2023, the SCC found the IAA to be unconstitutional and the federal government is currently in the process of revising the IAA in an effort to make it compliant. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". Projects which are subject to an impact assessment under both provincial and federal legislation, will likely be subject to a robust assessment of the environmental, social, health, economic and cultural impacts of the proposed project subject to the legislation. In addition, the effects of projects on Indigenous communities and their constitutionally protected rights may lead to longer periods to conduct the assessment and potentially more opportunities for public engagement and consultation. The Corporation's production is processed through facilities owned by third parties over which the Corporation, have no control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the ability of the Corporation to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

The Corporation has certain long-term take-or-pay commitments to deliver products through third-party owned infrastructure which creates a financial liability and there can be no assurance that future volume commitments will be met which may adversely affect the Corporation's business, financial conditions, results of operations and prospects. Deliverability uncertainties related to the distance the Corporation's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities, as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of crude oil and natural gas and other aspects of the oil and natural gas industry may also affect the Corporation. See "*Risk Factors – Commodity Prices, Markets and Marketing*".

Regulatory

The implementation of new laws and regulations or the modification of existing laws and regulations affecting the oil 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 the Corporation's business, financial condition, results of operations, prospects and reputation. Shifts or changes in governmental policy, including as a result of new or existing administrations in the jurisdictions in which the Corporation conducts its business may have an impact on the laws and regulations affecting the oil and natural gas industry, as well as the Corporation. Further, third-party challenges to regulatory decisions or orders can reduce the efficiency of the regulatory regime by delaying decisions resulting in uncertainty and interruption to business of the oil 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 that 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, financial condition, results of operations and prospects. 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, results of operations, prospects 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*" and "*Industry Conditions – 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 oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. See "*Industry Conditions – Pricing and Marketing in Canada – 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. The Corporation believes that it is in material compliance with current applicable environmental legislation; 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 an adverse effect on the Corporation's business, financial condition, results of operations and prospects, which adverse effect could prove material over time.

Stakeholders, Indigenous communities, 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, financial condition, results of operations and prospects. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation*".

Liability Management

We are subject to oil and gas asset abandonment, remediation and reclamation liabilities for our operations, development and exploration, including those imposed by regulation under various levels of legislation in the jurisdictions in which the Corporation conducts its operations, development or exploration.

We maintain estimates of our abandonment, remediation and reclamation liabilities; however, it is possible that these costs may change materially before decommissioning due to regulatory changes, technological changes, ecological risks, acceleration of decommissioning timelines, and inflation, among other variables.

In Alberta, Saskatchewan and Manitoba, the abandonment, remediation and reclamation liability regimes include orphan well funds that are funded through a levy imposed on licensees, including the Corporation, based on the licensees' proportionate share of the deemed abandonment, remediation and reclamation liabilities for oil and gas facilities, wells and unreclaimed sites. The regulators in these jurisdictions may seek additional funding for such liabilities from industry participants, including the Corporation.

We have an ongoing environmental monitoring program of owned and leased retail locations, and former owned or leased retail locations where we have retained environmental liability, and perform remediation where required to comply with contractual and legal obligations. The costs of such remediation may not be determinable due to the unknown timing and extent of corrective actions that may be required. The impact on our business of any legislative, regulatory or policy decisions relating to the abandonment, remediation and reclamation liability regulatory regime in the jurisdictions in which the Corporation conducts its operations, development or exploration cannot be reliably or accurately estimated. Any cost recovery or other measures taken by applicable regulatory bodies may impact the Corporation and could materially and adversely affect, among other things, our business, financial condition, results of operations, prospects and reputation.

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 business, financial condition, results of operations and prospects of the Corporation impacting future capital investment which could reduce the Corporation's business, financial condition, results of operations and prospects. See “*Industry Conditions – Land Tenure – Royalties and Incentives*”.

Climate Change

There is growing international and domestic concern regarding climate change and a significant increase in focus on the timing and pace of the transition to a lower-carbon economy. Governments, financial institutions, insurance companies, non-governmental organizations, environmental and governance organizations, institutional investors, social and environmental activists, shareholders and individuals are increasingly seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends which, individually and collectively, are intended to or have the effect of accelerating the reduction in the global consumption of fossil fuel-based energy, the conversion of energy usage to less carbon- intensive forms and the general migration of energy usage away from fossil fuel based forms of energy.

Climate change and its associated impacts may increase the Corporation’s exposure to, and magnitude of, each of the risks identified in this AIF. The Corporation is unable to estimate the degree to which climate change-related regulatory, climatic conditions, and climate-related transition risks could affect the Corporation’s business, financial condition, results of operation and prospects. See “*Industry Conditions – Climate Change Regulation*”.

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 business, financial condition, results of operations and prospects.

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, the demand for and price of the Corporation's securities may negatively impact the Corporation's cost of capital and access to the capital markets, which adverse effect 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 and governance ("**ESG**") and climate reporting, on June 26, 2023, the International Sustainability Standards Board issued its first two IFRS Sustainability Disclosure Standards, IFRS S1 - *General Requirements for Disclosure of Sustainability-related Financial Information* and IFRS S2 - *Climate-related Disclosures,* with the purpose of developing sustainability disclosure standards that are globally consistent, comparable, transparent and reliable. Similarly, using the IFRS Sustainability Disclosure Standards as a baseline, the Canadian Sustainability Standards Board has released its own two sustainability disclosure standards modified for the Canadian context, the Canadian Sustainability Disclosure Standard 1 - *General Requirements for Disclosure of Sustainability-related Financial Information* and Canadian Sustainability Disclosure Standard 2 - *Climate-related Disclosures.*

In addition, the Canadian Securities Administrators is developing 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 an adverse effect on the Corporation's business, financial condition, results of operations and prospects, which adverse effect 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 oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. 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 an adverse effect on the Corporation’s production which adverse 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 flooding, most recently with wildfires in Alberta, 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.

Marketing Practices – Anti-Greenwashing Legislation

Recent updates to the *Competition Act*, which expand the *Competition Act’s* deceptive marketing provisions, require businesses making environmental claims about products or business practices to substantiate their statements with “adequate and proper tests” or internationally recognized methodologies. Failure to comply may result in penalties of up to 3% of worldwide revenues and reputational damage. Starting June 20, 2025, private parties will also be allowed to bring deceptive marketing claims before the Competition Tribunal, a right previously exclusive to the Competition Bureau. See “*Industry Conditions – Climate Change Regulation*”.

The Corporation's efforts to comply with these and other new and existing rules and regulations are likely to result in increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities. In addition, the Corporation may become involved in, named as a party to, or be the subject of, various legal claims and proceedings. 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, results of operations and prospects. 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, financial condition, results of operations and prospects.

ESG and Sustainability Matters

Companies across all industries, but particularly in the oil and natural gas industry, may face scrutiny from government and stakeholders related to their ESG and sustainability practices. Some capital markets participants use certain components of ESG as a factor in their valuation of companies, which could impact the Corporation’s cost of capital or access to financing. There has also been an acceleration in investor demand for ESG investing opportunities, and many institutional investors have committed to increasing the percentage of their portfolios that are allocated towards ESG-focused investments. As a result, there has been a proliferation of ESG focused investment funds and market participants seeking ESG-oriented investment products. There has also been an increase in third-party providers of company ESG ratings and rankings, and an increase in ESG-focused voting policies among proxy advisory firms, portfolio managers, and institutional investors. Currently, there are no universal standards for such ratings, rankings and voting policies, they often differ based on the provider and the data they prioritize is continually changing; however, such ratings, rankings and voting policies may be used by some investors to inform their investment and voting decisions.

Additionally, certain investors may use these ratings or rankings to benchmark companies against their peers, and if a company is perceived as lagging, these investors may engage with the Corporation to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a company's sustainability rating or ranking as a reputational or other factor in making an investment decision. Consequently, a low sustainability rating or ranking could result in exclusion of the Corporation's shares from consideration by certain investment funds, engagement by investors seeking to improve such ratings or rankings and a negative perception of the Corporation's business by certain investors. Additionally, to the extent ESG matters negatively impact the Corporation's reputation, it may not be able to compete as effectively to recruit or retain employees, which may adversely affect its operations. Furthermore, there has recently been backlash from certain governments and investors against ESG funds and investment practices, which has resulted in increased scrutiny and withdrawals from such funds. Such backlash has also resulted in "anti-ESG" focused activism and investment funds, which may result in additional strains on the Corporation's resources.

The Corporation also makes certain disclosures regarding sustainability from time to time, including publishing its Sustainability Report that provides updates on its performance related to certain ESG topics. Many of the Corporation's disclosures are necessarily based on estimates and assumptions that are inherently difficult to assess and may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Public statements with respect to ESG matters, including GHG emissions reduction goals, environmental targets, or, more broadly, ESG-related goals, are becoming increasingly subject to heightened scrutiny from public and governmental authorities with respect to the risk of potential "greenwashing," i.e., misleading information or false claims overstating potential ESG benefits and are now subject to greater scrutiny as a result of the enactment of Bill C-59, as discussed above, and within a year, potential private actions thereunder. As a result, the Corporation may face increased litigation risks from private parties and governmental authorities related to its ESG efforts which could, in turn, lead to further negative sentiment and diversion of investments. The Corporation could also face increasing costs to comply with increased regulatory focus and scrutiny. To the extent that the Corporation is unable to respond timely and appropriately to any negative publicity, its reputation could be harmed. Damage to its overall reputation could have a material adverse impact on the Corporation's business, financial condition, results of operations and prospects, including its share price, and require additional resources to rebuild the Corporation's reputation.

The Corporation may not be able to meet ESG targets in the manner, or on such a timeline as initially contemplated, including as a result of the significant time commitment from the Board, management and employees to implement such goals and policies, unforeseen costs, consequences or technical difficulties associated with achieving such results.

Exposure to Widespread Pandemic and Risks Related Thereto

Pandemics, epidemics or outbreaks, remain a risk for the Corporation, and the ultimate impact of a pandemic is highly uncertain and subject to change. A pandemic and the corresponding measures we take to protect the health and safety of our staff, and the continuity of our business may result in new legal challenges and disputes, including, but not limited to, litigation involving contract parties or employees and class action claims. Actions taken by various levels of government and health authorities in the event of a pandemic, epidemic or outbreak may result in a reduction in the demand for, and prices of, commodities that are closely linked to our financial performance and may negatively impact our business, financial condition, results of operations, prospects and reputation.

Natural Disasters, Terrorist Act, Civil Unrest, Pandemics and Other Disruptions and Dislocations

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on the Corporation and its customers. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses, civil unrest and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations, prospects and other factors relevant to the Corporation, its customers and its 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, prospects and reputation.

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 business, financial condition, results of operations and prospects.

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, results of operations and prospects.

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.

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 and monitoring of 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, financial condition, results of operations, prospects and reputation.

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 an adverse effect 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, prospects and reputation.

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 oil 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 communities and peoples, 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 adverse effect 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, financial condition, results of operations, prospects and reputation.

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. There is also uncertainty regarding what impacts, if any, the federal election expected to occur in 2025 will have on emissions reduction and carbon pricing in Canada. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation"* and "*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.

Uncertainty of Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future net revenue attributed to such reserves. The reserves and associated future net revenue information set forth in this AIF are estimates only. In general, estimates of economically recoverable oil, natural gas and NGL reserves and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, commodity prices, production rates, ultimate reserves recovery, the timing and amount of capital expenditures by the working interest owners thereon, marketability of oil, natural gas and NGL, royalty rates, 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 oil, natural gas and NGL reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenue associated with reserves prepared by different engineers, or by the same engineer at different times, may vary. The Corporation's actual production, revenue, 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 and such variations could be material.

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

Actual production and cash flow derived from the Corporation's reserves will vary from the estimates contained in the Corporation's independent reserves evaluation and such variations could be material. The independent reserves evaluation is based in part on the assumed success of activities the Corporation intends to take in future years. The reserves and estimated future net revenue to be derived therefrom and contained in the Corporation's independent reserves evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the evaluation.

The Reserves Report is effective as of December 31, 2024, with a preparation date of February 7, 2025, and, except as may be specifically stated or required by applicable securities laws, has not been updated since that date and therefore does not reflect changes since that date.

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, 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 business, financial condition, results of operations and prospects 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, results of operations and prospects. 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, financial condition, results of operations and prospects.

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 an adverse effect on the Corporation's business, financial condition, results of operations and prospects, which adverse 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 an adverse effect on the Corporation's business, financial condition, results of operations and prospects, which adverse 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 communities 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 an adverse effect on the Corporation's business, financial condition, results of operations and prospects, which adverse effect could prove to be material over time. See "*Industry Conditions - Indigenous Rights*".

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, prospects and reputation. 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 crude oil, natural gas, NGL and refining industry is highly competitive in all aspects, including access to capital, the exploration and development of new and existing sources of supply, the acquisition of crude oil and natural gas interests and the refining, distribution and marketing of oil and gas products. We compete with other producers, refiners and marketers, some of which may have lower operating/capital costs or higher quality resource inventory than our Corporation does. Competitors may develop and implement technologies and business practices which are superior to those we employ. Competitors may assemble portfolios that generate stronger financial returns than Cenovus does, reducing our ability to compete. The crude oil, natural gas, NGL and refining industry also competes with other industries in supplying energy, fuel and related products to consumers, including renewable energy sources which may become more prevalent in the future. We may not be able to compete successfully against current and future competitors, and competitive pressures could have a material adverse effect on our business, reputation, financial condition, results of operations and prospects.

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 an adverse effect on the Corporation's business, financial condition, results of operations and prospects, which adverse effect could prove to be material over time.

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 and 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 business, financial condition, results of operations, prospects 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 oil 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 oil 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, financial condition, results of operations, prospects and reputation.

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 oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in 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 oil and natural gas industry, and more specifically, the Corporation, may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares, even if the Corporation's business, financial condition, results of operations, prospects and underlying asset value 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 Accounting Standards Board and the Canadian Sustainability 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, results of operations and prospects may be negatively impacted, which adverse effect 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 oil 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 oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil 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, prospects and reputation 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, prospects and reputation 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 oil 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, NGL 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 oil and natural gas industry such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

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.

Credit Ratings

Credit ratings are intended to provide an independent measure of the credit quality of an issuer of securities and are subject to ongoing evaluation by credit rating agencies. The credit rating assigned by a rating agency is not a recommendation to purchase, hold or sell securities nor does the rating comment on market price or suitability for a particular investor. A rating may not remain in effect for any given period of time and may be revised or withdrawn entirely by a rating agency at any time in the future, if, in its judgment, circumstances so warrant. There can be no assurance that a credit rating will be maintained in the future. Downgrades in the Corporation’s credit rating could adversely affect the Corporation’s business, financial condition, results of operations, prospects and share and debt prices.

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 an adverse effect on the Corporation's reputation, performance and earnings, which adverse 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.

Artificial Intelligence and Data Protection

The protection of customer, stakeholder, employee, and Corporation's data is critical to the Corporation's business. The regulatory environment in Canada surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and constantly changing requirements. Certain legislation, including the *Personal Information Protection and Electronic Documents Act* in Canada, require documents to be securely destroyed to avoid identity theft and inadvertent disclosure of confidential and sensitive information. A significant breach of customer, stakeholder, employee, or the Corporation's data could attract a substantial amount of media attention, damage the Corporation's customer relationships and reputation, and result in lost revenue, fines, or lawsuits. The continued emphasis on information security as well as increasing concerns about government surveillance may lead customers to request the Corporation to take additional measures to enhance security and/or assume higher liability under its contracts. As a result of legislative initiatives and customer demands, the Corporation may have to modify its operations to further improve data security. Any such modifications may result in increased expenses and operational complexity, and adversely affect its business, financial condition, results of operations, prospects and reputation.

Additionally, the Corporation's information technology systems may incorporate the use of artificial intelligence ("**AI**") and development of such capabilities remain ongoing. As with new innovations, AI presents risks, challenges and unintended consequences that could affect its adoption, and therefore the Corporation's business. AI algorithms and training methodologies may be flawed. The use of AI to support business of the Corporation, its partners, vendors, suppliers, contractors, or others carries inherent risks related to data privacy and cybersecurity, such as intended, unintended, or inadvertent transmission of proprietary or sensitive information, as well as challenges related to implementing and maintaining AI tools, including the development and maintenance of appropriate datasets for such support. Dependence on AI without adequate safeguards to make certain business decisions may introduce additional operational vulnerabilities, by producing inaccurate outcomes based on flaws or deficiencies in the underlying data or other unintended results. Further, AI tools or software may rely on data sets to produce derivative work which may contain content subject to license, copyright, patent or trademark protection or sensitive personal information and can produce outputs that infringe on intellectual property rights or compromise privacy of individuals or organizations, raising concerns about data privacy. As AI is an emerging technology for which the legal and regulatory landscape is not fully developed, including potential liability for breaching intellectual property or privacy rights or laws, new laws and regulations applicable to AI initiatives remains uncertain, and the Corporation's obligation to comply with such laws could entail significant costs, negatively affecting the Corporation's business or limiting the Corporation's ability to incorporate certain AI capabilities into its business.

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.

MATERIAL CONTRACTS

Except for those contracts listed below and contracts entered into in the ordinary course of business, the Corporation did not enter into any material contracts within the most recently completed financial year, or before the most recently completed financial year but which are still in effect. Particulars of such material contracts can be found under "*Description of Capital Structure – Debentures*", "*Description of Capital Structure – Senior Notes*" and "*Description of Capital Structure – Credit Facility*".

- Debenture Indenture;
- Senior Notes Indenture; and
- Credit Facility.

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, 2024, 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

Michael Bennett, the Corporate Secretary of the Corporation, is 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 that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

The transfer agent and registrar for the Common Shares is Odyssey Trust Company of Canada 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, 2024 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 one 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.sedarplus.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 2024. Additional financial information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2024.

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, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, 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, 2024, 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, 2024	Canada				
Total			**Nil**	**1,691,623**	**Nil**	**1,691,623**

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, 2024)".

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

Sproule

Executed as to our report referred to above:

Sproule International Limited
Calgary, Alberta

"Original signed by Maria Herrera, P. Eng."

Maria Herrera, P. Eng.
Senior Petroleum Engineer
DATE: February 10, 2025 RM APEGA ID#: 90581

Sproule International Limited
APEGA Permit Number 06151

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

Gary R. Finnis, P. Eng.
Senior Manager, Engineering
DATE: February 10, 2025 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, 2024, 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, 2024 (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) "P. Daniel O'Neil"	*(signed) "Daryl Gilbert"*
P. Daniel O'Neil, Director & Chair of the Reserves Committee	Daryl Gilbert, Director

March 5, 2025

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.