SURGE ENERGY INC

Annual Information Form

For the Year Ended December 31, 2021
Dated March 9, 2022

Table of Contents

Select Definitions 3
Abbreviations and Conversion 4
Non-IFRS Measures 5
Notes on Reserves Data and Other Oil and Natural Gas Information 5
Special Note Regarding Forward Looking Statements 8
Surge Energy Inc. 11
Development of the Business 11
Description of the Business 12
Principal Producing Properties 14
Statement of Reserves Data 17
Description of Capital Structure 26
Dividend Policy 28
Market for Securities 29
Directors and Officers 30
Audit Committee 34
Industry Conditions 37
Risk Factors 62
Legal Proceedings And Regulatory Actions 77
Interest of Management and Others in Material Transactions 78
Auditor, Transfer Agent and Registrar 78
Interest of Experts 78
Additional Information 78

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 herein, but not defined herein, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

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

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

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

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

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

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

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

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

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

"**Debentures**" means, collectively, the Initial Debentures and the Series 2 Debentures, as more particularly described under the heading "*Description of Capital Structure*";

"**First Lien Credit Facilities**" means the aggregate $150 million revolving first lien secured credit facilities of the Corporation with a syndicate of lenders;

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

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

"**Initial Debentures**" means the 5.75% convertible unsecured subordinated debentures due on December 31, 2022;

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

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

"**Reserves Report**" means the independent engineering report with a preparation date of February 23, 2022 and effective December 31, 2021 prepared by and containing the evaluation of Sproule of the oil, NGL and natural gas reserves attributable to the properties of the Corporation;

"**Second Lien Term Debt Facility**" means the $130 million non-revolving second lien secured credit facility of the Corporation with a syndicate of lenders;

"**Series 2 Debentures**" means the 6.75% convertible unsecured subordinated debentures due on June 30, 2024;

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

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

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

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

ABBREVIATIONS AND CONVERSION

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

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	Barrel	Mcf	thousand cubic feet
bbls	Barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
bbl/d	barrels per day	Bcf	billion cubic feet
NGLs	natural gas liquids	GJ	gigajoule
stb	stock tank barrel		

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

To Convert From	**To**	**Multiply By**
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

Other

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 35.1° API or greater is generally referred to as light crude oil. Liquid petroleum with a specified gravity of 25.8° to 35° API or greater is generally referred to as medium crude oil. Liquid petroleum with a specified gravity of 25.7° API or lower is generally referred to as heavy crude oil.
boe	barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
boe/d	barrel of oil equivalent per day
m^3	cubic metres
Mboe	1,000 barrels of oil equivalent
MMboe	1,000,000 barrels of oil equivalent
$000s	thousands of dollars
M$ or $M	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NON-IFRS MEASURES

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

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

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

The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The

estimated future net revenue from the production of the Corporation's natural gas and petroleum reserves does not represent the fair market value of the Corporation's reserves.

Caution Respecting Boe

In this AIF, the abbreviation boe means barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas when converting natural gas to boes. **Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

Definitions

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

Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates as follows:

"**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

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

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

"**developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing as follows:

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

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

“**undeveloped reserves**” are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves’ classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Interests in Reserves, Production, Wells and Properties

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

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

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

Description of Exploration and Development Wells and Costs

“**development costs**” means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves; (ii) drill, complete and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (iii) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide improved recovery systems.

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

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (i) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (ii) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (iii) dry hole contributions and bottom hole contributions; (iv) costs of drilling, completing and equipping exploratory wells; and (v) costs of drilling exploratory type stratigraphic test wells.

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

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

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

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

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

- the performance characteristics of the Corporation's oil and natural gas properties;
- oil and natural gas production levels, and expectations of future production rates, volumes and product mixes;
- the size of the oil and natural gas reserves of the Corporation and anticipated future cash flows from such reserves;
- projections of market prices and costs, and exchange and inflation rates;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- the Corporation's dividend policy;
- treatment under governmental regulatory regimes and tax and royalty laws;
- criteria and considerations in participations and acquisitions;

- the Corporation's tax horizon;
- timing of development of undeveloped reserves;
- estimated abandonment and reclamation costs and the timing thereof;
- expected land expiries and plans with respect thereto;
- plans to implement enhanced recovery; and
- capital expenditure programs, the allocation of such capital and the timing thereof.

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

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

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

- the impact pandemics and public health emergencies, including those related to COVID-19 coronavirus;
- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves and production levels;
- uncertainty surrounding the amount that will be available under the Credit Facilities in the future;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- failure to obtain industry partner 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;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- unfavourable weather conditions;

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

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

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

SURGE ENERGY INC.

Corporate Structure

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

The head office of the Corporation is located at 2100, 635 – 8th Avenue S.W., Calgary, Alberta T2P 3M3. 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" and the Initial Debentures and Series 2 Debentures are listed on the TSX under the symbols "SGY.DB" and "SGY.DB.A", respectively.

Three Year History

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

Year ended December 31, 2019

On March 28, 2019, Surge completed the sale of certain non-core assets in Northwest Alberta for aggregate cash proceeds of $28.1 million.

On June 28, 2019, Surge disposed of a 1.7 percent gross overriding royalty on total revenue from the Corporation's Southwest Saskatchewan, Southeast Alberta and North Central Alberta assets, for aggregate cash proceeds of $29.1 million.

On August 13, 2019, Surge completed an acquisition of a gas processing facility in its core Sparky area of Southeast Alberta for a purchase price of $12.1 million.

Year ended December 31, 2020

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

Year Ended December 31, 2021

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

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

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

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

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, 2021.

DESCRIPTION OF THE BUSINESS

Overview

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

Corporate Strategy

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

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

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

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

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

Competition

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

Cyclical and Seasonal Nature of Industry

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

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

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

Environmental Regulation

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

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, 2021, the Corporation has recorded an asset retirement obligation of $307.5 million. The Corporation anticipates that the expenditures necessary to satisfy the asset retirement obligation will be incurred over a period of twenty years, with the majority of the expenditures being incurred from years 2021 to 2041. 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. See also "*Interest of Management and Others in Material Transactions*".

The Corporation also has a hedging policy 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, 2021, see the Corporation's audited annual financial statements for the year ended December 31, 2021, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Fixed Price Hedging*".

Personnel

As at December 31, 2021, the Corporation had 70 head office employees and 6 field employees.

Health, Safety and Environmental

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

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

In 2021 Surge continued its commitment to environmental, social and governance spending initiatives by spending an aggregate of $12.6 million on abandonment activities.

PRINCIPAL PRODUCING PROPERTIES

The Corporation's principal oil and natural gas producing properties are located in Alberta and Saskatchewan and are focused across five core areas: Sparky, SE Saskatchewan, Manitoba, Carbonates, Valhalla, Shaunavon and Minors. A description of those properties, as at December 31, 2021, is provided below.

See "Development of the Business – Three Year History – Events Subsequent to December 31, 2021"

Sparky

As at December 31, 2021, Surge's principal properties in the Sparky area included the Sparky assets and the Lloyd/Cummings zone waterflood at Silver. At Sparky, Surge held an average working interest of approximately 90 percent in approximately 59,655 gross (53,977 net) developed acres and an average working interest of approximately 98 percent in approximately 47,398 gross (46,262 net) undeveloped acres. As at December 31, 2021, the Corporation held interests in 424 gross (339 net) oil wells and 6 gross (5 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 2021 production in Sparky was approximately 8,500 boe/d (89 percent oil and NGLs).

Sparky

The Sparky assets are comprised of five main fields spread between Provost and Wainwright in eastern Alberta and western Saskatchewan. Provost and Betty Lake are early stage primary development properties, while Wainwright, Macklin, Lakeview, and East Sounding are more mature, mostly developed waterflood assets. Production from the Sparky assets is primarily crude oil (89 percent oil and NGLs) ranging from 23° to 28° API.

In 2021, the Corporation drilled 44 gross (44 net) horizontal Sparky oil wells. Of these wells, 39 were on production by year-end 2021 and the remaining wells came on production in Q1 2022.

SE Saskatchewan

As at December 31, 2021, the Corporation's principal properties in the SE Saskatchewan area included Viewfield, Minard, Steelman, Pinto, Bryant and Gainsborough.

These SE Saskatchewan properties are primarily located in the South East corner of the Province. As at December 31, 2021, these operated properties included an average working interest of approximately 81 percent in approximately 38,071 gross (30,978 net) developed acres and an average working interest of approximately 84 percent in 30,072 gross (25,201 net) undeveloped acres. As at December 31, 2021, the Corporation held interests in 198 gross (153 net) oil wells producing in the Midale Subcrop, Frobisher Subcrop, and Alida Subcrop formations. The Corporation's production from this property is weighted 90 percent to light crude oil (greater than 31.1° API) and 10 percent to medium crude oil (22.3° to 31.1° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. This property's fourth quarter 2021 production was approximately 4,100 boe/d (91 percent oil).

In 2021, the Corporation drilled 3 gross (2.5 net) horizontal, Frobisher oil wells. These wells all came on production in Q1 2022.

Manitoba

As at December 31, 2021, the Corporation's principal properties in the Manitoba area included Sinclair.

The Manitoba properties are primarily located approximately 290 kilometres west of Brandon, Manitoba and east of the Saskatchewan border. As at December 31, 2021, these operated properties included an average working interest of approximately 73 percent in approximately 8,958 gross (6,575 net) developed acres and an average working interest of approximately 79 percent in 4,422 gross (3,473 net) undeveloped acres. As at December 31, 2021, the Corporation held interests in 121 gross (90 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 2021 production was approximately 630 boe/d (100 percent oil).

Carbonates

As at December 31, 2021, Carbonates consists of the Company's Greater Sawn, Nevis, and Westerose properties. The Corporation's principal properties in the Greater Sawn area included Sawn Lake, Otter and Red Earth (which collectively comprise the Greater Sawn Lake assets). Within Carbonates, Surge held an average working interest of approximately 84 percent in approximately 123,884 gross (103,778 net) developed acres and an average working interest of approximately 83 percent in approximately 68,031 gross (56,161 net) undeveloped acres. As at December 31, 2021, the Corporation held interests in 362 gross (300 net) oil wells and 20 gross (14 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 2021 production in Carbonates was approximately 3,400 boe/d (90 percent oil and NGLs).

Greater Sawn Lake

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

Valhalla

As at December 31, 2021, the Corporation's principal property in the Valhalla area is the Valhalla/Wembley property. At Valhalla, Surge held an average working interest of approximately 70 percent in approximately 22,920 gross (16,032 net) developed acres and an average working interest of approximately 72 percent in approximately 10,680 gross (7,728 net) undeveloped acres. As at December 31, 2021, the Corporation held interests in 100 gross (59 net) oil wells and 9 gross (4 net) gas wells producing from formations including, but not limited to, Doig and Montney. In addition, the Corporation operates multiple oil batteries providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2021 production in Valhalla was approximately 2,600 boe/d (50 percent oil and NGLs).

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

In 2021, the Corporation drilled 1 gross (1 net) horizontal, multi-frac, Montney oil well. This well was on production by December 31, 2021.

Shaunavon

The Shaunavon properties are primarily located approximately 100 kilometres southwest of Swift Current, Saskatchewan and 140 kilometres east of the Alberta border. As at December 31, 2021, these operated properties included an average working interest of approximately 98 percent in approximately 24,249 gross (23,828 net) developed acres and an average working interest of approximately 100 percent in 12,021 gross (12,021 net) undeveloped acres. As at December 31, 2021, the Corporation held interests in 185 gross (185 net) oil wells producing from the Upper and Lower Shaunavon formations, among others. The Corporation's production from this property is weighted 90 percent to medium crude oil (21° to 26° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. This property's fourth quarter 2021 production was approximately 1,300 boe/d (90 percent oil).

Minors

As at December 31, 2021, 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

63 percent in approximately 154,666 gross (97,130 net) developed acres and an average working interest of approximately 69 percent in approximately 45,983 gross (31,776 net) undeveloped acres. As at December 31, 2021, the Corporation held interests in 224 gross (187 net) oil wells and 121 gross (27 net) gas wells. This area's fourth quarter 2021 production was approximately 400 boe/d (66 percent oil and NGLs).

STATEMENT OF RESERVES DATA

In accordance with NI 51-101, Sproule prepared the Reserves Report based on its evaluation of the oil, NGL and natural gas reserves attributable to the properties of the Corporation as at December 31, 2021. The Reserves Report has a preparation date of February 23, 2022.

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	19,977	8,318	1,495	31,434	255	17,455	7,525	1,225	28,462	223
Developed Non-Producing	614	973	127	2,009	-	551	865	103	1,787	-
Undeveloped	17,426	11,128	1,680	34,846	-	15,128	10,061	1,430	31,958	-
Total Proved	38,017	20,419	3,302	68,289	255	33,134	18,451	2,757	62,207	223
Probable	15,981	9,920	1,455	29,209	73	13,491	8,632	1,209	26,309	66
Total Proved plus Probable	53,998	30,338	4,757	97,498	327	46,625	27,082	3,966	88,516	289

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

($M)	Before Future Income Tax Expenses and Discounted at 0%	5%	10%	15%	20%
Proved					
Developed Producing	620,512	673,962	623,371	568,815	522,154
Developed Non-Producing	63,850	49,849	40,884	34,753	30,330
Undeveloped	843,557	630,245	484,739	382,767	309,031
Total Proved	1,527,919	1,354,056	1,148,993	986,335	861,516
Probable	1,123,995	793,198	594,691	466,925	379,698
Total Proved plus Probable	2,651,914	2,147,254	1,743,684	1,453,260	1,241,214

($M)	After Future Income Tax Expenses and Discounted at 0%	5%	10%	15%	20%
Proved					
Developed Producing	620,512	673,962	623,371	568,815	522,154
Developed Non-Producing	63,850	49,849	40,884	34,753	30,330
Undeveloped	735,479	553,195	428,128	340,112	276,201
Total Proved	1,419,841	1,277,006	1,092,383	943,680	828,686
Probable	862,683	605,912	453,978	357,374	292,053
Total Proved plus Probable	2,282,524	1,882,917	1,546,361	1,301,054	1,120,739

	Unit Value before Income Tax Discounted at 10%/year ($/boe)
Proved	
Developed Producing	20.12
Developed Non-Producing	22.50
Undeveloped	15.17
Total Proved	17.75
Probable	21.45
Total Proved plus Probable	18.86

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

(Undiscounted) ($M)	Revenue	Royalties	Operating Costs	Develop-ment Costs	Abandon-ment and Other Costs	Future net revenue before income taxes	Future income taxes	Future net revenue after income taxes
Total Proved	4,987,257	590,947	1,895,106	670,163	303,122	1,527,919	108,078	1,419,841
Total Proved plus Probable	7,307,216	926,455	2,580,486	831,997	316,364	2,651,914	369,391	2,282,524

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)	725,308	16.76
Heavy Crude Oil(1)	420,013	19.91
Conventional Natural Gas(2)	3,549	10.82
Coalbed Methane(2)	124	3.32
Proved plus Probable		
Light and Medium Crude Oil(1)	1,110,815	18.16
Heavy Crude Oil(1)	628,763	20.37
Conventional Natural Gas(2)	3,969	10.01
Coalbed Methane(2)	137	2.84

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, 2021 in its evaluation in estimating reserves data using forecast prices and costs. The weighted average historical prices received by the Corporation for 2021 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)
2021 (Historic)	80.31	68.73	3.64	85.88	51.64	43.39	3.3%	6.6%	0.80
2022	86.25	75.63	3.88	91.25	54.75	38.64	0.0%	0.0%	0.80
2023	82.40	71.56	3.36	87.50	50.75	36.05	2.0%	2.0%	0.80
2024	79.80	68.74	3.02	85.00	49.30	34.68	2.0%	2.0%	0.80
2025	81.39	70.12	3.08	86.70	50.29	35.37	2.0%	2.0%	0.80
2026	83.02	71.52	3.14	88.43	51.29	36.08	2.0%	2.0%	0.80
2027	84.68	72.95	3.21	90.20	52.32	36.80	2.0%	2.0%	0.80
2028	86.38	74.41	3.27	92.01	53.36	37.53	2.0%	2.0%	0.80
2029	88.10	75.90	3.34	93.85	54.43	38.28	2.0%	2.0%	0.80
2030	89.87	77.42	3.40	95.72	55.52	39.05	2.0%	2.0%	0.80
2031	91.66	78.96	3.47	97.64	56.63	39.83	2.0%	2.0%	0.80
2032	93.50	80.54	3.54	99.59	57.76	40.63	2.0%	2.0%	0.80

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

Reconciliation of Changes in Reserves

The following table sets forth a combined reconciliation of the Corporation's gross reserves as at December 31, 2021, derived from the Reserves Report using forecast prices and cost estimates, reconciled to the gross reserves of the Corporation as at December 31, 2021.

	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, 2020	38,770	16,552	1,968	58,240	741	67,120
Product Type Transfer						-
Extensions and Improved Recovery	244	294	7	384		609
Infill Drilling	762	2,018	53	3,357		3,394
Technical Revisions	(2,851)	735	487	7,227	(585)	(521)
Acquisitions	10,342	286	961	7,066		12,767
Dispositions	(9,739)		(152)	(7,315)		(11,111)
Economic Factors	4,175	2,060	196	5,293	183	7,343
Production	(3,687)	(1,526)	(219)	(5,963)	(85)	(6,439)
Balance at December 31, 2021	38,017	20,419	3,302	68,289	255	73,161

	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, 2020	20,912	7,903	861	27,002	182	34,207
Product Type Transfer	-	-	-	-	-	-
Extensions and Improved Recovery	735	232	18	962	-	1,146
Infill Drilling	299	590	14	866	-	1,047
Technical Revisions	(960)	324	100	439	(164)	(490)
Acquisitions	4,953	912	535	4,344	-	7,123
Dispositions	(8,418)	-	(103)	(4,814)	-	(9,323)
Economic Factors	(1,540)	(41)	29	412	55	(1,474)
Production	-	-	-	-	-	-
Balance at December 31, 2021	15,981	9,919	1,455	29,209	73	32,236

	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, 2020	59,682	24,455	2,829	85,243	924	101,327
Product Type Transfer						-
Extensions and Improved Recovery	979	526	26	1,345		1,755
Infill Drilling	1,062	2,608	67	4,223		4,441
Technical Revisions	(3,811)	1,059	587	7,666	(749)	(1,012)
Acquisitions	15,295	1,197	1,496	11,410		19,890
Dispositions	(18,157)		(255)	(12,130)		(20,433)
Economic Factors	2,635	2,019	225	5,705	238	5,869
Production	(3,687)	(1,526)	(219)	(5,963)	(85)	(6,439)
Balance at December 31, 2021	53,998	30,338.1	4,757	97,500	327	105,397

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				
2019	4,389	1,685	105	5,434
2020	674	795	21	1,587
2021	5,576	2,529	472	3,541

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				
2019	3,770	1,290	84	1,308
2020	537	673	20	1,435
2021	4,037	1,720	324	3,541

Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

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

Significant Factors or Uncertainties Affecting Reserves Data

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

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

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

Future Development Costs

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

	Forecast Prices and Costs	
	Proved Reserves ($M)	Proved plus Probable Reserves ($M)
2022	110,520	122,445
2023	153,887	158,190
2024	164,790	170,058
2025	137,424	191,119
2026	63,253	128,914
Remaining Years	40,290	61,271
Total Undiscounted	670,163	831,997

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

Other Oil and Gas Information

Oil and Gas Wells

The following table sets forth the number and status of the Corporation's wells effective December 31, 2021.

	Producing								Non-Producing							
	Oil		Natural Gas		Coalbed Methane		Water Inj/Disp		Oil		Natural Gas		Coalbed Methane		Water Inj/Disp	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,143	890	64	28	7	4	293	206	1,954	1,621	405	306	1	1	280	228
Saskatchewan	463	405	77	5	-	-	52	42	380	176	16	8	-	-	63	13
Manitoba	144	112	-	-	-	-	5	5	10	9	-	-	-	-	-	-
BC	-	-	1	1	-	-	-	-	1	0	-	-	-	-	-	-
Total	1,750	1,408	142	33	7	4	350	253	2,345	1,807	421	315	1	1	343	241

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2021, 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	134,004	107,043	2,826
Saskatchewan	64,807	56,732	16,373
Manitoba	4,262	3,313	2,233
BC	-	-	-
Total	203,073	167,088	21,432

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation typically estimates well abandonment costs area by area. Such costs are included in the Reserves Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the Reserves Report for 4,062 net wells under the proved reserves category is $303.1 million undiscounted ($59.5 million discounted at 10 percent), of which a total of $17.3 million is estimated to be incurred in 2023, 2024 and 2025. This estimate includes expected reclamation costs for surface leases which have existing wells with economic developed reserves assigned or future development drilling locations. The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Subject to pending changes in applicable regulations regarding the abandonment and reclamation, ongoing environmental obligations are expected to be funded out of cash flow.

Forward Contracts

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

For details of the Corporation's forward contracts in place as at December 31, 2021, see the Corporation's audited annual financial statements for the year ended December 31, 2021, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Fixed Price Hedging*".

Tax Horizon

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

Costs Incurred

The following table summarizes capital expenditures incurred by the Corporation during the year ended December 31, 2021.

	Property Acquisition Costs				
	Proved Properties	**Unproved Properties**	**Property Dispositions**	**Exploration Costs**	**Development Costs**
Total ($M)			64,745		103,786

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, 2021.

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	47.00	46.50
Heavy Crude Oil	-	-	-	-
Conventional Natural Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
Total	-	-	47.00	46.50

Planned Capital Expenditures

The Corporation has announced a planned capital expenditure budget of approximately $124 million for 2022.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Reserves Report for 2021 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	3,224	-	1,713	233	123	3,671	15%
Valhalla	1,955	-	11,101	-	483	4,288	18%
Sparky	3,880	4,002	5,903	-	98	8,963	37%
Shaunavon	-	1,048	864	-	26	1,218	5%
SE Saskatchewan	3,630	-	3,910	-	579	4,860	20%
Manitoba	738	-	-	-	-	738	3%
Minors	113	69	579	-	24	304	1%
Total Proved	13,540	5,120	24,070	233	1,332	24,042	100%
Proved Plus Probable							
Carbonates	3,401	-	1,778	237	132	3,868	14%
Valhalla	2,154	-	12,196	-	531	4,717	18%
Sparky	4,358	4,488	6,531	-	110	10,044	37%
Shaunavon	-	1,094	904	-	27	1,272	5%
SE Saskatchewan	4,274	-	4,716	-	706	5,766	22%
Manitoba	815	-	-	-	-	815	3%
Minors	125	72	597	-	25	321	1%
Total Proved Plus Probable	15,127	5,654	26,721	237	1,530	26,803	100%

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2021, 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, 2021	**Jun 30, 2021**	**Sep 30, 2021**	**Dec 31, 2021**
Conventional Natural Gas (Mcf/d)	15,191	14,208	16,609	19,294
Light and Medium Crude Oil (bbls/d)	13,422	12,202	14,264	17,192
NGL (bbls/d)	583	521	575	720
Coalbed Methane (Mcf/d)	271	248	206	209
Total (boe/d)	16,582	15,132	17,642	21,163

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

	Three Months Ended			
($ per Bbl)	**Mar 31, 2021**	**Jun 30, 2021**	**Sep 30, 2021**	**Dec 31, 2021**
Prices Received	53.02	58.40	64.20	72.86
Royalties Paid	(5.69)	(8.04)	(9.53)	(11.99)
Production Costs	(18.05)	(17.85)	(16.74)	(16.78)
Transportation Costs	(1.03)	(0.94)	(1.11)	(1.27)
Operating Netback[(1)]	28.25	31.57	36.83	42.82

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, 2021**	**Jun 30, 2021**	**Sep 30, 2021**	**Dec 31, 2021**
Prices Received	6.32	2.01	3.34	4.75
Royalties Received	0.08	0.00	(0.14)	(0.24)
Production Costs	(0.26)	(0.12)	(0.55)	(0.76)
Transportation Costs	(0.00)	(0.00)	(0.00)	(0.00)
Operating Netback	6.13	1.90	2.66	3.75

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

	Three Months Ended			
($ per boe)	**Mar 31, 2021**	**Jun 30, 2021**	**Sep 30, 2021**	**Dec 31, 2021**
Prices Received	54.07	58.74	64.76	73.65
Royalties Paid	(5.68)	(8.04)	(9.55)	(12.03)
Production Costs	(18.09)	(17.87)	(16.83)	(16.91)
Transportation Costs	(1.03)	(0.94)	(1.11)	(1.27)
Operating Netback[(1)]	29.27	31.89	37.27	43.44

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, 2021.

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	3,199	1,932	120	-	3,640	21%
Valhalla	1,192	7,862	288	-	2,790	16%
Sparky	6,491	4,747	77	-	7,359	42%
Shaunavon	1,177	203	5	-	1,216	7%
Minors	194	453	21	233	329	2%
SE Saskatchewan	1,268	807	82	-	1,485	8%
Manitoba	244	2	-	-	244	1%
Sold Properties	516	332	9	-	580	3%
Total	14,280	16,337	600	233	17,642	100%

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series.

Common Shares

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

Preferred Shares

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

Debentures

The Debentures, including the Initial Debentures and the Series 2 Debentures, are issued under and pursuant to the provisions of the Indenture among Computershare Trust Company of Canada and Surge. The following is a summary of the material attributes and characteristics of the Debentures. This summary does not purport to be complete and is subject to and qualified in its entirety by reference to the terms of the Indenture which may be viewed under Surge's profile on SEDAR at www.sedar.com.

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

Initial Debentures

The Initial Debentures will mature and be repayable on December 31, 2022 (the "**Initial Debenture Maturity Date**") and will accrue interest at the rate of 5.75% per annum payable semi-annually in arrears on December 31 and June 30 of each year (each an "**Initial Debenture Interest Payment Date**"), commencing on June 30, 2018 and computed on the basis of a 365-day year. Interest on the Initial Debentures will be payable in lawful money of Canada.

At the holder's option, the Initial Debentures may be converted into Common Shares at any time prior to 5:00 p.m. (Calgary time) on the earlier of the business day immediately preceding (i) the Initial Debenture Maturity Date; and (ii) if called for redemption, the date fixed for redemption by the Corporation. The conversion price of the Initial Debentures has been adjusted following the completion of the Consolidation to $23.22923 per Common Share, which conversion price includes certain additional adjustments required as a result of dividends declared and paid on the Common Shares in each Applicable Period (as defined in the Indenture) pursuant to section 6.5(e) of the Indenture, subject to further adjustment on certain events (the "**Initial Debenture Conversion Price**"). This represents a conversion rate of approximately 43.0492 Common Shares for each $1,000 principal amount of Initial Debentures, subject to certain anti-dilution provisions. Holders who convert their Initial 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 Initial Debenture Interest Payment Date. If a holder elects to convert its Debentures in connection with a change of control that occurs prior to the Initial Debenture Maturity Date, the holder will be entitled to receive additional Common Shares as a make-whole premium on conversion in certain circumstances (as more fully described in the Indenture).

On or after December 31, 2021 and prior to the Initial Debenture Maturity Date, the Initial Debentures may be redeemed by the Corporation, in whole or in part, from time to time, on not more than 60 days and not less than 30 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption.

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

Series 2 Debentures

The Series 2 Debentures will mature and be repayable on June 30, 2024 (the "**Series 2 Debenture Maturity Date**") and will accrue interest at the rate of 6.75% per annum payable semi-annually in arrears on December 31 and June 30 of each year (each a "**Series 2 Debenture Interest Payment Date**"), commencing on December 31, 2019 and computed on the basis of a 365-day year. Interest on the Series 2 Debentures will be payable in lawful money of Canada.

At the holder's option, the Series 2 Debentures may be converted into Common Shares at any time prior to 5:00 p.m. (Calgary time) on the earlier of the business day immediately preceding (i) the Series 2 Debenture Maturity Date; and (ii) if called for redemption, the date fixed for redemption by the Corporation. The conversion price of the Series 2 Debentures has been adjusted following the Consolidation to $19.125 per Common Share, subject to further adjustment on certain events (the "**Series 2 Debenture Conversion Price**"). This represents a conversion rate of approximately 52.2876 Common Shares for each $1,000 principal amount of Series 2 Debentures, subject to certain anti-dilution provisions. Holders who convert their Series 2 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 Series 2 Debenture Interest Payment Date. If a holder elects to convert its Series

2 Debentures in connection with a change of control that occurs prior to the Series 2 Debenture Maturity Date, the holder will be entitled to receive additional Common Shares as a make-whole premium on conversion in certain circumstances (as more fully described in the Indenture).

The Series 2 Debentures may not be redeemed by the Corporation prior to June 30, 2022 except in certain circumstances following a change of control. On and after June 30, 2022 and prior to June 30, 2023, the Series 2 Debentures may be redeemed by the Corporation, in whole or in part, from time to time, on not more than 60 days and not less than 30 days prior written notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption, provided that the volume weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days prior to the date on which notice of redemption is provided is at least 125 percent of the Conversion Price. On or after June 30, 2023 and prior to the Series 2 Debenture Maturity Date, the Series 2 Debentures may be redeemed by the Corporation, in whole or in part, from time to time, on not more than 60 days and not less than 30 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption.

The Series 2 Debentures are listed and posted for trading on the TSX under the symbol “SGY.DB.A”.

DIVIDEND POLICY

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

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

	Dividends per Common Share ($)(1)		
Month	**2022**	**2021**	**2020**
January	-	-	0.008333
February	-	-	0.008333
March	-	-	0.000833
April	-	-	-
May	-	-	-
June	-	-	-
July	-	-	-
August	-	-	-
September	-	-	-
October	-	-	-
November	-	-	-
December	-	-	-
Total	**-**	**-**	**0.017499**

Note:

(1) Without giving effect to the Consolidation.

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

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

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "SGY". The following table sets forth the market price ranges and the trading volumes for the Common Shares for the periods indicated, as reported by the TSX, for the year ended December 31, 2021.

	Price Range ($)		
Period	**High(1)**	**Low(1)**	**Trading Volume(1)**
January	3.06	2.51	2,162,706
February	4.93	2.64	5,027,362
March	6.46	4.21	5,592,578
April	5.36	4.34	2,039,994
May	5.27	4.21	2,581,648
June	6.38	4.85	4,730,841
July	6.04	4.34	2,337,910
August	4.59	3.06	3,729,410
September	5.55	3.81	7,294,606
October	5.64	5.03	15,146,204
November	5.52	3.87	13,569,323
December	4.47	3.74	8,543,480

Note:

(1) Information is presented as though the Consolidation occurred on January 1, 2021.

The Initial Debentures are listed and posted for trading on the TSX under the trading symbol "SGY.DB". The following table sets forth the market price ranges and the trading volumes for the Initial Debentures for the periods indicated, as reported by the TSX, for the year ended December 31, 2021.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
January	72.00	62.50	2,900
February	82.00	69.00	8,100
March	90.00	76.00	9,230
April	91.99	80.01	5,080
May	95.49	85.04	6,470
June	96.75	92.50	4,860
July	97.50	95.00	4,330
August	97.25	92.01	7,140
September	98.96	94.48	14,160

Period	Price Range ($) High	Low	Trading Volume
October	99.00	97.15	8,740
November	99.56	96.00	10,430
December	100.00	96.61	12,000

The Series 2 Debentures are listed and posted for trading on the TSX under the trading symbol "SGY.DB.A". The following table sets forth the market price ranges and the trading volumes for the Series 2 Debentures for the periods indicated, as reported by the TSX, for the year ended December 31, 2021.

Period	Price Range ($) High	Low	Trading Volume
January	68.00	60.00	4,030
February	80.00	66.90	5,300
March	89.00	78.94	4,840
April	88.49	80.75	3,170
May	88.75	86.00	2,600
June	96.50	88.50	6,680
July	97.44	93.96	3,110
August	95.00	88.00	1,380
September	96.00	93.00	10,640
October	98.75	95.80	5,180
November	99.85	94.02	8,130
December	99.95	96.00	7,950

DIRECTORS AND OFFICERS

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

Name and Residence	Position	Principal Occupation During Previous Five Years
Paul Colborne Alberta, Canada	President and Chief Executive Officer Director since April 13, 2010	President and Chief Executive Officer of the Corporation. He is also the President of StarValley Oil and Gas Ltd., a private, Calgary-based oil and gas company. Mr. Colborne currently serves as Chairman of the board of directors of Rising Star Resources Ltd., a private 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 an oil and gas company called Startech Energy Ltd., a publicly traded company, which grew to 15,000 boe/d. 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 boe/d publicly traded energy trust. From 1996 to 2013, Mr. Colborne was on the board of directors of Crescent Point Energy Corp., a 110,000 boe/d publicly traded oil and gas company. Until its sale in 2009, Mr. Colborne served as Chairman of TriStar Oil & Gas Ltd. He was also previously a Director for Westfire Energy Ltd., Twin Butte Energy Ltd., Red River Oil Inc., Cequence Energy Ltd., and Chairman of Seaview Energy Ltd. Until its sale

Name and Residence	Position	Principal Occupation During Previous Five Years
		in 2009, Mr. Colborne served as a Director of Breaker Energy Ltd. Mr. Colborne was also Chairman and a Director of Mission Oil and Gas Inc. until its sale in 2007. In 2014, Paul stepped down from the board of Legacy Oil + Gas. In 2014, Paul completed his term as Chairman of a private company called New Star Energy Ltd., and stepped down as a Director.
James Pasieka Alberta, Canada	Director since April 13, 2010 Chairman of the Board since January 7, 2015	Counsel to the national law firm McCarthy Tétrault LLP since January 1, 2020. Prior thereto, partner at McCarthy Tétrault LLP since September 1, 2013. Prior to that, partner of the national law firm Heenan Blaikie LLP since January 1, 2001. Mr. Pasieka has served as an officer and director of a number of public energy companies, and chairman of the board of several oil and gas companies.
Marion Burnyeat ICD.D(2)(4) Alberta, Canada	Director since July 16, 2018	Director, Calgary Academy and Headwater Learning Group since June 2018. Prior thereto, Director, SECURE Energy Services from April 2020 to July 2021. Consultant with Inter Pipeline on mergers and acquisitions from April to June 2018. Vice President of Field Services at Westcoast Energy Inc. from January 2013 to March 2017. Prior thereto, Ms. Burnyeat served as Vice President of Midstream of Westcoast Energy Inc. from May 2008 to January 2013. She served as Vice President Strategic Development and Stakeholder Relations at Westcoast Energy Inc. from January 2007 to May 2008. Ms. Burnyeat has nearly thirty years in the energy sector primarily with Spectra Energy Corporation and its predecessor companies. She held increasingly responsible executive roles in leading Midstream business units, Strategic Development, Stakeholder Relations and Business Development. Ms. Burnyeat holds the ICD.D designation from the Institute of Corporate Directors, a Bachelor of Commerce degree from the University of Alberta and a Master of Business Administration degree from Edinburgh University, Scotland. She has held positions on not-for-profit boards and is an active volunteer for several charitable organizations including Freestyle Alberta.
Daryl Gilbert(2)(3) Alberta, Canada	Director since June 5, 2014	Chair of the Reserves Committee for the Corporation. Managing Director and Investment Committee member of Carbon Infrastructure Partners (formerly JOG Capital Inc.) since May 2008. Mr. Gilbert has also been an independent businessman and investor, and serves as a director for a number of public and private entities, since 2005. Mr. Gilbert has been active in the Western Canadian oil and natural gas sector for over 40 years, working in reserves evaluation with Gilbert Laustsen Jung Associates Ltd. (now GLJ Petroleum Consultants Ltd.) ("**GLJ**"), an engineering consulting firm, from 1979 to 2005. Mr. Gilbert served as President and Chief Executive Officer of GLJ from 1994 to 2005.
Michelle Gramatke(1) Alberta, Canada	Director since May 2019	Ms. Gramatke is a Chartered Accountant with over 25 years of financial experience. She has most recently acted as Chief Financial Officer of JOG Capital (a private equity investment firm based in Calgary) from 2004 until August 2020. Prior to her position with JOG Capital, Ms. Gramatke held several executive positions, including as Chief Financial Officer of PricewaterhouseCoopers Central Asia, Deputy Chief Financial Officer for an American NASDAQ-listed telecommunications company with operations in Russia and Manager with PricewaterhouseCoopers Moscow. Ms. Gramatke began her career with KPMG in Calgary focusing on Canadian upstream oil and gas, construction and mining companies.

Name and Residence	Position	Principal Occupation During Previous Five Years
Robert Leach[(1)(2)] Arizona, United States of America	Director since April 13, 2010	President of Sonoma Valley LLC Arizona Inc., a Phoenix based real estate investment company. Mr. Leach was formerly Chief Executive Officer of Custom Truck Sales Ltd., a private company operating Kenworth truck dealerships in Saskatchewan and Manitoba since 1986.
Allison Maher[(1)(3)] Alberta, Canada	Director since July 16, 2018	Chair of the Audit Committee. President, Director and Co-founder of Family Wealth Coach Planning Services since January 2009. Prior thereto, Ms. Maher worked at other financial-advisory and estate-planning companies such as Great-West Life (London Life) for a decade. Ms. Maher began her career at KPMG in the areas of Tax and Corporate Audit. Ms. Maher has her Certified Corporate Director, Chartered Professional Accountant, Certified Financial Planner, Trust and Estate Practitioner and Family Enterprise Advisor designations. Ms. Maher received her Bachelor of Commerce degree, with Distinction, from the University of Calgary. Ms. Maher is an active member of the Institute of Corporate Directors, Chair of TIGER21 Calgary and currently holds board positions on several not-for-profit boards.
P. Daniel O'Neil[(3)(4)] Alberta, Canada	Director since April 13, 2010	Chair of the Environment, Health and Safety Committee for the Corporation. Independent businessperson since his retirement on May 8, 2013. Prior thereto, Mr. O'Neil acted as President and Chief Executive Officer of the Corporation from April 13, 2010 until his retirement and as President and Chief Executive Officer of Breaker Energy Ltd., a publicly traded oil and natural gas company, from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009. Mr. O'Neil was also a director of Cathedral Energy Services Ltd. Prior to their sales, Mr. O'Neil was acted as a Director of Hyperion Exploration Corporation and Cequence Energy Ltd.
Murray Smith[(2)(4)] Alberta, Canada	Director since June 25, 2010	Chair of the Compensation, Nominating and Corporate Governance Committee for the Corporation. President of Murray Smith and Associates. Mr. Smith also serves on the board of two private companies and Williams Companies Inc. (WMB.nyse), a Tulsa based midstream company. Prior thereto, Mr. Smith acted as an Official Representative of the Province of Alberta to the United States of America until 2007. Prior thereto, Mr. Smith was a member of the Legislative Assembly in the Province of Alberta serving in four different Cabinet portfolios – Energy, Gaming, Labour, and Economic Development from 1993 to 2005.
Murray Bye Alberta, Canada	Chief Operating Officer	Chief Operating Officer of the Corporation since August 2018. Prior thereto, Mr. Bye acted as Vice President, Production of the Corporation from May 2013. Prior thereto, Mr. Bye was Asset Team Lead – West at Surge since June 2010. Prior to his role at Surge, Mr. Bye held a number of positions at EnCana Corporation between the years 2000 to 2010 including: Group Lead of Development, Exploitation Engineer, and Production Engineer. Mr. Bye received a Petroleum Engineering degree from Montana Tech.
Jared Ducs Alberta, Canada	Chief Financial Officer	Chief Financial Officer of the Corporation since August 2019. Prior thereto, Mr. Ducs has held several progressively more senior roles at the Corporation including Director of Corporate Development, Assistant Controller and Manager of Financial Reporting and, most recently, held the position of Vice President, Finance of the Corporation since August 2018. Preceding his role at the Corporation, Mr. Ducs was a senior member of the Finance group at Breaker Energy Ltd. prior to its sale to NAL Oil & Gas Trust in 2009. Prior

Name and Residence	Position	Principal Occupation During Previous Five Years
		thereto, Mr. Ducs was a senior associate with Ernst & Young LLP. Mr. Ducs holds a Charted Accountant Designation and received his Bachelor of Management in Accounting and Finance from the University of Lethbridge.
Derek Christie Alberta, Canada	Senior Vice President – Geosciences	Senior Vice President, Geosciences of the Corporation since November 2019. Prior thereto, Mr. Christie acted as the Senior Vice President of Exploration & Corporate Development at Crescent Point Energy and was previously employed with Crescent Point Energy in various Senior Management positions in exploration, geosciences and corporate development since February 2007.
Margaret Elekes Alberta, Canada	Senior Vice-President, Land and Business Development	Senior Vice-President, Land and Business Development of the Corporation since August 2018. Prior thereto, Ms. Elekes held the position of Vice-President, Land and Business Development of the Corporation from August 2016. Prior thereto and since April 2010, Ms. Elekes acted as Vice-President, Land of the Corporation at Surge. Prior thereto, Ms. Elekes acted as Consulting Landman for Breaker Energy from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009. Prior thereto, Ms. Elekes acted as Landman and US Land Manager for Upton Resources from December 1995 until its acquisition by StarPoint Energy in February 2004.

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

As at March 9, 2022, the directors and executive officers of the Corporation, as a group, beneficially own, control or direct, directly or indirectly, 2,289,781 Common Shares, representing approximately 2.7 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 Queen's Bench (the "**Court**") upon an application by LGX's senior lender. LGX's stock was cease traded shortly thereafter and a receiver manager was appointed. Mr. Gilbert was a director of Connacher Oil & Gas Limited ("**Connacher**") from October 2014 until February 2019. On May 17, 2016, Connacher applied for and was granted protection from its creditors by the Court pursuant to the *Companies' Creditors Arrangement Act* (Canada). On February 16, 2019, Connacher announced that it was proceeding to close on a credit bid transaction with its supporting lenders. Mr. Gilbert resigned from the Board shortly thereafter. Mr. Gilbert was a director of Trident Exploration Corp. ("**Trident**") from 2010 through year end 2018. On April 30, 2019, Trident announced it had ceased operations and had transferred all assets to the Alberta Energy Regulator. On May 3rd, 2019, PricewaterhouseCoopers LLP was appointed receiver.

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

Conflicts of Interest

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

AUDIT COMMITTEE

Composition of the Audit Committee, Charter and Review of Services

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

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

Name	**Independent**	**Financially Literate**	**Relevant Education and Experience**
Allison Maher	✓	✓	Ms. Maher is currently the President and Director of her own advisory firm, Family Wealth Coach Planning Services. She is highly involved in matters related to succession planning, as well as family governance, estate and risk management. Ms. Maher began her career with KPMG in the areas of Tax and Corporate Audit. Ms. Maher is presently a member of the Chartered Professional Accountants of Alberta, as well as an active member of the Institute of Corporate Directors, Chair of TIGER21 Calgary and currently holds board positions on several not-for-profit boards. Ms. Maher also holds Certified Corporate Director and Certified Financial Planner designations. Ms. Maher has been a member of the board of the Calgary Health Foundation since February 2020 and was a member of the board of the Heritage Park Foundation since June 2014 to June 2020. Ms. Maher has been a trustee for the Cidel Donor Advised Fund since June 2014. From May 2011 to May 2017, she served as chairperson and advisory board member for the Alberta Business Family Institute (University of Alberta). Ms. Maher holds a Bachelor of Commerce degree, with Distinction, from the University of Calgary.
Robert Leach	✓	✓	Mr. Leach is currently the President of Sonoma Valley LLC Arizona Inc., a Phoenix based real estate investment company. Mr. Leach was formerly the Chairman of the board of Breaker Energy Ltd. and holds a Bachelor of Commerce degree, majoring in accounting, from the University of Saskatchewan. Mr. Leach has experience reviewing and assessing financial statements from his tenure on the audit committee of Breaker, as a member of the Board of Surge, and through his years of experience at Custom Truck Sales Ltd. and International Fitness Holdings.
Michelle Gramatke	✓	✓	Ms. Gramatke was Chief Financial Officer and Chief Compliance Officer of JOG Capital, a Calgary based private equity investment fund advisor which invests in Canadian oil & gas companies from 2004 to August 2020. Ms. Gramatke was responsible for JOG Capital's financial reporting, treasury, tax and regulatory compliance.Ms. Gramatke is presently a member of the Chartered Professional Accountants of Alberta and holds a Bachelor of Management degree from the University of Lethbridge.

Pre-Approval of Policies and Procedures

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

External Auditor Service Fees

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

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

Year	Audit Fees[(1)]	Audit-Related Fees	Tax Fees[(2)]	All Other Fees
2021	$406,600	$nil	$123,553	$64,200
2020	$262,150	$nil	$54,300	$nil

Notes:

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

INDUSTRY CONDITIONS

Restrained Pipeline Capacity and Differential Volatility

Western Canada has seen significant growth in crude production volumes over recent years. This has resulted in pressure on the pipeline take-away capacity, leading to apportionment on the main lines and, in turn, backed-up local feeder pipelines. This has contributed to a widening of, and increased volatility in, the light oil pricing differential between WTI and Edmonton Par and the medium/heavy crude oil pricing differential between WTI and Cromer/WCS/Hardisty. Although pipeline expansions and optimizations are ongoing and producers are increasingly turning to rail as an alternative means of transportation, the lack of firm pipeline capacity continues to affect the oil and natural gas industry in Western Canada and limit the ability to produce and to market production. In addition, the pro-rationing of capacity on the interprovincial pipeline systems also continues to affect the ability to export oil and natural gas.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the Canada Energy Regulator ("**CER**") and the cabinet of the federal government. On August 28, 2019, Bill C-69 and related legislation came into force, creating a new regulatory regime pursuant to the Canadian Energy Regulator Act ("**CER Act**"); the *Canadian Navigable Waters Act*; and the *Impact Assessment Act* ("**IAA**"). The *CER Act* replaced the National Energy Board ("**NEB**") with the CER. The CER has similar oversight over federal energy infrastructure projects as the NEB had. However, approvals for projects which fall under the CER Act requiring an impact assessment will now be conducted by a review panel established under the IAA instead of the CER. The focus of the new CER Act and IAA is greater Indigenous and public participation as well as consideration for a broader range of impacts beyond just environmental impacts. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments as well as court challenges on various issues such as Indigenous title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory transition, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Western Canada to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects or their cancellation altogether.

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

After more than eight years, on September 29, 2021 Enbridge announced the completion of the 542 km Minnesota segment of the Line 3 Replacement. The Line 3 Replacement and Expansion's in-service date was October 1, 2021 and is expected to transport 760,000 barrels per day at full capacity. The Canadian portion of the pipeline began commercial operation on December 1, 2019. The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's Indigenous consultations. The Federal Court of Appeal quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following the Federal Court of Appeal's direction, Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision, including the environmental effects of project-related marine shipping. On February 22, 2019, the NEB delivered an updated report to Cabinet, recommending that Cabinet approve the pipeline expansion, subject to 156 conditions and 16 new recommendations, notwithstanding the fact that project-related marine shipping may have a significant adverse effect on the marine environment. On June 18, 2019, Cabinet approved the pipeline expansion, and on July 25, 2019, the NEB (now the CER) outlined how the regulatory process for the pipeline expansion would resume. Construction commenced on the Trans Mountain Pipeline in late 2019.

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

On January 16, 2020 the Supreme Court of Canada unanimously rejected British Columbia's appeal to regulate the flow of heavy oil in British Columbia. The Supreme Court found that interprovincial trade is federal jurisdiction and the flow of commodities such as heavy oil and bitumen should be overseen by federal regulators.

On April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the BC EMA) to impose a permitting requirement on carriers of heavy crude oil within British Columbia. On January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal.

Construction continued on the Trans Mountain Pipeline throughout 2020, however, the project was halted in December 2020 resuming in January 2021 with work commencing on the twinning of the existing 1,500 km line between Alberta to British Columbia and is expected to be in-service in late 2022.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, preconstruction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block certain permits and on April 15, 2020, a Montana judge ruled against the U.S. Army Corps of Engineers' use of a national permit for water crossings in the United States ("**Nationwide Permit 12**"). The United States Court of Appeals of the Ninth Circuit refused to stay the ruling. While the Supreme Court of the United States subsequently reinstated Nationwide Permit 12 in July 2020, it determined the reinstatement would not apply to the Keystone XL Pipeline. Construction commenced on the Alberta portion of the pipeline in summer of 2020.

The Alberta Government invested $1.5 billion in the Keystone XL Pipeline to accelerate construction in the hopes of having it operational by 2023. The investment by the Alberta Government included $1.5 billion in equity investment in 2020, followed by a $6 billion loan guarantee in 2021. On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States, following which the Biden administration revoked the permit 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 8, 2021, TC Energy Corporation ("**TC Energy**") terminated the Keystone XL Pipeline project.

Bill C-48, the *Oil Tanker Moratorium Act* (the "**OTMA**"), came into force on June 21, 2019. The OTMA imposes a moratorium on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tonnes from 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. The OTMA is subject to a review after five (5) years. See "*Industry Conditions –Environmental Regulation – Federal*".

The Government of Alberta has also sought to alleviate these transportation constraints by pursuing different transportation modalities and creating new markets. On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/d of crude oil out of the province. Following the Alberta provincial election on April 16, 2019, the new United Conservative Party ("**UCP**") Government announced that it was in negotiations to divest the rail contracts. On February 12, 2020, the Government of Alberta announced that it had sold off $10.6 billion in crude-by-rail contracts to the private sector. Following two train derailments which led to fires and oil spills in Saskatchewan, the federal government announced in February 2020, that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in early April 2020 and will remain in place until permanent rule changes are approved. As a result, trains subject to the order will be required to adhere to the reduced speed limits which were announced February 2020 within metropolitan areas, with further mandatory speed restrictions applying outside of metropolitan areas during winter months (November 15 to March 15). As of March 9, 2022, no permanent rules have been approved.

Natural gas prices in Alberta have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of LNG export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project**.**

In September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (the "**NGTL System**") to prioritize deliveries into storage ("**temporary service protocol**"). The change has served to somewhat stabilize supply and pricing, particularly during period of maintenance on the system. An expansion to the NGTL System was recommended for approval by the CER which was sent to the federal Cabinet for approval. Following the effects of COVID-19, the Governor in Council ("**GIC**") extended the legislative timeline for consultation with Indigenous groups which extended the decision date to no later than May 2021. On April 30, 2021, the GIC approved the issuance of the certificate of public convenience by the CER.

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

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

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

Legislation and Regulation

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and Saskatchewan, all of which should be carefully considered by investors in the oil and natural gas industry. It is not expected that any of these controls or regulations will affect the operations of Surge in a manner materially different than they would affect other oil and natural gas producers of similar size. All current legislation is a matter of public record and Surge is unable to predict what additional legislation or amendments may be enacted. Some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry are described further below.

Pricing and Marketing – Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the CER. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the CER and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the CER and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the CER and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to a CER order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the CER and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations. Natural gas prices in Alberta have been constrained in recent years due to increasing supply in North America, limited access to markets and limited storage capacity.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate an 8.7 percent short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the *Curtailment Rules*, the Government of Alberta will, on a monthly basis, direct oil producers producing more than 10,000 bbl/d to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The first curtailment order took effect on January 1, 2019 limiting province-wide production of crude oil and crude bitumen to 3.56 million bbl/d—a reduction of approximately 8.7 percent from the total daily average oil production in Alberta during December 2018. As a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage, the Government of Alberta announced on January 30, 2019, that it would ease the mandatory production curtailment beginning February 1, 2019, increasing the allowable production cap by 75,000 bbl/d to a maximum output of approximately 3.63 million bbl/d.

Surge was previously subject to a curtailment order. The Curtailment Rules which were set to be repealed on December 31, 2020, were extended through to December 31, 2021. In December 2020, the Government put monthly oil production limits into effect only if market conditions made it absolutely necessary. Industry was therefore free to produce at their discretion. On December 9, 2021, the Government of Alberta announced that the provincial policy on restraining production, a strategy to reduce price-depressing gluts, would end December 31, 2021.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994 and was replaced on November 30, 2018 when Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United

States Mexico Canada Agreement ("**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement. The USMCA came into force on July 1, 2020 following ratification by Mexico's senate in June 2019, the United States' House of Representatives and Senate on December 2019 and January 2020, respectively and by Canada on January 29, 2020. 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, the effects of the USMCA could have an impact on Western Canada's petroleum and natural gas industry at large, including the Corporation's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevented Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced.

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

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA has not received full ratification by national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's official departure from the European Union on January 31, 2020, CETA ceased to apply to Canada-United Kingdom Trade on January 1, 2021. The *Canada-United Kingdom Trade Continuity Agreement* (the "**CUKTCA**") replicates the CETA on a bilateral basis and is meant to maintain the status quo of in the Canada-United Kingdom trade relationship. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

Canada and ten other countries have agreed on the text of the *Comprehensive and Progressive Agreement for Trans-Pacific Partnership* ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam, and Singapore. While it is uncertain what effect CETA, CUKTA, CPTPP, or any other trade agreements will have on the petroleum and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

Extractive Sector Transparency Measures Act

The *Extractive Sector Transparency Measures Act* ("**ESTMA**"), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state owned entities, including employees and public office holders, made Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Failure to comply with the reporting obligations under ESTMA are punishable upon summary conviction with a fine of up to $250,000. In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over $9,000,000 in total liability.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas, natural gas liquids and sulphur production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Operations not on Crown lands and subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

From time to time the governments of the Western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry and may be introduced when commodity prices are low to encourage exploration and development activity.

In addition, the federal government may from time to time provide incentives to the oil and gas industry. In November 2018, the federal government announced its plans to implement an accelerated investment incentive, which provides oil and gas businesses with eligible Canadian development expenses and Canadian oil and gas property expenses with a first year deduction of one and a half times the deduction that is otherwise available. The federal government also announced in late 2018 that it will make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for crude oil and natural gas projects related to economic diversification as well as direct funding for clean growth crude oil and natural gas projects.

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

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced from Crown Lands. Producers of oil and natural gas from Crown lands in Alberta are also required to pay a royalty on substances produced from Crown lands.

On May 27, 2010, the Government of Alberta announced changes to the existing royalty framework under the *Petroleum Royalty Regulation, 2009* and the *Natural Gas Royalty Regulation, 2009* which became effective January 1, 2011 (the "**Alberta Royalty Framework**"). Changes included making the Natural Gas Deep Drilling Program, which adjusts the royalties for deep gas wells, a permanent initiative under the Alberta Royalty Framework. Qualifying wells under the Natural Gas Deep Drilling Program include natural gas wells with gas-oil ratios of greater than 1,800:1 which have been spud or deepened on or after May 1, 2010 and have a true vertical depth greater than 2,000 metres. At this time, an Emerging Resources and Technologies Initiative was also created to encourage new exploration and development from higher cost and more technically challenging resources, such as shale gas, coal seams and horizontal oil and gas wells. In particular, pursuant to the Emerging Resource and Technologies Initiative: (a) coalbed methane wells receive a maximum royalty rate of 5 percent for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010; (b) shale gas wells receive a maximum royalty rate of 5 percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010; (c) horizontal gas wells receive a maximum royalty rate of 5 percent for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and (d) horizontal oil wells and horizontal non-project oil sands wells receive a maximum royalty rate of 5 percent with volume and production month limits set according to the depth (including the horizontal distance) of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

On January 29, 2016, the Alberta government announced changes to the Alberta Royalty Framework. Under the modern royalty framework (the "**MRF**"), the sliding scale royalty concept was maintained, but is achieved with a greater deal of simplicity. The new royalty percentage is applied to the gross revenue generated from all hydrocarbons, with no differentiation between produced substances, and wells are charged a flat 5 percent royalty rate until revenues exceed a normalized well cost allowance, which is based on vertical well depth and lateral length. The calculation of this cost allowance, and other details regarding the various parameters within the new formula under the MRF was announced in 2016 and was fully implemented as of January 1, 2017. The former Alberta Royalty Framework continues to apply to any wells drilled prior to January 1, 2017, and thereafter for a period of 10 years following which, such wells will be transitioned into the MRF. As of January 1, 2027, older wells will become subject to the MRF.

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

Producers under the MRF, initially pay a flat rate of 5 percent of gross revenue from each well that is subject to the MRF until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5 percent and 40 percent for crude oil and pentanes and 5 percent and 36 percent for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Alberta Royalty Framework, the post-payout royalty rate under the MRF varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5 percent as the mature well's production declines. As the MRF 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.

In addition to any negotiated royalty amount payable to the freehold mineral owner, producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4 percent of revenues reported from fee simple mineral title properties.

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

Subject to certain available incentives, royalty rates for conventional crude oil production subject to the Alberta Royalty Framework range from a base rate of 0 percent to a cap of 40 percent; royalty rates for natural gas production under the Alberta Royalty Framework range from a base rate of 5 percent to a cap of 36 percent. The Alberta Royalty 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 Alberta Royalty Framework, the royalty rate applicable to NGL is a flat rate of 40 percent for pentanes and 30 percent for butanes and propane.

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.

On July 18, 2019, the Government of Alberta enacted the *Royalty Guarantee Act* to provide certainty that no major changes will be made to the current oil and gas royalty structure for a period of at least 10 years. The *Royalty Guarantee Act* also confirms that the transition to the MRF for wells drilled on or before December 31, 2016 will occur as planned in 2026.

Any changes to the royalty regime in Alberta may have a material effect on Surge. See "*Risk Factors - Royalty Regimes*."

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government.

For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently.

Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded water flood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded water flood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil means oil produced within the southwest area that is produced from an oil or gas well with a finished drilling date on or after February 9, 1998 or incremental waterflood oil that commenced operation after February 9, 1998. Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded water flood projects with a commencement date on or after February 9, 1998 and before October 1, 2002, and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded water flood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for freehold "new oil" and freehold "third tier oil" and 12.5 for freehold "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at various reference well production rates (m^3 per month) for old oil, new oil, third tier oil and fourth tier oil. Where average wellhead prices are below the established base prices of \$100 per m^3 for third and fourth tier oil and \$50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5 percent for all fourth tier oil, 10 percent for heavy oil that is third tier oil or new oil, 12.5 percent for southwest designated oil that is third tier oil or new oil, 15 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20 percent for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30 percent for all fourth tier oil, 25 percent for heavy oil that is third tier oil or new oil, 35 percent for southwest designated oil that is third tier oil or new oil, 35 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45 percent for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government (effective February 1, 2012), the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act*, *2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations*, *2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, *2012* which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

Base royalty rates are 5 percent for all fourth tier gas, 15 percent for third tier or new gas, and 20 percent for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30 percent for all fourth tier gas, 35 percent for third tier and new gas, and 45 percent for old gas. The current regulatory scheme provides for certain differences with respect to the administration of fourth tier gas which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells. As of April 1, 2021, on associated gas produced from wells other than gas wells, including natural gas produced from oil wells, the Minister of Energy and Resources implemented a 5-year Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax. The moratorium is in connection with the Government of Saskatchewan's Growth Plan and is aimed at meeting the Government of Saskatchewan's regulatory obligations to reduce methane-based GHG emissions by 40 to 45 percent between 2020 and 2025. The Associated Gas Royalty Moratorium is applicable to natural gas produced on or after April 1, 2021 and before April 1, 2026.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002 providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002 providing reduced Crown royalty (a Crown royalty rate of the lesser of “fourth tier oil” Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002 providing reduced Crown royalty (a Crown royalty rate of the lesser of “fourth tier oil” Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the “fourth tier” royalty tax rate;

- Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013 providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of “fourth tier oil” Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the “fourth tier” royalty tax rate;

- Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002 whereby incremental production from approved water flood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005 providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;

- Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005 providing a Crown royalty of 1 percent of gross revenues on EOR projects pre-payout and 20 percent of EOR operating income post-payout and a freehold production tax of 0 percent pre-payout and 8 percent post-payout on operating income from EOR projects; and

- Royalty/Tax Regime for High Water-Cut Oil Wells was amended in May 2021 designed to improve water handling capabilities and extend the producing lives of wells producing large volumes of water. After a qualifying investment has been made to directly improve the water handling capabilities and extend the producing life of a high water-cut oil well, the royalty status will be assigned based upon the well's finished drilling date. Wells drilled before October 1, 2022, will receive "fourth tier oil" royalty/tax rates on all future incremental high water-cut oil production and wells that are drilled on or after October 1, 2022 will receive a 2 percent royalty rate deduction on all future oil production.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 10 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company’s production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Climate Change Regulation

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**"), which was entered into in order to work towards stabilizing atmospheric concentrations of greenhouse gas ("**GHG**") emissions at a level to prevent "dangerous anthropogenic interference with the climate system". The UNFCCC came into force on March 21, 1994. On December 12, 2015, the UNFCCC adopted the Paris Agreement, which Canada ratified on October 5, 2016. Under the Paris Agreement, countries have committed to an ambitious goal of holding the increase in global average temperature to well below 2°C above pre-industrial levels, while they pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. To date, 189 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference, scheduled to take place in November 2021 in Glasgow. The result of The 2021 United Nations Climate Change Conference, more commonly referred to as COP26, was the Glasgow Climate Pact, negotiated through consensus of the representatives of the 197 attending parties. Owing to late interventions from India and China, that weakened a move to end coal power and fossil fuel subsidies, the conference ended with the adoption of a less stringent resolution than some anticipated. The Glasgow Climate Pact reaffirms the long-term global goals (including those in the Paris Agreement) to hold the increase in the global average temperature to below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

In May 2015, Canada submitted its Intended Nationally Determined Contribution to the UNFCCC Secretariat, pledging a 30 percent reduction from 2005 levels—approximately 523 Mt—by 2030. In addition, provincial/territorial and federal leaders met and agreed that they would work together to build a national climate change plan. At a follow-up meeting of the First Ministers and Prime Minister on March 3, 2016, the parties agreed, under the Vancouver Declaration on Clean Growth and Climate Change, to launch a process to develop the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"), which was released on December 9, 2016 at the First Ministers meeting. Saskatchewan was the only province that decided not to adopt the Framework.

On December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the "**HEHE Plan**") which builds on the Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes a $3-billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional $964 million over four years towards renewable energy and grid modernization projects and $300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional $287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, $150 million over three years towards charging and refueling stations across Canada, and $1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels. Also of relevance to the petroleum and natural gas industry, on December 21, 2021, the federal government announced that it intends to publish draft regulations that will implement a ban on the manufacture, import and sale of six categories of single-use plastics. The draft regulations are to come into force in late 2022.

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero GHG emissions by the year 2050. Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. Bill C-12 received royal assent on June 29, 2021 and will legally bind the federal government to a process to achieve net-zero emissions by 2050. Among other things, the legislation sets rolling five-year emissions-reduction targets (starting in 2030) and requires plans to reach each target on a reporting basis and enshrine greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry ("**OBPS**") and a regulatory fuel charge (the "**Fuel Charge**") imposing an initial price of $20/tonne of CO2e emissions. 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 stringency standards set by the federal government. 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. The price is set to increase to $50/tonne of CO2e on April 1, 2022.

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

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

Following the SCC's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum federal stringency standards. Currently the Fuel Charge applies in each of Ontario, Manitoba, Yukon, Alberta, Saskatchewan and Nunavut while the OPBS applies in Manitoba, Prince Edward Island, Yukon, Nunavut and partially in Saskatchewan. For so long as the provincial systems in Prince Edward Island, Alberta (under the *Technology Innovation and Emissions Reduction* (*TIER*) regulation) and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the “**Federal Methane Regulations**”). The *Federal Methane Regulations* seek to reduce emissions of methane from the crude oil and natural gas sector, but will not come into force until January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 Mt by 2030.

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

In March 2016, a Joint Statement on Climate, Energy, and Arctic Leadership was issued. This joint statement set out specific commitments on energy development, environmental protection, and Arctic leadership. In particular, Canada and the US have made commitments to reduce methane emissions by 40-45 percent below 2012 levels by 2025 from the oil and gas sector, finalize and implement the second phase of an aligned GHG emission standard for post-2018 model year on-road heavy duty vehicles, phase out fossil fuel subsidies, accelerate clean energy development and foster sustainable energy development.

The federal government requires that GHG emissions be reported annually. On December 18, 2021, the notice published by the federal government with respect to reporting of GHGs for 2021 was published in the *Canada Gazette* for the 2021 reporting year. The 2021 notice builds on the notice published in 2020 which included an expanded data and methodological requirement for various sectors.

In November 2016, the federal government announced that it would commence development of a performance-based clean fuel standard ("**CFS**") that would incentivize the use of a broad range of low carbon fuels, energy sources and technologies. The objective of the CFS is to achieve 30 Mt of annual reductions in GHG emissions by 2030, as part of efforts to achieve Canada's commitments under the Paris Agreement. On December 13, 2017, Environment and Climate Change Canada ("**ECCC**") published a regulatory framework on the CFS, which outlines the key design elements for the CFS regulation, including its scope, regulated parties, carbon intensity approach, timing, and potential compliance options such as credit trading. On December 18, 2020, the federal government published proposed CFS regulations, the final regulations of which are expected to be published in 2021 with the CFS regulations scheduled to come into force in December 2022.

The proposed CFS regulations take a performance-based approach to reducing GHG emissions and subsequent effects on the Corporation, its operations, obligations or the industry in which it operates. The CFS regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to gradually cut the amount of carbon in their product. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability meet requirements in a cost-effective way that works for their business. The proposed regulations also offer compliance credits to incentive industries to innovate and adopt cleaner technologies to lower their compliance costs.

Surge will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions. The US Environmental Protection Agency ("**EPA**") is proceeding to regulate GHGs under the *Clean Air Act*. This EPA action is subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity.

Alberta

Alberta's Climate Leadership Plan was introduced in November 2015 with the following policy objectives: (i) putting a price on GHG emissions; (ii) phasing out coal-generated electricity by 2030; (iii) having 30 percent of electricity be generated from renewable sources by 2030; (iv) capping oil sands emissions to 100 Mt per year; and (v) reducing methane emissions by 45 percent by 2025.

On January 1, 2018, the *Carbon Competitiveness Incentive Regulation* ("**CCI Regulation**") replaced the *Specified Gas Emitters Regulation*. Under the CCI Regulation, facilities were allowed to emit a certain amount of GHG, free of charge from the carbon levy in place at the time. The CCI Regulation applied to facilities that emitted 100,000 tonnes or more of GHGs in 2003, or a subsequent year. Under the CCI Regulations, a facility would receive performance credits if its GHG emissions are less than the amount freely permitted. If its emissions were above the amount freely permitted, they were required take one or more of the following actions to bring the facility into compliance:

- make improvements at their facility to reduce emissions intensity;
- use emission performance credits generated at facilities that achieve more than the required reductions;
- purchase Alberta-based carbon offset credits; or
- contribute to Alberta's Climate Change and Emissions Management Fund.

Emissions from the oil sands sector (which account for approximately one-quarter of Alberta's annual emissions) have been capped at 100 Mt per year. This cap has been legislated in the *Oil Sands Emissions Limit Act* (Bill 25), which was introduced on December 14, 2016. The legislation includes certain exceptions in respect of cogeneration emissions, upgrading emissions, and potential discretionary exemptions by regulation (likely to accommodate new technological developments).

In June 2019, the Government of Alberta pivoted in its implementation of the Climate Leadership Plan and repealed the Climate Leadership Plan. The *Carbon Competitiveness Incentives Regulation* ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of \$20/tonne. In accordance with the GGPPA, the fuel charge payable in Alberta is currently \$40/tonne of CO2e and will increase to \$50/tonne on April 1, 2022. On December 4, 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation which replaced the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

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

The Government of Alberta aims to lower annual methane emissions by 45 percent by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020 and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting* ("**Directive 060**"). The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal. In May 2020, the Government of Canada and the Government of Alberta announced a preliminary equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply once the agreement is effective.

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

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment* Act, 2010. It deemed the pore space underlying all land in Alberta to be and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. On December 2, 2021, the AER released a Request for Full Project Proposals for Carbon Sequestration Hubs ("**RFPP**"). Following significant interest in carbon capture and storage, the RFPP is intended to facilitate the issuance of rights to Alberta's pore space to proponents to enable the development and operation of carbon storage hubs.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization.

Saskatchewan

In October 2016, Saskatchewan released its Climate Change White Paper, which outlined the principles of the province's approach to climate change, including a focus on both mitigation and adaptation responses to climate change. Following the release of the White Paper, the government worked on developing its comprehensive climate change strategy, which was released in December 2017: Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy (the "**Strategy**"). The Strategy focuses on the principles of readiness and climate resilience, curbing GHG emissions, and preparing for changing conditions such as extreme weather, drought or wildfire. Saskatchewan decided not to sign on to the Framework or to adopt a carbon pricing mechanism, meaning that it will be out of compliance with federal requirements. The Strategy proposes actions in key areas, including (i) natural systems; (ii) physical infrastructure; (iii) economic sustainability; (iv) community preparedness; and (v) measuring, monitoring and reporting. Although no specific emission reduction targets are set out in the Strategy, the Saskatchewan government has indicated that it will support Canada's efforts to meet national commitments under the Paris Agreement. Prior to the release of the Strategy, Saskatchewan relied on the GoGreen Saskatchewan initiative to encourage the reduction of GHG emissions and to educate the public about climate change. Between 2008 and 2015, the Saskatchewan government estimates that it invested $60 million in GoGreen funding through public/private partnerships.

The Government of Saskatchewan announced the introduction of the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province on May 11, 2009. The MRGGA is partially compliant with the federal emissions trading system and was partially proclaimed into force on January 1, 2018. The MRGGA establishes a framework to reduce GHG emissions by 20 percent of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full force on December 18, 2018, establishing the framework of an output-based emissions management framework. The Fuel Charge applies in Saskatchewan and the system implemented by the MRGGA currently meets the federal stringency standards for the emissions it covers and the OBPS applies for those emissions which are not covered.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations, the Management and Reduction of Greenhouse Gases (Reporting and General) Regulations, and The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, The *Oil and Gas Emissions Management Regulations* (the *Saskatchewan O&G Emissions Regulations*) came into effect. The Saskatchewan O&G Emissions Regulations apply to licencees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licencee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 percent to 45 percent by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO2e by 2030.

Under the MRGGA, the output-based performance standards apply to large industrial facilities that emit greater than 25,000 tonnes of CO_2e annually for regulated sectors, including oil and gas. Facilities that emit 10,000 - 25,000 tonnes of CO_2e annually may opt-in.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the Province’s progress on goals set out under the Strategy. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50 percent by 2030.

On October 1, 2019, Bill 147 – An Act to amend the *Oil and Gas Conservation Act*, was proclaimed into force that, in part, amends the *Oil and Gas Conservation Act* to the extent necessary to bring it into alignment with the Saskatchewan *Oil and Gas Emissions Management Regulations*. The *Oil and Gas Emissions Management Regulations* came into effect January 1st, 2019. The *Oil and Gas Emissions Management Regulations* were introduced as a made-in-Saskatchewan results-based regulation to reduce methane-based GHG emissions by 4.5 million tonnes of carbon dioxide equivalent (CO2e) from 2015 levels by 2025.

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 ("**PNG036**"). Licensees in Saskatchewan must comply with the requirements for managing venting and flaring at oil and gas wells and facilities in Saskatchewan as outlined in PNG036, which replaced the previously enacted Upstream Petroleum Industry Associated Gas Conservation. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on or by December 31, 2024.

Saskatchewan has also identified technology as a key driver of emission reductions, including carbon capture use and storage as well as renewable energy.

Land Tenure

Crude oil and natural gas located in the Western Canadian provinces is owned both by the respective provincial governments and by private individuals. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying periods and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Where oil and natural gas is privately owned, rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80 percent of the crude oil and natural gas rights in the southwestern portion of the province. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and Saskatchewan 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 license.

Alberta also 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 all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. In 2013, Alberta Energy placed an indefinite hold on serving shallow rights reversion notices for leases and licences that were granted prior to January 1, 2009. Alberta Energy stated that it will provide the industry with notice if, in the future, a decision is made to serve shallow rights reversion notices.

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

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

In response to COVID-19, the governments of Alberta and Saskatchewan have announced measures to extend or continue Crown leases and permits that may have otherwise expired in the months following the implementation of pandemic response measures.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emitting of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements for the satisfactory abandonment and reclamation of well and facility sites and provides for among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced in association with oil and gas operations, habitat protection and minimum setbacks of oil and gas activities from fresh water bodies. Compliance with such legislation can require significant expenditures and a 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. Certain environmental protection legislation may subject Surge to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault need not be established by claimants affected by such a spill or discharge. Further, as Canadian environmental legislation evolves, the use of administrative penalties by the imposition of fines for the commission of environmental offences on an absolute liability basis has grown.

Environmental legislation is evolving in a manner that has and is expected to continue to result in stricter standards and enforcement, larger fines, liabilities and sanctions, and potentially increased capital expenditures and operating costs. To mitigate potential environmental liabilities, Surge in addition to implementing policies and procedures designed to prevent an accidental spill or discharge, maintains insurance at industry standards.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act* and the *Canadian Environmental Assessment Act*, provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On June 21, 2019 Bill C-48 (the OTMA), came into force. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. This legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

As previously discussed in *Industry Conditions – Restrained Pipeline Capacity and Differential Volatility*, the CERA and the IAA came into force and the NEB was replaced with the CER in 2019. In addition, the Impact Assessment Agency ("**IA Agency**") replaced the Canadian Environmental Assessment Agency.

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments, including the enactment of the IAA. Pursuant to the IAA, "Designated Projects" will require an impact assessment as part of their regulatory review. The impact assessment, conducted by the IA Agency, and may be conducted by a joint review panel with other provincial governments or the CER, as needed and includes expanded criteria the review panel may consider when reviewing an application. Under the CERA, certain project are considered Designated Projects requiring an impact assessment and those project which are subject to the CERA will undergo an integrated impact assessment, led by the IA Agency.

The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. In conducting its assessment, the IA Agency must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75 kilometers of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

As stated, the objective of the legislative changes are to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are time limits the relevant regulatory authority will have to issue its report and recommendation. Designated Projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. The impacts of the IAA are unknown on oil and natural gas projects as few have been subject to the new regime. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has yet to be substantially tested.

On July 17, 2020, the federal government published its Strategic Assessment of Climate Change ("**SACC**") to assess the impacts of climate change in federal impact assessments conducted under the IAA. The SACC applies to Designated Projects under the IAA. Guidance for projects regulated by the CER will consider the principles and objectives of the SACC. The SACC may also apply to environmental reviews by other federal lifecycle regulators, and be used in regional assessments. ECCC has indicated it plans to review and update the SACC every 5 years. Proponents will be required to provide information about the emissions intensity of their projects, and this information will be compared to national and international projects of a similar scope and nature. A description of mitigation measures and the plan for the project to achieve net-zero emission by 2050 will also be required, as is information on the project's ability to scope with the physical impacts of climate change.

Alberta

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* ("**EPEA**"), the *Water Act* and the *Oil and Gas Conservation Act* ("**ABOGCA**"). EPEA, the *Water Act* and the ABOGCA impose strict environmental standards with respect to releases of effluents and emissions, require stringent compliance, reporting and monitoring obligations, and impose significant penalties for non-compliance.

EPEA regulates the protection of the environment in Alberta, including among others the designation of environmentally impacted sites, issuance of environmental protection orders, and obligations to report releases of substances. EPEA provides for the prohibition on the discharge of substances which cause an adverse effect to the environment and assigns responsibility for such adverse effect to a "person responsible", which is defined broadly. This definition includes previous owners of the substance or thing, any person who had charge, management or control of the substance or thing, including the sale, handling, use, storage or disposal of the substance or thing any successor or assignee of such person.

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the AER assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the ABOGCA. On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Parks ("**AEP**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AEP in the areas of environment and water under EPEA and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF 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 *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land, and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 percent of the province's oilsands resources and much of the Cold Lake oilsands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access.

The South Saskatchewan Regional Plan ("**SSRP**") was approved by the Government of Alberta on July 23, 2014 and became effective on September 1, 2014. The SSRP is the second regional plan developed under the ALUF and covers approximately 83,764 square kilometres and includes 44 percent of the province's population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, oil and gas companies must nonetheless minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. Freehold mineral rights will not be subject to this restriction. With the implementation of the new Alberta regulatory structure under the AER, AEP will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Pursuant to several ministerial orders passed pursuant to s. 52.1(2) of the Alberta *Public Health Act* which declared a state of public health emergency in Alberta due to the COVID-19 pandemic, certain industrial environmental reporting requirements including the extension of deadlines or the suspension of reporting requirements under EPEA and the *Water Act*. The ministerial orders expired on August 14, 2020 and all environmental reporting should resume in accordance with the prescribed deadlines and requirements.

Saskatchewan

Saskatchewan's Ministry of the Economy and the Oil and Gas Conservation Board collectively regulate oil and gas activities in the province, which is primarily governed by the *Natural Resources Act* and *The Oil and Gas Conservation Act* ("**SKOGCA**").

The *Environmental Management and Protection Act* ("**EMPA**") regulates the protection of the environment in Saskatchewan, including among others the designation of environmentally impacted sites, issuance of environmental protection orders, and obligations to report releases of substances. Most importantly, the EMPA prohibits the discharge of substances causing adverse effects to the environment, and assigns responsibility for such adverse effects to a broad category of "persons responsible." This includes the person who caused or contributed to the discharge (i.e. fugitive release of sour gas or flaring in excess of the permitted levels), had possession or control of the substance, as well as every owner and occupier of the land, including subsequent owners and occupiers and any person transporting the substance.

In May 2011, Saskatchewan passed changes to SKOGCA. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers, and procedural aspects, including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* in an urgent response to a decision from the Alberta Court of Queen's Bench, which was affirmed by a majority at the Alberta Court of Appeal. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the *Oil and Gas Conservation Act* (Alberta) and the *Bankruptcy and Insolvency Act* ("**BIA**"), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA.

On January 31, 2019, the Supreme Court of Canada ruled on the appeal of Redwater in *Orphan Well Association v. Grant Thornton Limited,* 2019 SCC 5 in favour of the AER and Orphan Well Association. Specifically, the SCC held that while trustees will not be personally liable for abandonment and reclamation obligations, the estate will remain liable for such obligations. As a result, reclamation and abandonment liabilities must be dealt with before there can be any distribution to the insolvent parties' creditors, including its secured creditors.

In response to the SCC's decision in *Redwater*, the AER began working on an improved liability management framework. On July 30, 2020, the Government of Alberta announced that it will introduce a new Liability Management Framework ("**LMF**") for the oil and gas industry which is intended to replace the Alberta Liability Management Program (the "**LMR Program**"). The LMF is intended to implement a holistic and full lifecycle approach to reclamation and remediation obligations. Since the announcement, the Government of Alberta has gradually begun to phase-in the LMF through legislative and AER directive amendments.

Prior to the change, the AER administered the Licensee Liability Rating Program (the "**AB LLR Program**") as part of the Liability Management Rating Assessment Process. The AB LLR Program was a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The AB LLR Program required a licensee whose deemed liabilities exceed its deemed assets (and therefore the licensee has a resulting in a license liability rating ("**LLR**") of less than 1.0) to provide the AER with a security deposit. In certain circumstances, for example during the transfer of AER licenses between parties, the AER required that the transferee must achieve an LLR of 2.0 or higher immediately following the proposed transfer of the applicable licenses. The ratio of deemed liabilities to deemed assets was assessed once each month and upon the submission of a license transfer application, and failure to post the required security deposit could result in the initiation of enforcement actions by the AER.

The ABOGCA established an Orphan Fund which is run by the Orphan Well Association ("**OWA**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licencee or working interest participant becomes insolvent or is unable to meet its obligations. The OWA is an industry-funded, non-profit organization that operates under authority given by the AER. In April 2020, the Government of Alberta passed Bill 12: the *Liabilities Management Statutes Amendment Act* (the "**LMSAA**"), which came into force on proclamation. The LMSAA places the burden of a defunct licencees' abandonment and reclamation obligations first on the defunct 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.

Under the LMF, the OWA will have broader authority to assist in the reclamation and remediation of wells, facilities and pipelines. The Orphan Fund was originally intended to be funded exclusively by licencees in the AB LLR Program and Alberta Oilfield Waste Liability Program (the "**AB OWL Program**") who contributed to a levy administered by the AER. However, the Government of Alberta has loaned the Orphan Fund approximately $355 million. The Government has also covered $113 million in levy payments that licencees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. Collectively, these programs were designed to minimize the risk of the Orphan Fund posed by the unfunded liabilities of licencees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In April 2020, the federal government also announced that up to $1 billion in funding would be available to Alberta's oilfield service contractors to perform reclamation work as part of the federal government's COVID-19 Economic Response Plan and $200 million would be offered to the OWA as a repayable loan. In May 2020, the Government of Alberta launched the site rehabilitation program which was funded primarily by the federal government's COVID-19 Economic Response Plan. Pursuant to the program, contractors are provided with grants to perform well, pipeline and oil and gas site closure and reclamation work. The Government of Alberta also announced the extension of a $100 million repayable loan to the OWA.

The Government of Alberta has said the LMF is expected to address five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) licencee capability assessment system to provide proactive support through ongoing financial capability review; (iii) mandatory spend targets to support inventory reduction; (iv) a process to address legacy and post-closure sites or sites that were remediated, reclaimed or abandoned prior to the LMF; and (v) the OWA taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure.

On December 1, 2021, the Government of Alberta announced amendments to Directive 006: *Licensee Liability Rating (LLR) Program* and a new Directive 008: *Licensee* Life-Cycle Management. A new Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* was also introduced in April 2021 which introduces new criteria for the AER to consider whether an applicant, licencee or approval holder poses an "unreasonable risk". Among other changes under the LMF, the AB LLR Program will be 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 LMF will also provide proactive support to distressed operators and will require companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the LMF, each licencee will be required to meet mandatory annual spend targets for well closures and abandonments starting January 2022. It is expected that the mandatory spend targets will be released in July 2022.

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

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER has also announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Participants seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The ABC, together with the inventory reduction program implemented under the AB LMF, which implements mandatory closure spend targets over a 5-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

The implementation of the LMF is still ongoing and the AER has announced that several changes are still expected to improve existing liability programs and implement the new LMF. The expectation is the LMF will replace the AB LMR Program in its entirety, however, such transition will require time as the AB LMR Program is integrated throughout the regulatory regime including Directives and legislation. No timeline has been committed to for the implementation of the LMF, however, implementation will likely continue throughout 2022, with the gradual and phasing changes to legislative, regulatory and AER directives in order to adequately implement and integrate the LMF.

The Corporation cannot predict what the LMF may look like but the implementation of the LMF and the new regulatory framework will have an impact on crude oil and natural gas production in Alberta, including Surge's business.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements 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 an orphan well fund (the "**Oil and Gas Orphan Well Fund**"). The Oil and Gas Orphan Well Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Saskatchewan Ministry of the Economy announced that it considers all license transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with license transfer approvals.

RISK FACTORS

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. The following information is a summary only of certain risk factors relating to the Corporation and should be read in conjunction with the detailed information appearing elsewhere in this Annual Information Form. Prospective investors should carefully consider the risk factors set out below and consider all other information contained in this Annual Information Form and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

COVID-19

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide could have an adverse impact on Surge's business, including changes to the way we and our counterparties operate, and on our financial results and condition. The spread of the COVID-19 pandemic, given its severity and scale, continues to adversely affect our business to varying degrees and many of our customers and business partners and also continues to pose risks to the global economy and the petroleum and natural gas industry more broadly. While a number of containment measures have been and continue to be gradually eased or lifted across some regions, additional safety precautions and operating protocols aimed at containing the spread of COVID-19 have been and continue to be instituted in line with guidance of public health authorities. In addition, the emergence of the second, third and fourth waves of the COVID-19 pandemic, together with the emergence of new COVID-19 variant strains such as the Delta strain and the Omicron strain, has led to the imposition of containment measures to varying degrees in many regions within Canada and globally. These containment measures continue to impact global economic activity, including the ability to move towards recovery of the global economy and such measures also contribute to the decreased demand for hydrocarbons, increased market volatility and continued changes to the macroeconomic environment. As the impacts of the COVID-19 pandemic continue to materialize, the prolonged effects of the disruption have had and continue to have adverse impacts on Surge's business strategies and initiatives, resulting in ongoing effects to our financial results, including the increase of counterparty, market and operational risks.

The COVID-19 pandemic has resulted, and may continue to result, in disruptions to some of Surge's business partners, clients and customers and the way in which we conduct our business, including prolonged duration of staff working from home. These factors have impacted, and may continue to impact, our business operations and continuity of relationships with our business partners. Operational risks which may affect the Corporation or our business partners include the need to provide enhanced safety measures for employees and customers; complying with rapidly changing regulatory guidance; addressing the risks of attempted fraudulent activity and cybersecurity threat behavior; and protecting the integrity and functionality of the Corporation's systems, networks and data as a larger number of employees work remotely.

If the COVID-19 pandemic is further prolonged, including the possibility of additional subsequent waves, and introduction of new variants, or further diseases merge that give rise to similar effects, the adverse impact on the economy could deepen and result in further volatility and declines in commodity and financial markets. Moreover, it remains uncertain how the macroeconomic environment will be impacted following the COVID-19 pandemic. Unexpected developments in commodity and financial markets, regulatory environments, industrial activity or consumer behavior and confidence may also have adverse impacts on the Corporation's business and financial condition, potentially for a substantial period of time.

Credit Facilities Risks

The amounts authorized under the First Lien Credit Facilities is dependent on the borrowing base determined by the lenders thereunder. The Corporation is required to comply with covenants under the Credit Facilities which may affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facilities, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facilities, the lenders under the Credit Facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facilities may impose operating and financial restrictions on the Corporation that could include restrictions on the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The impact of the Supreme Court of Canada's decision in the *Redwater* 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.

Operational Risks

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering and oil spills, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury. In accordance with industry practice, Surge is not fully insured against all of these risks, nor are all such risks insurable. Although Surge maintains liability insurance in an amount which it considers adequate, the nature of these risks is such that liabilities could exceed policy limits, in which event Surge could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Surge and may delay exploration and development activities.

Oil and natural gas exploration and development activities are dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. Unexpected adverse weather conditions, such as flooding or prolonged break-up, can have a significant negative impact on capital expenditures, operations and costs.

To the extent Surge is not the operator of its oil and natural gas properties, it is dependent on such operators for the timing of activities related to such properties and is largely unable to direct or control the activities of the operators. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although Surge intends to operate the majority of its properties, there is no guarantee that it will remain operator of such properties or that Surge will operate other properties it may acquire in the future.

In addition, the success of Surge will be largely dependent upon the performance of its management and key employees. Surge does not have any key man insurance policies and, therefore, there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on Surge.

Surge's ability to market oil and natural gas from its wells also depends upon numerous other factors beyond its control, including, among other things, the availability of natural gas processing and storage capacity, the availability of pipeline capacity, the price of oilfield services and the effects of inclement weather. Because of these factors, Surge may be unable to market some or all of the oil and natural gas it produces or to obtain favourable prices for the oil and natural gas it produces.

Volatility of Oil and Natural Gas Prices and Markets

Surge's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on Surge's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global and North American supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of Surge including, but not limited, to the world economy and the OPEC's ability to adjust supply to world demand, government regulation, political stability, COVID-19 and the availability of alternative fuel sources. In addition, the prices received by Surge for its oil are subject to differentials against such benchmarks as WTI and Edmonton Par which can fluctuate substantially and result in Surge realizing prices substantially below such benchmarks. Oil and natural gas producers in Western Canada may receive significantly discounted prices for some of their production due to regional constraints on their ability to transport and sell such production, including to international markets. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources.

Decreases in oil and natural gas prices realized by Surge will result in reduced net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of Surge's reserves. Any further substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in Surge's net production revenue, cash flows and profitability causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Surge will in part be determined by Surge's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available, including under the Credit Facilities, and could require that a portion of its bank debt be repaid.

Surge may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Surge will not benefit from such increases.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by certain changes in government at a federal level and, in the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental and climate change regulation that have been announced or may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, the Corporation's cash flow resulting in a reduced capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the U.S. administration has withdrawn the United States from the Trans-Pacific Partnership ("**TPP**") and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The U.S. has not indicated any intention to rejoin the TPP but could try to negotiate stronger labour and environmental standards. On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States. The political unrest associated with the transition to the new Biden administration over the past year is unprecedented in the United States, and the short and long-term impacts on business and capital markets are unknown.

In addition, NAFTA has been renegotiated and on December 10, 2019, and Canada, the U.S. and Mexico signed the USMCA which replaced NAFTA. See "*Industry Conditions – The North American Free Trade Agreement*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the new U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including Surge.

In addition to the political disruption in the United States, on January 31, 2020 the United Kingdom officially withdrew from the European Union. Since the United Kingdom's departure, it remains unclear what the effects of this will be as a final deal was reached between the European Union and the United Kingdom which came into effect on December 31, 2020. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on Surge's ability to market products internationally, increase costs for goods and services required for operations, reduce access to skilled labour and negatively impact business, operations, financial conditions and the market value of the Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy.

The federal government was re-elected in 2019, but in a minority position. Another federal election was held on September 20, 2021 and the federal government was re-elected again in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the petroleum and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial government level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the petroleum and natural gas industry, which effect could prove to be material over time.

Climate Change

Public support for climate change action and receptivity to new technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. There has also been increased activism, including threats of culpability, legal action against oil and gas producers, and public opposition to fossil fuels and the oil and gas industry in which the Corporation operates. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify a class action against the Government of Canada for climate related matters. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for climate-related harms. The application was denied and Environment JEUnesse appealed to the Appeal Court of Québec on February 23, 2021. The appeal was dismissed on December 13, 2021. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against crude oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Public and government hostility toward the oil and gas industry could reduce demand for oil and gas and, therefore, adversely affect market prices for the Corporation’s production. Existing and future laws and regulations may impose additional costs on companies operating in the oil and gas industry or significant liabilities for failure to comply with their requirements. Concerns over climate change and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry in general.

Surge’s exploration and production facilities and other operations and activities emit GHGs which may require us to comply with GHG emissions legislation at the provincial or federal level.

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a signatory to the Paris Agreement, which was ratified in Canada on October 5, 2016, the Government of Canada pledged to cut its GHG emissions by 30 percent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the nation-wide price on carbon emissions.

In the spring of 2021, the SCC upheld the GGPPA as constitutional. Currently the Fuel Charge applies in Alberta and Saskatchewan while the OPBS applies in partially in Saskatchewan. For so long as the provincial systems in place in Alberta 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. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

The perceived elevated long-term risks associated with regulatory changes or other market developments related to climate change have also impacted the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other institutional investors which promote direct engagement and dialogue with companies in their portfolios on climate change action and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to crude oil and natural gas and related infrastructure businesses and projects. The impact of such efforts may require the Corporation's management to dedicate significant time and resources to these climate change related concerns, may adversely affect the Corporation's operations, the demand for and price of the Corporation's securities and may negatively impact the Corporation's cost of capital and access to the capital markets, which negative impact could prove to be material over time.

Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses and in the long-term reducing the demand for oil and natural gas production, resulting in a decrease in our profitability and a reduction in the value of our assets or asset write-offs.

See "*Industry Conditions – Climate Change Regulation*".

Environmental Concerns

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that Surge may be in noncompliance with an environmental law, regulation, permit, licence, or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose Surge to fines or penalties, third-party liabilities or to the requirement to remediate, which could be material.

The operational hazards associated with possible blowouts, accidents, oil spills, natural gas leaks, fires, or other damage to a well or a pipeline may require Surge to incur costs and delays to undertake corrective actions, could result in environmental damage or contamination or could result in serious injury or death to employees, consultants, contractors or members of the public, creating the potential for significant liability to Surge. Also, the occurrence of any such incident could damage Surge's reputation in the surrounding communities and make it more difficult for Surge to pursue its operations in those areas.

Compliance with environmental laws and regulations could materially increase Surge's costs. Surge may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, Surge may be required to incur significant costs to comply with future federal or provincial greenhouse gas emissions reduction requirements or other regulations, if enacted. See "*Industry Conditions – Environmental Regulation*".

The oil and natural gas industry elicits concerns about climate change, as well as general public opposition to the industry. As a result, industry participants may be subject to increased public activism, which could result in increased costs due to delays or damage.

Although Surge maintains insurance consistent with prudent industry practice, it is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, Surge's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. It is also possible that changing regulatory requirements or emerging jurisprudence could render such insurance of less benefit to Surge.

Dividends

The Credit Facilities contain 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 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 compliance with the provisions respecting the payment of dividends contained in the Credit Facilities, prevailing economic and competitive environment, results of operations, fluctuations in working capital, the price of oil and gas, the taxability of the Corporation, the Corporation's ability to raise capital, the amount of capital expenditures, the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends, applicable law and other factors. See "*Dividend Policy*."

Royalty Regimes

There can be no assurance that the federal government and the provincial governments in the jurisdictions in which the Corporation operates 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. The royalty regime in Alberta, Saskatchewan and any other jurisdictions in which the Corporation's oil and natural gas assets are located may be subject to further review and changes which could adversely impact the Corporation's financial condition and operations. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. See "*Industry Conditions - Provincial Royalties and Incentives*".

Gathering and Processing Facilities, Pipeline Systems and Rail

Surge delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that Surge can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. On February 19, 2019, the Government of Alberta announced it would lease 4,400 rail cars capable of transporting 120,000 bbl/d of crude oil out of the province to alleviate transportation constraints impacting Canadian oil prices. In the spring of 2019, the Government of Alberta announced it would cancel the program and assign the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold $10.6 billion worth of crude-by-rail contracts to the private sector. The ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the inability to realize the full economic potential of Surge's production or in a reduction of the price offered for its production.

The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect Surge's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm Surge's business and, in turn, its financial condition, operations and cash flows. Announcements and actions taken by the federal government and the Government of Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, the impact of the new IAA regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear as it remains relatively untested since its enactment.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of Surge's production may, from time to time, be processed through facilities owned by third parties and over which it does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on Surge's ability to process its production and deliver the same for sale. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Fixed Price Hedging

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Industry Regulation and Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Surge will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Surge. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw. Surge's ability to increase reserves and production in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling.

The marketability of oil and natural gas acquired or discovered will be affected by numerous factors beyond the control of Surge. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing, transportation and royalty rates) are subject to extensive controls and regulations imposed by various levels of government, including those described above under the heading "Industry Conditions", which may be amended from time to time. Surge's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Changes to the regulation of the oil and gas industry in jurisdictions in which Surge operates may adversely impact Surge's ability to economically develop existing reserves and add new reserves.

Variations in Foreign Exchange Rates and Interest Rates

Surge's expenses will be denominated in Canadian dollars, while the price of oil and natural gas will generally be denominated in U.S. dollars or impacted by the Canadian dollar to U.S. dollar exchange rate. As the exchange rate for the Canadian dollar versus the U.S. dollar increases, Surge will generally receive fewer Canadian dollars for its production. If the value of the Canadian dollar against the U.S. dollar increases, the financial results of Surge may be negatively affected. Future fluctuations in the Canadian/United States foreign exchange rate may impact the future value of Surge's reserves as determined by independent evaluators. In addition, variations in interest rates could result in a significant change in the amount Surge will pay to service debt, potentially adversely affecting the value of the Common Shares. Surge's management may hedge interest rates to mitigate these risks.

Price Volatility of Publicly Traded Securities

In recent years, the securities markets in Canada and the United States have experienced a high level of price and volume volatility, and the market price of securities of many companies, particularly those considered to be development stage companies, has experienced wide fluctuations in price which have not necessarily been related to the operating performance, underlying asset values or prospects of such companies. There can be no assurance that continual fluctuations in price will not occur. It is likely that the market price for the Common Shares will be subject to market trends generally, notwithstanding the financial and operational performance of Surge.

Abandonment and Reclamation Costs

As a general rule, the current oil and gas asset abandonment, reclamation and remediation ("**A&R**") liability regime in Alberta limits each party's liability to its proportionate ownership of an asset. In the case where one joint owner of an oil and gas asset becomes insolvent and is unable to fund the required A&R activities associated with such asset, the solvent working interest counterparties can recover the insolvent party's share of the remediation costs from the Orphan Well Fund. See "*Industry Conditions – Liability Management Ratings Programs*".

As a result of the Supreme Court of Canada's January 2019 decision in the *Redwater* case, a trustee in bankruptcy is not permitted to renounce uneconomic oil and gas assets and leave these assets to be remediated by the Orphan Well Fund, thereby avoiding the environmental liabilities of the estate it is administering. Accordingly, the AER may now use Alberta's provincial legislative scheme to prevent the repudiation or renunciation of an insolvent company's assets by a trustee and require the trustee to satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors. In response to the Supreme Court's decision, the AER and the Government of Alberta began revising Alberta's current liability framework with the introduction of the LMF in July 2020, which remains ongoing. Surge cannot predict how the Government of Alberta or the AER will seek to implement the LMF over the year, the LMF framework will have an impact on crude oil and natural gas production in Alberta, including Surge's business.

The AER's new LMF may impact the Corporation's ability to transfer its licences, approvals or permits in the course of a divestment, and may result in increased costs, disclosure of information, increased scrutiny of the financial capabilities of both the transferee and the transferor and delays or require changes to or abandonment of projects and transactions. As a result of the decision in Redwater, lenders may reduce the availability of credit to oil and gas issuers that utilize secured loans, thereby negatively affecting the financial capacity of such issuers, including potential partners and counterparties of the Corporation. Lenders also may generally increase their scrutiny of oil and gas assets held by producers, including the Corporation, and the associated A&R liabilities in determining whether to provide credit, may require borrowers to adhere to more stringent A&R-related operational covenants, and may increase the cost of providing credit.

While the impact on the Corporation of any legislative, regulatory or policy decisions as a result of the Redwater decision cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact the Corporation and materially and adversely affect, among other things, the Corporation's business, financial condition, results of operations and cash flow.

There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or jointly with the federal government, as the new LMF is implemented in the province.

Substantial Capital Requirements; Liquidity

Surge may have to make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If revenues or reserves decline, Surge may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require Surge to alter its capitalization significantly. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects.

Reserve Estimates

There are numerous uncertainties inherent in evaluating quantities of reserves and the net present value of future net revenue to be derived therefrom, including many factors beyond the control of Surge. The reserves information contained in the Reserves Report and set forth herein, including information respecting the net present value of future net revenue from reserves, represents an estimate only. This estimate is based on a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the Reserves Report were prepared and many of these assumptions are subject to change and are beyond the control of Surge. Ultimately, the actual reserves attributable to Surge's properties will vary from the estimates contained in the Reserves Report and those variations may be material and affect the market price of the Common Shares.

Reserve Replacement

Surge's future oil and natural gas reserves and production and the cash flows to be derived therefrom are highly dependent on successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Surge may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in reserves will depend not only on Surge's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Surge's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Sour Natural Gas

Some of the Corporation's current or future properties include wells that produce sour natural gas and facilities that process sour natural gas. An accidental discharge or leak of sour natural gas can be fatal or cause serious injury. The dangers associated with drilling for, producing, processing and transporting sour natural gas necessitate increased environmental, health and safety compliance costs to Surge and any accidental discharge or leak of sour natural gas could lead to significant liabilities to Surge. Surge has implemented policies and protocols to address this risk, but it is not possible for any issuer to eliminate all of the risks associated with producing, processing and transporting sour natural gas.

Delay in Cash Receipts and Credit Worthiness of Counterparties

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of Surge's properties, and by the operator to Surge, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of Surge's properties or the establishment by the operator of reserves for such expenses. In addition, the insolvency or financial impairment of any counterparty owing money to Surge, including industry partners and marketing agents, could prevent Surge from collecting such debts.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. Certain countries have imposed strict financial and trade sanctions against Russia, including with respect to oil and gas exports from Russia. These and any additional sanctions applied as the conflict continues may have a significant impact on worldwide prices of oil and natural gas and the world economy. The outcome and impact of the conflict and any sanctions imposed on Russia as a result remain uncertain.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Issuance of Debt

From time to time Surge may enter into transactions to acquire assets or shares of other corporations. These transactions may be financed partially or wholly through debt, which may increase debt levels above industry standards. Surge's articles and by-laws do not limit the amount of indebtedness it may incur. The level of Surge's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Possible Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation has recently completed a number of acquisitions and dispositions and may complete future acquisitions and dispositions to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits including, among other things, potential cost savings. Achieving the benefits of recent and any future acquisitions the Corporation may complete will depend in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with those of the Corporation. The integration of acquired assets requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of recent and any future acquisitions. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of Surge's non-core assets may realize less on disposition than their carrying value on the consolidated financial statements of the Corporation.

Cost of New Technologies

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

Information Technology Systems and Cyber-Security

Surge 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. Surge depends on various information technology systems to estimate reserve quantities, process and record financial data, manage the land base, analyze seismic information, administer contracts with operators and lessees and communicate with employees and third-party partners.

Further, Surge 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 its 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 Surge's business activities or competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on Surge's performance and earnings, as well as on Surge's reputation. Surge has technical and process controls in line with industry-accepted standards to protect its information assets and systems; however, these controls may not adequately prevent cyber-security breaches. 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 Surge's business, financial condition and results of operations.

Hydraulic Fracturing

The proliferation of the use of hydraulic fracturing as a recovery technique employed in oil and natural gas drilling has given rise to increased public scrutiny of its environmental aspects, particularly with respect to its potential impact on local aquifers. Surge utilizes hydraulic fracturing in a significant portion of the light oil wells it drills and completes. Negative public perception of hydraulic fracturing may place pressure on governments in the jurisdictions where Surge operates to implement additional regulatory requirements or limitations on the utilization of hydraulic fracturing, which in turn could restrict Surge's operations and increase its costs.

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 costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Surge is ultimately able to produce from its reserves.

Dilution

Common Shares, including rights, warrants, special warrants, subscription receipts and other securities to purchase, to convert into or to exchange into Common Shares, may be created, issued, sold and delivered on such terms and conditions and at such times as the Board may determine. In addition, Surge may issue additional Common Shares from time to time pursuant to Surge's stock option plan and stock incentive plan. The issuance of these Common Shares would result in dilution to holders of Common Shares.

Net Asset Value

Surge's net asset value will vary depending upon a number of factors beyond the control of Surge's management, including oil and natural gas prices. The trading price of the Common Shares is also determined by a number of factors which are beyond the control of management and such trading price may be greater than or less than the net asset value of Surge.

Reliance on Management

Shareholders will be dependent on the management of Surge in respect of the administration and management of all matters relating to Surge and its properties and operations. Investors who are not willing to rely on the management of Surge should not invest in Common Shares.

Permits and Licenses

The operations of Surge may require licenses and permits from various governmental authorities. There can be no assurance that Surge will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells as determined appropriate by management, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat a claim of Surge which could result in a reduction of Surge's interest in a property or well and the revenue received by Surge therefrom.

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, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to resources and various properties in Western Canada. Such claims, in relation to any of Surge's lands, if successful, could have an adverse effect on its operations.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Corporate Matters

Certain of the directors and officers of Surge are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of Surge, as the case may be, and as officers and directors of such other companies.

Failure to Maintain Listing of the Common Shares and the Debentures

The Common Shares and the Debentures are currently listed for trading on the facilities of the TSX. The failure of Surge to meet the applicable listing or other requirements of the TSX in the future may result in the Common Shares and/or the Debentures ceasing to be listed for trading on the TSX, which would have a material adverse effect on the value of the Common Shares and/or Debentures. There can be no assurance that the Common Shares and Debentures will continue to be listed for trading on the TSX.

Structure of Surge

From time to time, Surge may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of Surge and its subsidiaries. If the manner in which Surge structures its affairs is successfully challenged by a taxation or other authority, Surge and the holders of Common Shares may be adversely affected.

Changes in Legislation

It is possible that the Canadian federal and provincial government or regulatory authorities could choose to change the Canadian federal income tax laws, royalty regimes, liability management, environmental and climate change laws or other laws applicable to oil and gas companies and that any such changes could materially adversely affect Surge, its shareholders and the market value of the Common Shares.

Additional information on the risks, assumptions and uncertainties are found in this Annual Information Form under the heading "*Special Note Regarding Forward Looking Statements*".

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. Surge cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on its business, financial condition, results of operations and cash flows by decreasing profitability, increasing costs, limiting access to capital and decreasing the value of Surge's assets.

Global Events Outside of the Corporation's Control, such as Natural Disasters, Wars or Health Epidemics

The Corporation may be impacted by business interruptions resulting from pandemics and public health emergencies, including those related to COVID-19 coronavirus, geopolitical actions, including war and terrorism or natural disasters including earthquakes, typhoons, floods and fires. An outbreak of infectious disease, a pandemic or a similar public health threat, such as the recent outbreak of the novel coronavirus known as COVID-19, or a fear of any of the foregoing, could adversely impact us by causing operating, manufacturing supply chain, clinical trial and project development delays and disruptions, labour shortages, travel and shipping disruption and shutdowns (including as a result of government regulation and prevention measures). It is unknown whether and how the Corporation may affected if such an epidemic persists for an extended period of time. The Corporation may incur expenses or delays relating to such events outside of our control, which could have a material adverse impact on our business, operating results and financial condition.

Forward-Looking Information

Shareholders and prospective investors are cautioned not to place undue reliance on Surge's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2021, there were (i) no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that it believes would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

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

AUDITOR, TRANSFER AGENT AND REGISTRAR

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

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

INTEREST OF EXPERTS

The Reserves Report and certain reserves estimates contained in filings made by the Corporation under NI 51-102 during the year ended December 31, 2021 were prepared by Sproule. As at the date of this Annual Information Form, the directors, officers, employees and consultants of Sproule who participated in the preparation of the Reserves Report or such reserves estimates or who were in a position to directly influence the preparation or outcome of the preparation of the Reserves Report or such reserves estimates, as a group, owned, directly or indirectly, less than 1 percent of the outstanding Common Shares.

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

ADDITIONAL INFORMATION

Additional information concerning the Corporation may be found under the Corporation's profile on SEDAR at www.sedar.com. Additional information, including information concerning directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, will be contained in the information circular of the Corporation for the annual general meeting of the holders of Common Shares scheduled to be held in 2022. Additional financial information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2021.

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, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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, 2021, 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	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, 2021	Canada				
Total			**Nil**	**1,743,684**	**Nil**	**1,743,684**

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, 2021)".

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta

APEGA Permit Number 00417

“Original signed by Mathew Tymchuk, P.Eng.”
Matthew Tymchuk, Manager Engineering
RM APEGA ID# 74309
February 23, 2022

“Original signed by Gary R. Finnis, P.Eng.”
Gary R. Finnis, Senior Manager, Engineering
RM APEGA ID#: 62965
February 23, 2022

“Original signed by Alec Kovaltchouk, P.Geo.”
Alec Kovaltchouk, VP, Geoscience
RM APEGA ID#: 72150
February 23, 2022

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, 2021, 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, 2021 (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.

[Balance of Page Intentionally Left Blank.]

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

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

March 9, 2022

SCHEDULE "C"

Audit Committee Charter

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.