SURGE ENERGY INC

Annual Information Form

For the Year Ended December 31, 2015
Dated March 16, 2016

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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;

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

"**Credit Facility**" means the $400 million extendible revolving term credit facility of the Corporation with a banking syndicate led by National Bank of Canada, as amended from time to time;

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

"**Reserves Report**" means the independent engineering report dated February 3, 2016 and effective December 31, 2015 prepared by and containing the evaluation of Sproule of the oil, NGL and natural gas reserves attributable to the properties of the Corporation;

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

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

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

bbl	Barrel
bbls	Barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
bbl/d	barrels per day
NGLs	natural gas liquids
stb	stock tank barrel

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule

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 “netback” which is not defined by IFRS and therefore may not be comparable to performance measures presented by others. In this AIF, “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, 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 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 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;
- 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;
- 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 and the amount of timing of dividends;
- treatment under governmental regulatory regimes and tax and royalty laws;
- criteria and considerations in participations and acquisitions;
- 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;
- the success of the Corporation's operations and exploration and development activities;
- 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;
- general economic and financial market conditions;
- the success, nature and timing of water flood activities;
- the ability of the Corporation to secure necessary personnel, equipment and services;
- government regulation in the areas of taxation, royalty rates and environmental protection; and
- the success of exploration and development activities.

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

- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;

- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- geological, technical, drilling, completion and processing problems;
- results of water flood responses;
- the outcome of litigation 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;
- failure to realize the anticipated benefits of acquisitions; 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.

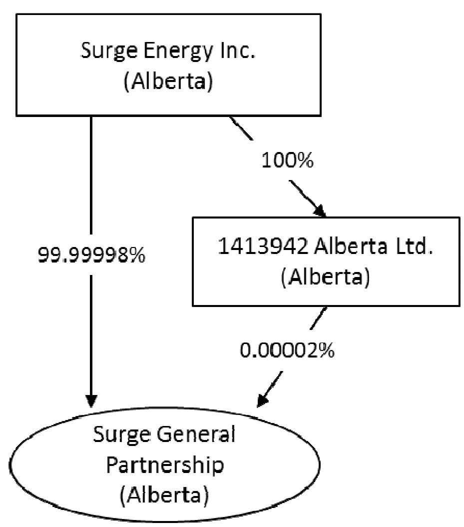
Corporate Structure

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.

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.

Intercorporate Relationships

The Corporation currently has one wholly-owned subsidiary, 1413942 Alberta Ltd. The Corporation and 1413942 Alberta Ltd. are the partners of Surge General Partnership. The corporate structure of the Corporation and its subsidiaries is as set forth in the diagram below:



DEVELOPMENT OF THE BUSINESS

General

The Corporation is an independent Calgary, Alberta-based oil and gas company operating primarily in Alberta and Saskatchewan. The Common Shares are listed on the TSX under the symbol “SGY”.

Three Year History

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

Year ended December 31, 2013

Management Reorganization

On May 8, 2013, the Corporation announced the appointment of Mr. Paul Colborne as President and Chief Executive Officer, the resignation of Mr. P. Daniel O'Neil as President and Chief Executive Officer, and the appointment of Mr. Murray Bye as the Vice President, Production.

In connection with his appointment as President and Chief Executive Officer, Mr. Colborne subscribed for an aggregate of $2.5 million in units of the Corporation at a price of $3.57 per unit. Each unit was comprised of one Common Share and two Common Share purchase warrants with each such warrant entitling the holder thereof to purchase one Common Share at $4.46 for a period of five years, subject to vesting based on both time and the performance of the Common Shares. With respect to time vesting, the warrants vest as to 1/3 on each of the first three anniversaries of the issuance date. With respect to performance vesting, the warrants vest as to 1/2 when the market price of the Common Shares (calculated using the volume weighted average trading price of the Common Shares for the preceding 20 trading days) reaches $6.30, and 1/2 when the market price reaches $8.40. Both the time and performance vesting criteria must occur before any warrants vest. The warrants are non-transferable, except to certain permitted transferees, all as approved by the Board.

North Dakota Disposition

On May 31, 2013, the Corporation completed the sale of certain non-core, primarily non-operated assets in North Dakota through the sale of all of the issued and outstanding shares of its previously wholly-owned subsidiary, Surge Energy USA Inc., for gross proceeds of US$42.7 million. The assets of Surge Energy USA Inc. consisted of production of approximately 650 boe/d, with independently engineered proved plus probable reserves of 2.2 million boe, and a net present value of US$36.8 million (discounted at ten percent before tax as of December 31, 2012).

Cenovus Asset Acquisition and Financing

On July 3, 2013, the Corporation completed the acquisition of certain petroleum and natural gas properties and related assets in southwest Saskatchewan from Cenovus Energy Inc. for total consideration of $242.4 million (the "**Cenovus Asset Acquisition**"). The acquired assets are located in southwest Saskatchewan, approximately 100 kilometres southwest of Swift Current, Saskatchewan, 140 kilometres east of the Alberta border. The assets include an average working interest of approximately 98% in 14,485 gross (14,196 net) acres of undeveloped land as at April 1, 2013. Production from the assets was weighted 100% to medium crude oil and natural gas liquids. The property also included 134 gross (133 net) producing oil wells and 49 gross (49 net) non-producing oil wells as at April 1, 2013. Major facilities included a battery at 1-15-6-19-W3 that has capacity of 15,000 barrels of emulsion per day and 10 MMcf of gas per day, five tanks that have capacity for 5,000 barrels each, a free water knockout, a water treater and disposal water pumps. The assets consisted of production of approximately 3,468 boe/d (average production volume for the three months ended September 30, 2013), with independently engineered net proved plus probable reserves of 10.2 million boe, and a net present value of $223 million (discounted at ten percent before tax as of April 1, 2013).

Concurrently with the Cenovus Asset Acquisition, on July 3, 2013, the Corporation also completed a $247,500,000 "bought deal" unit financing by short form prospectus pursuant to which the Corporation issued an aggregate of 15,000,000 units at a price of $15.00 per unit and an additional 4,500,000 subscription receipts at a price of $5.00 per subscription receipt pursuant to the exercise of the underwriters' option. Each unit was comprised of one Common Share and two subscription receipts. Each subscription receipt converted into one Common Share upon completion of the Cenovus Asset Acquisition.

Flagstone Acquisition and Fort Calgary Asset Acquisition

On November 13, 2013, the Corporation completed: (i) the acquisition of all of the issued and outstanding shares of Flagstone Energy Inc. (the "**Flagstone Acquisition**"); and (ii) the acquisition of certain petroleum and natural gas properties and related assets in southwest Manitoba from 1779275 Alberta Ltd. and Fort Calgary Resources Ltd. (the "**Fort Calgary Asset Acquisition**").

The Flagstone Acquisition involved a $147 million (based on a Surge share price of $6.00 per Common Share) purchase of all of the issued and outstanding shares of Flagstone Energy Inc., a Calgary based private oil and gas company with high netback, operated, producing light oil assets focused in the Steelman area of southeast Saskatchewan and the Dodsland area of southwest Saskatchewan. The consideration for the Flagstone Acquisition was comprised of 20.2 million Common Shares and cash consideration of $3.0 million, plus the assumption of $23 million of debt.

The Fort Calgary Asset Acquisition involved the acquisition by the Corporation of high quality, high netback, operated, producing light oil assets primarily located in the southwest area of Manitoba for total consideration of $135 million (based on a Surge share price of $6.00 per Common Share), comprised of 14.2 million Common Shares and $50 million of cash.

Wainwright Asset Acquisition and Financing

On December 3, 2013, the Corporation completed the acquisition of certain oil and gas assets located in the Wainwright area of central Alberta from a Calgary based company for consideration of $76.8 million in cash (the "**Wainwright Acquisition**"). The assets included an average working interest of 80% in approximately 24,054 gross (19,252 net) acres of developed land and 64% in approximately 5,107 gross (3,291 net) acres of undeveloped land as at November 5, 2013. Production from the assets was weighted 98% to medium crude oil (23° API) and included key producing infrastructure, including batteries, pipelines, and water flood facilities.

On November 28, 2013, just prior to the Wainwright Asset Acquisition, the Corporation completed a $63,273,000 "bought deal" subscription receipt financing by short form prospectus pursuant to which the Corporation issued an aggregate of 9,660,000 subscription receipts at a price of $6.55 per subscription receipt (including the exercise of the underwriters' option). Each subscription receipt converted into one Common Share upon the completion of the Wainwright Asset Acquisition.

Year ended December 31, *2014*

Renegade Asset Acquisition and Financing

On February 14, 2014, the Corporation acquired certain petroleum and natural gas properties and related assets in southeast Saskatchewan for consideration of $109 million in cash (the "**Renegade Asset Acquisition**"). The assets included an average working interest of approximately 83% in 14,735 gross (12,226 net) acres of undeveloped land as at January 13, 2014, with an internally estimated value of $3 million. Production from the assets was weighted 97% to light crude oil (36° API). The assets also included key producing infrastructure, including batteries, pipelines, and water flood facilities.

On February 4, 2014, just prior to the Renegade Asset Acquisition, the Corporation completed a $80,506,440 "bought deal" subscription receipt financing by short form prospectus pursuant to which the Corporation issued an aggregate of 12,778,800 subscription receipts at a price of $6.30 per subscription receipt (including the exercise of the underwriters' option). Each subscription receipt converted into one Common Share upon the completion of the Renegade Asset Acquisition.

Longview Acquisition

On February 28, 2014, Surge acquired 9.3 million shares in the capital of Longview Oil Corp. ("**Longview**"), representing 19.8 percent of the issued and outstanding shares of Longview, at a purchase price of $4.45 per share pursuant to a bought deal secondary offering of the shares of Longview.

On June 5, 2014, Surge completed the acquisition of all of the remaining issued and outstanding shares of Longview by plan of arrangement (the "**Longview Acquisition**"). Under the Longview Acquisition, shareholders of Longview, other than Surge, received 0.975 Common Shares in exchange for each share of Longview held. Surge issued an aggregate of 37,975,332 Common Shares (at a deemed price of $6.14 per Common Share) pursuant to the Longview Acquisition and assumed approximately $155 million of Longview net debt, implying a transaction value, including the shares of Longview purchased on February 28, 2014, of approximately $430 million. The Longview Acquisition included production, as at June 5, 2014, of approximately 5,700 boe/d (80 percent oil and NGLs), proven and probable reserves, as at December 31, 2013, of approximately 37.6 million boe (80 percent oil and NGLs) and approximately 143,600 net acres of undeveloped lands.

Year ended December 31, *2015*

SE Saskatchewan and Manitoba Disposition

On June 15, 2015, the Corporation completed the disposition of certain oil and gas assets in SE Saskatchewan for cash consideration of $430 million. The sold assets comprised of approximately 4,750 boe/d of production at the time of disposition and approximately 23 million boe of proved plus probable reserves. The assets also included an average working interest of approximately 76% in 142,945 gross (109,321 net) acres of undeveloped land including Fee acreage as at the time of disposition, 2015, with an internally estimated value of $137 million. Production from the assets was weighted 95% to light crude oil (30° API). The properties involved were Macoun, Pinto and Alida in Saskatchewan and Manson in Manitoba.

DESCRIPTION OF THE BUSINESS

Overview

The Corporation is a moderate growth, dividend paying oil and gas exploration, development and production company. Surge holds focused and operated high quality light and medium gravity crude oil properties, primarily in Alberta and Saskatchewan, 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 is building a moderate growth, dividend paying oil and gas company with focused, operated light and medium gravity crude oil assets. 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 of the Corporation believes in controlling the timing and costs of its 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: (i) risk capital to secure or evaluate the opportunity; (ii) the potential return on the project, if successful; (iii) the likelihood of success; and (iv) 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 currently 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 wellsites in compliance with applicable environmental laws and regulations. As of December 31, 2015, the Corporation has recorded an asset retirement obligation of $130 million. The Corporation anticipates that the expenditures necessary to satisfy the asset retirement obligation will be incurred over a period of fifty years, with the majority of the expenditures being incurred from years 2025 to 2064. 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 and Other Oil and Gas Information – Other Oil and Gas Information – Forward Contracts*". For details of the Corporation's forward contracts in place as at December 31, 2015, see the Corporation's audited annual financial statements for the year ended December 31, 2015, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com . See "*Risk Factors*".

Personnel

As at December 31, 2015, the Corporation had 61 head office employees and 4 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.

PRINCIPAL PRODUCING PROPERTIES

The Corporation's principal oil and natural gas producing properties are located in Alberta and Saskatchewan and are focused across three core areas: Western Alberta, Southeast Alberta and Southwest Saskatchewan. A description of those properties, as at December 31, 2015, is provided below.

Western Alberta

As at December 31, 2015, the Corporation's principal properties in Western Alberta included Valhalla/Wembley, Nipisi, Windfall and Nevis. Surge held an average working interest of approximately 69% in approximately 194,041 gross (134,336 net) developed acres. As at December 31, 2015, the Corporation held interests in 443 gross (228 net) oil wells and 119 gross (49 net) gas wells producing from, but not limited to, the Doe Creek, Doig, Montney, Slave Point, Gilwood, Banff, Wabamun, Rock Creek, Glauc, and Bluesky formations. In addition, the Corporation operates multiple oil batteries and an oil blending facility, providing a strong infrastructure base for future development in the area. As at December 31, 2015, Surge's production in Western Alberta was approximately 8,107 boe/d (67 percent oil and NGLs).

Valhalla/Wembley

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 new horizontal oil wells producing from an extensive tight sand, with up to 50 metres of gross light oil pay in the Triassic Doig formation. Additional production is from a shallow, waterflooded, Doe Creek light oil pool.

In 2015, the Corporation drilled 3 gross (3 net) Doig horizontal, multi-frac oil wells at Valhalla. Also in 2015, the Corporation installed additional gathering and compression facilities to direct the majority of solution gas produced from the Doig oil pool to a sweet gas processing facility where firm capacity was obtained.

Nipisi

The Nipisi property is located approximately 50 kilometres north of the town of Slave Lake, in northwestern Alberta. Light oil production is from the Slave Point and Gilwood formations. The Slave Point production is from horizontal, multi-frac wells and the Gilwood production is from vertical wells.

In 2015 the Corporation continued to optimize its Slave Lake oil pool, including the waterflood on this property, which had been implemented in 2013 and 2014, with the conversion of 3 wells to injection wells. Successful incremental waterflood response has been accomplished in 2015.

Windfall

The Windfall property is located in western Alberta near Whitecourt. Production from this property is derived from horizontal multi-frac wells and vertical Bluesky formation wells. A waterflood pilot, originally implemented in 2012, has demonstrated positive results in terms of stabilizing reservoir pressure and flattening the decline of the offset producing horizontal wells.

Nevis

The Nevis property is located approximately 60 kilometres east of Red Deer, Alberta. The Nevis property was acquired pursuant to the Corporation's acquisition of Longview Oil Corp. in 2013. The property is divided into two main Wabamun oil pools. Crude oil quality for this property averages 39° API and there is associated natural gas and NGL production. Two operated facilities are utilized to process the oil and natural gas production from Nevis. The main producing zone is the Devonian age Wabamun Formation, which occurs at about 1,600 metres true vertical depth. This reservoir is a high porosity, low permeability carbonate which results in relatively low production inflow from vertical wells.

Southeast Alberta

As at December 31, 2015, Surge's principal properties in southeastern Alberta included the Sparky assets and the Lloyd/Cummings zone waterflood at Silver. The Corporation held an average working interest of approximately 79% in approximately 148,766 gross (117,395 net) developed acres and an average working interest of approximately 86% in approximately 50,386 gross (43,179 net) undeveloped acres. As at December 31, 2015, the Corporation held interests in 427 gross (289 net) oil wells and 188 gross (84 net) gas wells producing from, but not limited to, the Lloydminster, Sparky, Cummings, Glauconite, Rex, Dina and Viking formations. In addition, the Corporation operates multiple oil batteries and an oil blending facility, providing a strong infrastructure base for future development in the area. As at December 31, 2015, Surge's production in Southeast Alberta was approximately 3,559 boe/d (88 percent oil and NGLs).

Sparky

The Sparky assets are comprised of four main fields spread between Provost and Wainwright in eastern Alberta and western Saskatchewan. Eye Hill and Provost are early stage primary development properties, while Wainwright and Macklin are far more mature, mostly developed waterflood assets.

In 2015, the Corporation initiated and expanded a horizontal waterflood pilot project at Eyehill, after observing successful waterflood response. In 2015, the Corporation drilled 3 (100% working interest) horizontal, multi-frac, Sparky oil wells and converted a second horizontal well to injection at Eyehill.

Production from the Sparky is primarily crude oil (89 percent oil and NGLs) ranging from 23° to 28° degrees API.

Silver

The Silver Lake property is located west of Provost in eastern Alberta. Production from this property is primarily 24° API Crude oil from the Lloydminster and Cummings formations. The field has been developed by a mixture of horizontal and vertical wells and is extensively under waterflood.

Southwest Saskatchewan

The Southwest Saskatchewan properties, the majority of which were acquired in July 2013, are primarily located approximately 100 kilometres southwest of Swift Current, Saskatchewan and 140 kilometres east of the Alberta border. As at December 31, 2015, this operated property included an average working interest of approximately 99% in approximately 21,987 gross (21,672 net) developed acres and an average working interest of approximately 98% in 13,032 gross (12,712 net) undeveloped acres. The Corporation's production from this property is weighted 100% to medium crude oil (21-26° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. As at December 31, 2015, this property produced approximately 2,521 boe/d (100 percent oil and NGLs) from the Upper and Lower Shaunavon formations.

In 2015, the Corporation continued the development and delineation of the extensive Upper Shaunavon pool, with the drilling of 9 horizontal, multi-frac, oil wells. The Corporation also initiated a horizontal, waterflood Pilot in Upper Shaunavon, with the conversion of 2 producing wells to water injection.

In February of 2015, the Corporation divested its non-core, Viking oil producing assets in the Dodsland Area for proceeds of $35.6 million representing a producing barrel metric of $75,000 per boe/d.

STATEMENT OF RESERVES DATA

In accordance with NI 51-101 – *Standards for Disclosure for Oil and Gas Activities*, 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, 2015. The Reserves Report is dated February 3, 2016.

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	12,878.8	9,780.0	1,462.1	35,298.4	1,070.2	10,713.7	9,192.0	1,014.5	31,847.2	1,029.4
Developed Non-Producing	559.6	438.9	116.3	3,288.8	-	457.8	429.2	81.7	2,849.9	-
Undeveloped	8,970.0	4,837.7	1,296.2	33,372.8	1,581.5	7,280.6	4,630.3	949.8	30,216.0	1,488.9
Total Proved	**22,408.4**	**15,056.6**	**2,874.6**	**71,960.0**	**2,651.7**	**18,452.1**	**14,251.6**	**2,046.0**	**64,913.2**	**2,518.3**
Probable	**14,809.6**	**10,223.0**	**1,526.7**	**38,179.1**	**866.0**	**11,118.6**	**9,467.0**	**1,071.6**	**33,159.0**	**824.1**
Total Proved plus Probable	**37,217.9**	**25,279.7**	**4,401.2**	**110,139.1**	**3,517.7**	**29,570.7**	**23,718.6**	**3,117.6**	**98,072.2**	**3,342.4**

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

	Before Future Income Tax Expenses and Discounted at				
($M)	0%	5%	10%	15%	20%
Proved					
Developed Producing	839,764	617,465	489,636	406,465	348,017
Developed Non-Producing	38,563	31,004	25,435	21,251	18,040
Undeveloped	446,255	296,273	202,178	140,885	99,408
Total Proved	**1,324,583**	**944,742**	**717,249**	**568,601**	**465,465**
Probable	**1,166,187**	**647,234**	**420,354**	**297,120**	**221,488**
Total Proved plus Probable	**2,490,770**	**1,591,976**	**1,137,603**	**865,721**	**686,953**

	After Future Income Tax Expenses and Discounted at				
($M)	0%	5%	10%	15%	20%
Proved					
Developed Producing	839,764	617,465	489,636	406,465	348,017
Developed Non-Producing	38,563	31,004	25,435	21,251	18,040
Undeveloped	355,964	240,969	166,658	117,166	83,049
Total Proved	**1,234,291**	**889,438**	**681,729**	**544,882**	**449,106**
Probable	**852,874**	**471,845**	**305,749**	**215,899**	**160,988**
Total Proved plus Probable	**2,087,166**	**1,361,283**	**987,478**	**760,781**	**610,094**

	Unit Value before Income Tax Discounted at 10%/year ($/boe)
Proved	
Developed Producing	18.55
Developed Non-Producing	17.62
Undeveloped	11.14
Total Proved	**15.60**
Probable	**15.39**
Total Proved plus Probable	**15.52**

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	3,395,118	446,105	1,243,605	316,636	64,189	1,324,583	90,291	1,234,291
tal Proved plus Probable	5,989,173	898,489	2,040,121	486,163	73,629	2,490,770	403,604	2,087,166

Future Net Revenue by Production Group – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes and Discounted at 10% ($M)	Per Unit Future Net Revenue Before Income Taxes and Discounted at 10%(3) ($/boe)
Proved		
Light and Medium Crude Oil(1)	441,457	15.04
Heavy Crude Oil	262,948	18.22
Conventional Natural Gas(2)	11,515	6.44
Coalbed Methane	1,328	3.14
Proved plus Probable		
Light and Medium Crude Oil(1)	687,091	14.87
Heavy Crude Oil	434,012	18.11
Conventional Natural Gas(2)	14,637	5.67
Coalbed Methane	1,863	3.32

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, 2015 in its evaluation in estimating reserves data using forecast prices and costs. The weighted average historical prices received by the Corporation for 2015 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)
2015 (Surge Actual)	57.45	46.09	2.70	61.45	36.81	6.17	1.4	-19.7	0.783
2016	55.20	45.26	2.25	59.10	39.09	9.09	0.0	0.0	0.750
2017	69.00	57.96	2.95	73.88	51.43	13.64	0.0	4.0	0.800
2018	78.43	65.88	3.42	83.98	58.46	25.84	1.5	4.0	0.830
2019	89.41	75.11	3.91	95.73	66.64	35.35	1.5	4.0	0.850
2020	91.71	77.03	4.20	98.19	68.35	42.30	1.5	1.5	0.850
2021	93.08	78.19	4.28	99.66	69.38	42.94	1.5	1.5	0.850
2022	94.48	79.36	4.35	101.16	70.42	43.58	1.5	1.5	0.850
2023	95.90	80.55	4.43	102.68	71.48	44.24	1.5	1.5	0.850
2024	97.34	81.76	4.51	104.22	72.55	44.90	1.5	1.5	0.850
2025	98.80	82.99	4.59	105.78	73.64	45.57	1.5	1.5	0.850
2026	100.28	84.23	4.67	107.37	74.74	46.26	1.5	1.5	0.850

Escalated thereafter at a rate of +1.5% 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, 2015, derived from the Reserves Report using forecast prices and cost estimates, reconciled to the gross reserves of the Corporation as at December 31, 2015.

	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, 2014	41,997	8,897	3,325	84,639	-	68,326
Product Type Transfer	(4,471)	4,471	-	(2,944)	2,944	-
Extensions and Improved Recovery	2,356	1,609	337	10,301	-	6,019
Technical Revisions	683	1,691	(92)	(6,986)	(13)	1,116
Acquisitions	-	105	-	146	-	129
Dispositions	(14,095)	-	(184)	(2,189)	-	(14,644)
Economic Factors	(764)	(296)	(257)	(4,820)	(130)	(2,142)
Production	(3,297)	(1,420)	(255)	(6,187)	(150)	(6,028)
Balance at December 31, 2015	**22,408**	**15,057**	**2,875**	**71,960**	**2,652**	**52,775**

	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, 2014	29,366	4,890	1,762	46,156	-	43,711
Product Type Transfer	(4,567)	4,567	-	(927)	927	-
Extensions and Improved Recovery	1,571	2,123	214	6,779	-	5,037
Technical Revisions	(1,869)	(1,240)	(420)	(13,595)	38	(5,788)
Acquisitions	90	(90)	-	56	-	10
Dispositions	(9,915)	-	(111)	(1,217)	-	(10,229)
Economic Factors	134	(28)	82	926	(99)	326
Production	-	-	-	-	-	-
Balance at December 31, 2015	**14,810**	**10,223**	**1,527**	**38,179**	**866**	**33,067**

	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, 2014	71,362	13,787	5,088	130,795	-	112,036
Product Type Transfer	(9,039)	9,039	-	(3,871)	3,871	-
Extensions and Improved Recovery	3,927	3,732	551	17,080	-	11,056
Technical Revisions	(1,186)	452	(512)	(20,580)	25	(4,672)
Acquisitions	90	15	-	202	-	139
Dispositions	(24,010)	-	(295)	(3,406)	-	(24,873)
Economic Factors	(630)	(324)	(175)	(3,894)	(228)	(1,817)
Production	(3,297)	(1,420)	(255)	(6,187)	(150)	(6,028)
Balance at December 31, 2015	**37,218**	**25,280**	**4,401**	**110,139**	**3,518**	**85,842**

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were first attributed in each of the four most recent financial years and, in the aggregate, before that time:

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)
Proved				
Prior to 2011	1,898.5	424.2	302.3	10,984.9
2011	3,343.7	302.3	721.5	19,281.0
2012	2,955.3	1,191.3	306.6	8,393.0
2013	6,215.5	366.1	574.8	15,195.3
2014	4,713.0	166.1	268.3	5,100.0
2015	1,542.3	1,199.2	274.5	8,011.0

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of the four most recent financial years and, in the aggregate, before that time:

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)
Probable				
Prior to 2011	2,244.4	521.8	311.5	13,600.3
2011	2,269.7	161.2	398.0	11,128.0
2012	6,703.2	457.2	197.8	5,731.0
2013	9,567.4	196.5	350.5	9,370.2
2014	8,526.4	71.1	274.0	5,586.0
2015	1,241.6	1,948.1	188.6	5,577.0

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)**
2016	14,958	18,557
2017	92,893	128,380
2018	104,563	144,820
2019	70,247	117,791
2020	33,975	75,663
Remaining Years	-	952
Total Undiscounted	**316,636**	**486,163**

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 Reserve Reports or either of them. 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, 2015.

	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	774	577	174	118	26	17	214	143	1026	806	291	201	-	-	122	96
Saskatchewan	157	155	67	4	-	-	15	15	44	44	26	8	-	-	4	4
Total	**931**	**732**	**241**	**122**	**26**	**17**	**229**	**158**	**1070**	**850**	**317**	**209**	**-**	**-**	**126**	**100**

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2015, 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	174,557	147,332	11,456
Saskatchewan	9,398	7,458	–
Total	**183,955**	**154,790**	**11,456**

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 763.6 net wells under the proved reserves category is $64.2 million undiscounted ($13.5 million discounted at 10%), of which a total of nil is estimated to be incurred in 2016, 2017 and 2018. This estimate does not include expected reclamation costs for surface leases. 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. Ongoing environmental obligations are expected to be funded out of cash flow.

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 2020.

Costs Incurred

The following table summarizes capital expenditures incurred by the Corporation during the year ended December 31, 2015.

	Property Acquisition Costs				
	Proved Properties	Unproved Properties	Property Dispositions	Exploration Costs	Development Costs
Total ($M)	5,217	–	(468,785)	–	76,731

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, 2015.

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	–	–	18.00	15.60
Heavy Crude Oil	–	–	–	–
Conventional Natural Gas	–	–	–	–
Service	–	–	–	–
Dry	–	–	–	–
Total	**–**	**–**	**18.00**	**15.60**

Planned Capital Expenditures

The Corporation has announced a planned capital expenditure budget of approximately $50 million for 2016.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Reserves Report for 2015 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							
Southwest Saskatchewan	-	2,107	-	-	-	2,107	17%
Southeast Alberta	1,684	1,183	1,715	-	42	3,194	26%
Western Alberta	3,771	72	14,602	370	607	6,945	57%
Total Proved	**5,454**	**3,362**	**16,317**	**370**	**649**	**12,246**	**100%**
Proved Plus Probable							
Southwest Saskatchewan	-	2,370	-	-	-	2,370	18%
Southeast Alberta	1,783	1,223	1,953	-	46	3,377	26%
Western Alberta	4,016	81	15,797	376	646	7,440	56%
Total Proved Plus Probable	**5,799**	**3,674**	**17,749**	**376**	**693**	**13,187**	**100%**

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2015, certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the Corporation.

Average Daily Production Volume

	Three Months Ended			
	Mar 31, 2015	**Jun 30, 2015**	**Sep 30, 2015**	**Dec 31, 2015**
Conventional Natural Gas (Mcf/d)	20,015	16,269	13,273	18,038
Light and Medium Crude Oil (bbls/d)	16,296	14,345	10,635	10,297
NGL (bbls/d)	875	520	599	795
Coalbed Methane (Mcf/d)	469	455	458	532
Total (boe/d)	**20,585**	**17,652**	**13,523**	**14,187**

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

	Three Months Ended			
($ per Bbl)	**Mar 31, 2015**	**Jun 30, 2015**	**Sep 30, 2015**	**Dec 31, 2015**
Prices Received	37.60	49.99	36.41	31.06
Royalties Paid	(5.72)	(7.36)	(6.48)	(5.96)
Production Costs	(17.36)	(14.65)	(13.03)	(12.28)
Transportation Costs	(1.33)	(1.40)	(2.07)	(1.75)
Netback[(1)]	**13.19**	**26.58**	**14.84**	**11.07**

Note:

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

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

($ per Mcf)	Three Months Ended Mar 31, 2015	Jun 30, 2015	Sep 30, 2015	Dec 31, 2015
Prices Received	2.25	2.08	2.34	1.88
Royalties Paid	(0.07)	0.37	0.03	0.40
Production Costs	(2.54)	(2.87)	(1.92)	(1.74)
Transportation Costs	(0.46)	(0.33)	1.01	–
Netback	**(0.83)**	**(0.74)**	**1.46**	**0.54**

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

($ per boe)	Three Months Ended Mar 31, 2015	Jun 30, 2015	Sep 30, 2015	Dec 31, 2015
Prices Received	37.97	50.34	36.80	31.37
Royalties Paid	(5.73)	(7.30)	(6.47)	(5.89)
Production Costs	(17.78)	(15.13)	(13.35)	(12.57)
Transportation Costs	(1.41)	(1.45)	(1.90)	(1.75)
Netback[(1)]	**13.05**	**26.46**	**15.08**	**11.16**

Note:

1. 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, 2015.

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)	%
Western Alberta	4,878	14,160	650	479	7,967	48%
Southeast Alberta	3,180	2,472	42	-	3,634	22%
Southwest Saskatchewan	2,491	-	-	-	2,491	15%
Southeast Saskatchewan and Viking[(1)]	2,322	252	6	-	2,370	14%
Total	**12,871**	**16,883**	**697**	**479**	**16,462**	**100%**

Note:

1. Southeast Saskatchewan and Viking properties were divested during 2015.

DESCRIPTION OF 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.

DIVIDEND POLICY

On July 3, 2013, in connection with the Corporation's transition to a sustainable, moderate growth, dividend paying oil and gas company, the Board adopted a policy of paying monthly dividends, initially at a rate of $0.40 per annum ($0.0333 monthly).

On August 7, 2013, the Board approved an increase of the dividend to $0.42 per annum ($0.035 monthly). On October 22, 2013, pursuant to the Saskatchewan and Manitoba acquisitions, the Board approved a further increase of the dividend to $0.50 per annum ($0.04166 monthly). On November 6, 2013, pursuant to the Wainwright Acquisition, the Board approved a further increase of the dividend to $0.52 per annum ($0.04333 monthly). On January 13, 2014, pursuant to the SE Saskatchewan Asset Acquisition, the Board approved a further increase of the dividend to $0.54 per annum ($0.045 monthly). On June 5, 2014, pursuant to the Longview Acquisition, the Board approved a further increase of the dividend to $0.60 per annum ($0.05 monthly).

On January 7, 2015, as a result of the precipitous drop in crude oil prices from US$106 WTI per barrel in June 2014 to a low of US$45 WTI in January 2015, the Board approved a reduction of the dividend to $0.30 per annum ($0.025 monthly). On November 9, 2015, as a result of the continued weakness of crude oil prices, the Board approved a further reduction of the dividend to $0.15 per annum ($0.0125 monthly).

The primary objective of the Corporation's dividend policy is to provide shareholders with relatively stable, predictable and sustainable monthly dividends.

The agreement with respect to the Credit Facility contains certain restrictions on Surge's ability to pay dividends in certain circumstances. 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 for the periods indicated:

	Dividends per Common Share		
Month	**2016**	**2015**	**2014**
January	0.0125	0.025	$0.04333
February	0.0125	0.025	$0.04333
March	0.0125	0.025	$0.045
April		0.025	$0.045
May		0.025	$0.045
June		0.025	$0.05
July		0.025	$0.05
August		0.025	$0.05
September		0.025	$0.05
October		0.025	$0.05
November		0.0125	$0.05
December		0.0125	$0.05
Total	$0.0375	$0.275	$0.57166

Unless otherwise specified, all dividends paid or to be paid are designated as "eligible dividends" under the *Income Tax Act* (Canada).

There can be no guarantee that the Corporation will maintain its dividend policy. The amount of cash dividends to be paid on the Common Shares, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including the 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. Additionally, the agreement with respect to the Credit Facility contains certain restrictions on Surge's ability to pay dividends in certain circumstances. See "*Risk Factors – Dividends*".

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, 2015.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
2015			
January	3.86	2.23	63,009,587
February	3.60	2.57	63,679,397
March	3.39	2.55	33,991,372
April	4.45	2.88	49,256,039
May	4.57	3.95	32,251,962
June	4.105	3.51	34,868,182
July	3.55	2.13	37,942,447
August	3.14	1.99	48,614,179
September	2.98	2.43	35,384,091
October	3.715	2.71	53,884,479
November	3.26	2.39	42,411,604
December	2.55	1.85	37,243,306

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 Calgary, Alberta	President and Chief Executive Officer Director since April 13, 2010	President and CEO of the Corporation. He is also the President of StarValley Oil and Gas Ltd., a private, Calgary-based oil and gas company founded in November 2005. Mr. Colborne currently serves on the Board of Directors of Red River Oil Inc., 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., which grew to a 15,000 boe/d, publicly traded company. Eight years later in 2001, Startech was acquired by ARC Energy Trust for more than C$500 million. From September 2003 to January 2005, Mr. Colborne was the President and CEO of StarPoint Energy Trust, a 36,000 boe/d publicly traded energy trust. From 1996 to May of 2013, Mr. Colborne was on the Board of Crescent Point Energy, a 140,000 boe/d, publicly traded, dividend paying oil and gas company. Until its sale in July of 2009, Mr. Colborne served as Chairman of TriStar Oil & Gas Ltd. He was also a Director for Westfire Energy Ltd., Twin Butte Energy Ltd., Cequence Energy, and Chairman of Seaview Energy Ltd. until its sale in December of 2009, he also served as a Director of Breaker Energy. Mr. Colborne was also Chairman and a Director of Mission Oil and Gas Inc. until its sale in February 2007. In May of 2014, Paul stepped down from the Board of Legacy Oil + Gas. In June of 2014, Paul completed his term as Chairman of New Star Energy, and stepped down as a Director.
P. Daniel O'Neil(3)(4) Calgary, Alberta	Director since April 13, 2010	Independent businessperson since his retirement on May 8, 2013. Prior thereto, President and Chief Executive Officer of the Corporation since April 13, 2010. Prior thereto, 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 its sale, Mr. O'Neil was also a director of Hyperion Exploration Corp.
Robert Leach(1)(2) Calgary, Alberta	Director since April 13, 2010	Chief Executive Officer of Custom Truck Sales Ltd., a private company operating Kenworth truck dealerships in Saskatchewan and Manitoba, and CEO of International Fitness Holdings, an operating arm of a private equity firm operating health clubs in Alberta. Mr. Leach was formerly the Chairman of the Board of Breaker Energy Inc.
Keith Macdonald(1)(3)(4) Calgary, Alberta	Director since April 13, 2010	President of Bamako Investment Management Ltd., a private holding and financial consulting company. Mr. Macdonald is also a director of Bellatrix Exploration Ltd., a company listed on the TSX. As well, he is a director of Madalena Energy Inc. and Mountainview Energy Ltd., which are listed on the TSX Venture Exchange, and other public and private oil and gas companies. Mr. Macdonald has

Name and Residence	Position	Principal Occupation During Previous Five Years
		served as an officer and director of a number of public and private energy companies.
James Pasieka Calgary, Alberta	Director since April 13, 2010 Chairman of the Board since January 7, 2015	Partner of the national law firm McCarthy Tétrault LLP since September 2013. Prior thereto, partner of the national law firm Heenan Blaikie LLP since 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.
Murray Smith[(1)(2)] Calgary, Alberta	Director since June 25, 2010	President of Murray Smith and Associates and Williams Companies Inc. Mr. Smith also serves on the board of two private companies. Prior thereto, Mr. Smith was an Official Representative of the Province of Alberta to the United States of America until 2007. Prior thereto, he 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.
Colin Davies[(3)(4)] Calgary, Alberta	Director since July 9, 2010	President & CEO of Corinthian Oil Corp. since November 2014, and prior thereto, President & CEO of Corinthian Exploration Corp., a private oil and gas company with assets located in the USA and Canada. Prior thereto, Mr. Davies was President & CEO of Corinthian Energy Corp., a private oil and gas company that was founded in 2004 and amalgamated with Surge Energy Inc. in July 2010. Mr. Davies is a professional engineer with over twenty five years of diverse experience in the oil and gas industry.
Daryl Gilbert[(2)(3)] Calgary, Alberta	Director since June 5, 2014	Managing Director and Investment Committee member of 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.
Paul Ferguson Calgary, Alberta	Chief Financial Officer	Chief Financial Officer of the Corporation since September 2015. Prior thereto, Mr. Ferguson was a research analyst at Fidelity Investments from December 2012. Prior thereto, Mr. Ferguson was a research analyst at Surveyor Capital from May 2011 to December 2012. Prior thereto, Mr. Ferguson was a portfolio manager and analyst at Swank Capital, LLC.

Name and Residence	Position	Principal Occupation During Previous Five Years
Dan Brown Calgary, Alberta	Chief Operating Officer	Chief Operating Officer of the Corporation. Prior thereto, Chief Operating Officer of Breaker Energy Ltd. from August 2009 until its acquisition by NAL Oil & Gas Trust in December 2009. Prior thereto, Mr. Brown was the Business Unit Team Lead at a major North American production company.
Margaret Elekes Calgary, Alberta	Vice-President, Land	Vice-President, Land of the Corporation. Prior thereto, Consulting Landman for Breaker Energy from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009. Prior thereto, US Land Manager for Upton Resources from December 1995 until its acquisition by StarPoint Energy in February 2004.
Murray Bye Calgary, Alberta	Vice-President, Production	Vice-President, Production of the Corporation since May 8, 2013. Prior thereto, Asset Team Lead - West at Surge since 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.
Gerry de Leeuw Calgary, Alberta	Vice-President, Geosciences	Vice-President, Geosciences of the Corporation. Gerry de Leeuw is a Professional Geologist with over 25 years of experience in the oil and gas industry focused in the Western Canadian Sedimentary basin. Over the past ten years, Gerry has served in a variety of senior executive roles with Devon Canada with his longest and most recent role as V.P. of Exploration and Development. Previous to Devon, he worked at a number of companies including; Northstar, TCPI, Amoco and Texaco where he gained experience through increasingly senior technical and management positions.
Rod Monden Calgary, Alberta	Controller	Controller of the Corporation. Prior thereto, Controller for Breaker Energy Ltd. from January 2008 until its acquisition by NAL Oil & Gas Trust in December 2009. Prior thereto, VP Finance and CFO of a private junior oil and gas company from September 2006 to October 2008. Prior thereto, Mr. Monden worked as Manager, Financial Reporting & Budgets at Burlington Resources Canada Ltd. from September 2002 to August 2006.

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 a group, the directors and executive officers of the Corporation beneficially own, control or direct, directly or indirectly, 6,695,025 Common Shares, representing approximately 3.0 percent of the outstanding Common Shares as at March 16, 2016.

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 Globel Direct Inc ("**Globel Direct**") which sought and received protection under the *Companies' Creditors Arrangement Act* (Canada) in June 2007, and after a failed restructuring effort, a receiver was appointed by one of Globel Direct's lenders in December 2007. Cease trade orders dated September 24, 2008 and September 30, 2008 were issued by the Alberta Securities Commission and the British Columbia Securities Commission, respectively, for failure to file financial statements. The cease trade orders were issued following the appointment of the receiver and, as at the date hereof, have not been revoked.

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 Keith Macdonald (Chair), Murray Smith and Robert Leach. 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
Keith Macdonald	✓	✓	Mr. Macdonald is currently the President of Bamako Investment Management Ltd., a private holding and financial consulting company. Mr. Macdonald is a director of Bellatrix Exploration Ltd., Madalena Energy Inc., and Mountainview Energy Ltd. He has served as chair and/or a member of the audit committee of each of those companies, as well as several other public oil and gas companies for which he has been a director. Mr. Macdonald was also formerly a director of Breaker Energy Ltd. prior to its sale in 2009. From 1994 to January 1999, Mr. Macdonald was vice president of finance and a director of New Cache Petroleum Ltd. Mr. Macdonald founded New Cache Petroleum Ltd. in 1988 and was its president until a merger in 1994. Mr. Macdonald holds the Chartered Accountants designation, achieved in 1980, and a Bachelor of Commerce degree (Accounting and Finance Major) from University of Calgary in 1978.
Murray Smith	✓	✓	President of Murray Smith and Associates and Williams Companies Inc. Mr. Smith also serves on the board of two private companies. Prior thereto, Mr. Smith was an Official Representative of the Province of Alberta to the United States of America until 2007. Prior thereto, he 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. From 1998-2004 Mr. Smith was a member of the Government of Alberta Treasury Board (responsible for the annual budget for Alberta) and a contributing member to Alberta's debt elimination in 2004. Mr. Smith has a degree in Economics from the University of Calgary (1971) and is a graduate of the London Business School Senior Executive Program (2000).

Name	Independent	Financially Literate	Relevant Education and Experience
Robert Leach	✓	✓	Mr. Leach is currently the Chief Executive Officer of Custom Truck Sales Ltd., a private company operating Kenworth truck dealerships in Saskatchewan and Manitoba, and CEO of International Fitness Holdings, an operating arm of a private equity firm operating health clubs in Alberta. Mr. Leach was formerly the Chairman of the Board of Breaker Energy Inc. 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. Mr. Leach holds a Bachelor of Commerce from the College of Commerce at the University of Saskatchewan where he majored in Accounting (1982). Mr. Leach articled with KPMG LLP and left to start a private business in 1983.

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
2015	$255,000	$53,500	$95,950	$0
2014	$391,000	$61,000	$178,450	$0

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 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.

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 National Energy Board of Canada (the "**NEB**"). 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 NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

On July 6, 2012, the federal government enacted the *Jobs, Growth and Long-term Prosperity Act* which made amendments to the National Energy Board Act ("**NEB Act**") that affect the NEB's export and import framework. As a result of these changes, the NEB issued the Interim Memorandum of Guidance Concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the National Energy Board Act ("**Interim Oil and Gas MOG**"). The purpose of the Interim Oil and Gas MOG is to provide guidance to applicants until such time as the NEB has completed the review and update of the regulatory framework. As part of the review and update, the NEB is currently proposing amendments to the *National Energy Board Part VI (Oil and Gas) Regulations* and the *National Energy Board Export and Import Reporting Regulations*.

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 NEB 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 NEB 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 an NEB 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 NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Saskatchewan and Alberta also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

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. In the context of energy resources, Canada continues to remain 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 the party maintaining the restriction 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.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Trans-Pacific Partnership

On October 5, 2015, Canada and 11 other countries announced an agreement in respect of the Trans-Pacific Partnership ("**TPP**"). Canada and each participating country must ratify the TPP in their national legislatures. The TPP would lower tariffs on a wide range of Canadian products and benefit exporters across Canada in a number of sectors, including agriculture, wood and wood products, chemicals and plastics, and fish and seafood. An agreement would also bring enhanced and more predictable market access for Canada's services providers.

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. Payments to aboriginal governments are exempt from reporting obligations until 2017. 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.

The Federal Government has signaled it will, inter alia, phase out subsidies for the oil and gas industry, which include allowing the use of the Canadian Exploration Expenses tax deduction only in cases of successful exploration activities, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change within 90 days of the United Nations 2015 Paris Climate Conference, which concluded on December 12, 2015. These changes could affect earnings of companies operating in the oil and natural gas industry.

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.

Royalties are currently paid pursuant to "**The New Royalty Framework**" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "**Alberta Royalty Framework**", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula that is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40 percent. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula, with the maximum royalty payable under the royalty regime set at 36 percent.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral tax. 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 four percent of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques, and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). One such initiative was the New Well Royalty Rate, pursuant to which:

- coalbed methane wells will 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;

- shale gas wells will 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;

- horizontal gas wells will 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

- horizontal oil wells and horizontal non-project oil sands wells will 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 July 24, 2014 the Government of Alberta introduced the Enhanced Oil Recovery Program, to be effective as of January 1, 2014. This program encourages the injection of fluids such as hydrocarbons, carbon dioxide, nitrogen, chemicals and other approved substances for the recovery of additional oil. The Government of Alberta shares in the cost to develop the resource by reducing the amount of the royalty due on crude oil (subject to certain approvals and restrictions).

New Alberta Royalty Regime

On January 29, 2016, the Alberta Government announced that it will adopt the recommendations of the Royalty Review Advisory Panel from the "Alberta at a Crossroads, Royalty Review Advisory Panel Report" (the "**Royalty Report**") to modernize Alberta's royalty framework.

The Royalty Report is extensive and recommends a new modernized royalty framework emulating a "revenue minus costs" approach. Further, the Royalty Report provides a harmonized royalty strategy across all hydrocarbons, aimed at rewarding innovation, efficiency and low-cost producers, while leaving oil sands royalties substantively as-is but with more transparency and financial reporting. The new modernized royalty framework ("**MRF**") requires a "Calibration Period" to finalize specific formulas and set up procedures for implementation. Those key formulaic and final inputs, including specific royalty rates, are scheduled to be released by the Calibration Period Committee on or before March 31, 2016.

The stated goal of the MRF is to create a simpler, more transparent and efficient royalty system that encourages investment, creates jobs, and enhances economic activity in Alberta. The MRF is divided by industry segments: conventional, unconventional, oil sands and value-added upgrading. First, all hydrocarbons (crude oil, liquids and natural gas) will be subject to a harmonized "revenue minus costs" approach with changes only applying to new wells spud in 2017 and thereafter (for wells drilled prior to December 31, 2016, existing royalties will remain in effect for 10 years). Second, Alberta's oil sands royalty framework will remain unchanged, subject only to new measures to increase transparency with respect to a project's allowable capital costs and financial reporting. Third, the Royalty Report recommends consideration of certain value-added partial upgrading investments.

The Province of Alberta will adopt the MRF in respect of crude oil, liquids and natural gas. The MRF will only apply to new wells spud after the implementation date of the framework (2017), provided, however, that a sunset provision will be established to transition exempt wells into the MRF 10 years from the implementation date of the MRF. The MRF will adopt a single royalty structure, with no differentiation between produced substances, under which royalty rates are calculated based on a total review of a blend of all hydrocarbon products, and all metrics are based in dollars.

A proxy "revenue minus costs" structure will be undertaken by the adoption of a Drilling and Completion Cost Allowance formula, based on vertical depth and horizontal length, under which average drilling costs for new wells will be estimated by proxy. A flat royalty of 5% will be instituted on early production revenue up to the point of payout (payout achieved when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance). Upon payout, elevated royalty rates will be paid on subsequent production. The existing production formula will be modified to provide that declining royalties based on production rates will be triggered only during the mature phase of a well's life cycle (i.e. once production drops below a set Maturity Threshold, as determined by a calibration team, royalty rates will be adjusted downward). Finally, an updated proxy cost formula will be implemented annually for the determination of the Drilling and Completion Cost Allowance.

Key attributes of the MRF include:

- A Capital Cost Index to track year-over-year inflationary or deflationary changes, and adjust the Drilling and Completion Cost Allowance annually based on the set Capital Cost Index will be established.
- The Index is to be set to 100 in 2017, and will "float" depending on changes in industry costs. In years following, the derivation and public announcement of the Alberta Capital Cost Index will be made by March 31 for application on April 1 of the same year.
- Carbon levies relating to capital cost expenditures will be captured within the Capital Cost Index, which will, by design, adapt over time.

- Following the annual update, the Capital Cost Index will apply to go-forward wells only (i.e. the Capital Cost will be fixed for each well).

As set out within the Royalty Report, the Government of Alberta intends to implement strategic programs to promote expanded production and programs aimed at enhanced hydrocarbon recovery and high risk experimental wells by March 31, 2016. The Government of Alberta has also indicated that it will extend the end date for the Natural Gas Deep Drilling Program and Emerging Research and Technology Initiative so as to cover wells drilled in 2016 and 2017.

It is not possible to predict what impact the implementation of the MRF and its resulting changes to royalties could have on the Corporation's net earnings, funds from operations, cash flow from operating activities, operating netbacks, and reserve values, which could create uncertainty as to the recoverability of the carrying value of the Corporation's petroleum and natural gas assets.

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 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 "new oil" and "third tier oil" and 12.5 for "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 a reference well production rate of 100 m^3 for old oil, new oil and third tier oil, and 250 m^3 per month for 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 new 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.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3 per month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. 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, 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 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 designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5 percent for oil produced prior to April 2013 and 2.25 percent for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards apply to all existing licensed wells and facilities as of July 1, 2015.

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

The Government of Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17 percent reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31 percent larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

It is expected that any regulations eventually implemented by the Government of Canada will have an impact of the oil and gas industry as a whole, which could result in increased costs for Surge to comply with such legislation. In the meantime, 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 greenhouse gases 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

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach and aims for a 50 percent reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the Specified Gas Emitters Regulation ("**SGER**"), which imposes GHG limits, and the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year ("**Regulated Emitters**") are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. At this point Surge does not own or anticipate owning or operating any facilities which emit more than 100,000 tonnes of GHGs 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 June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years (to be increased to 15% as of January 1, 2016 and 20% as of January 1, 2017).

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (i) producing its products with lower carbon inputs; (ii) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols); (iii) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold; (iv) cogeneration compliance adjustments; and (v) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy on GHG emissions will be phased in, starting in January 2017 at $20 per tonne of GHG emissions, increasing to $30 per tonne in January 2018. An oil sands specific approach was also proposed to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation, in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA has received royal assent but has not yet been proclaimed and so is not yet in force. It remains unclear to what degree a scheme implemented under the MRGGA will affect Surge.

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 has 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.

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. 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.

Federal

Pursuant to the Prosperity Act, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

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 Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* the ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") 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 AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* 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, AESRD 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.

Saskatchewan

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), the act governing the regulation of resource development operations in the province. 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

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**") as part of the Liability Management Rating Assessment Process. The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and upon the submission of a license transfer application, and failure to post the required security deposit may result in the initiation of enforcement actions by the AER.

On May 1, 2013, the AER began to implement a three year program of changes to the LLR Program. Some of the important changes which were implemented through this three year process include:

- a 25 percent increase to the prescribed average reclamation cost for each individual well or facility (which increased a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which increased a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which affected the calculation of a licensee's deemed assets, as the reduction from five to three years resulted in the average being more sensitive to price changes); and

- a change to the present value and salvage factor, which increased to 1.0 for all active facilities from 0.75 for active wells and 0.50 for active facilities (which increased a licensee's deemed liabilities).

The changes were implemented over a three-year period, ending August 2015. The first phase was implemented in May 2013, the second phase was implemented in May 2014 and the final phase was implemented in August 2015. The changes to the AB LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On July 4, 2014, the AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment.

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 fund (the "**Oil and Gas Orphan Fund**"). The Oil and Gas Orphan 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.

RISK FACTORS

An investment in Common Shares would be subject to certain risks. Investors should carefully consider the following risk factors:

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 OPEC's ability to adjust supply to world demand, government regulation, political stability 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. 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 Facility, 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.

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.

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

Notwithstanding anything contained in this Annual Information Form, the payment and the amount of dividends declared, if any, will be subject to the discretion of the Board and will depend on the Board's assessment of the Corporation's outlook for growth, capital expenditure requirements, funds from operations, potential opportunities, debt position and other conditions that the Board may consider relevant at such future time, including applicable restrictions that may be imposed under the Credit Facility and on the ability of the Corporation to pay dividends. The amount of future cash dividends, if any, may also vary depending on a variety of factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates. In addition, the market value of the Common Shares may decline if the Corporation's cash dividends decline in the future, and that market value decline may be material. 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. Alberta is currently reviewing its royalty framework and is scheduled to announce the new royalty regime in January 2016 and such regime changes are expected to come into effect in 2017. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

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. Surge's management may initiate certain hedges to mitigate these risks. 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.

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

Surge will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding abandonment and reclamation in respect of its properties, which abandonment and reclamation costs may be substantial. A breach of such legislation or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made.

Credit Facility Risks

The Corporation currently has the Credit Facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under the Credit Facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facility, 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 Facility, the lenders under the Credit Facility 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 Facility may impose operating and financial restrictions on the Corporation that could include restrictions on the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

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

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 company. Moreover, future activities may require Surge to alter its capitalization significantly. The inability of the company 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 Reserve Reports 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 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

The Corporation has recently completed a number of acquisitions and may complete future acquisitions 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.

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.

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.

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.

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

The Common Shares 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 ceasing to be listed for trading on the TSX, which would have a material adverse effect on the value of the Common Shares. There can be no assurance that the Common Shares 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, environmental 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*".

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, 2015, 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

Each of James Pasieka, a director of the Corporation, and Michael Bennett, the Corporate Secretary of the Corporation, is a partner of the national law firm McCarthy Tétrault LLP, which law firm rendered 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

The auditor of the Corporation is KPMG LLP who has been the auditor since May 5, 2010.

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

INTEREST OF EXPERTS

The Reserves Report and certain reserves estimates contained in filings made by the Corporation under National Instrument 51-102 – Continuous Disclosure Requirements during the year ended December 31, 2015 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% 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 2015. Additional financial information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2015.

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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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, 2015, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	December 31, 2015	Canada				
Total			**Nil**	**1,137,603**	**Nil**	**1,137,603**

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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, 2015)".

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
February 3, 2016

Original Signed by Matthew J. Tymchuk, P.Eng.

Matthew J. Tymchuk, P.Eng.
Supervisor, Engineering and Partner

Original Signed by Alec Kovaltchouk, P.Geo.

Alec Kovaltchouk, P.Geo.
Vice-President, Geoscience and Partner

Original Signed by Attila A. Szabo, P.Eng.

Attila A. Szabo, P.Eng.
Vice-President, Strategic Advisory and Director

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**") is 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, 2015, 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, 2015 (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 are the reports of the independent qualified reserves evaluators of on the reserves data; and

(c) the content and filing of this report.

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

(signed) "Paul Colborne"	*(signed) "Paul Ferguson"*
Paul Colborne, President & Chief Executive Officer and Chairman of the Board of Directors	Paul Ferguson, Vice-President, Finance and Chief Financial Officer
(signed) "Colin Davies"	*(signed) "P. Daniel O'Neil"*
Colin Davies, Director & Chairman of the Reserves Committee	P. Daniel O'Neil, Director

March 16, 2016

SCHEDULE "C"

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 quarterly 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; and

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

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 form time to time.

10. The Audit Committee shall review the risk management policies 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 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 regarding questionable accounting or auditing matters.

12. 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.

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

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

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