STORM RESOURCES LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

MARCH 29, 2018

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DEFINITIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this AIF. 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* (Alberta);

"**AIF**" means this annual information form;

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

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

"**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 Share**" or "**Common Shares**" means, respectively, one or more common shares in the capital of Storm;

"**Corporation**" or "**Storm**" means Storm Resources Ltd.;

"**Credit Facility**" means the $165,000,000 extendible revolving bank facility of the Corporation, as amended from time to time, based on the Corporation's producing reserves;

"**HRB**" means the Horn River Basin in northeast British Columbia;

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

"**InSite**" means InSite Petroleum Consultants Ltd.;

"**InSite Report**" means the report prepared by and containing the evaluation of InSite of the oil, NGL and natural gas reserves attributable to the properties of the Corporation, in accordance with NI 51-101, dated February 23, 2018 and effective December 31, 2017;

"**June 2015 Financing**" means the $36,400,000 bought deal short form prospectus financing of Common Shares which was completed on June 10, 2015;

"**NEB**" means the National Energy Board;

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

"**SEO**" means Storm Exploration Inc.;

"**SGR**" means Storm Gas Resource Corp.;

"**Spectra**" means Spectra Energy;

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

"**TSXV**" means the TSX Venture Exchange; and

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

The information set out in this AIF is stated as at December 31, 2017 unless otherwise indicated.

SELECTED ABBREVIATIONS

In this AIF, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	barrel	Bcf	billions of cubic feet
Bbls	barrels of oil or natural gas liquids	GJ	gigajoule
Bbls/d	barrels per day	Mcf	thousands of cubic feet
Mbbls	thousands of barrels	Mmcf	millions of cubic feet
Mboe	thousands of barrels of oil equivalent	Mcf/d	thousands of cubic feet per day
NGL	natural gas liquids	Mmbtu	millions of British Thermal Units

AECO-C	leading Canadian benchmark price for natural gas
AER	Alberta Energy Regulator
API	American Petroleum Institute
° API	is an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specific gravity of 28º API or higher is generally referred to as light crude oil
Boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 Boe for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
Boe/d	barrel of oil equivalent per day
CCS	carbon capture and storage
GHG	greenhouse gas
OPEC	Organization of Petroleum Exporting Countries
$U.S.	United States dollar
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

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	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	Mmbtu	0.949
Mmbtu	Gigajoules	1.055

CURRENCY

In this AIF, references to “dollars” and “$” are to the currency of Canada, unless otherwise indicated.

NON-GAAP MEASURES

Within this AIF, terms may be used which are not recognized under Generally Accepted Accounting Principles ("GAAP"). Specifically, "netbacks", "field operating netbacks", "field operating netback including hedging", "cash", measurements "per commodity unit" and "per Boe" do not have any standardized meaning as prescribed by GAAP and are regarded as non-GAAP measures. These non-GAAP measures may not be comparable to the calculation of similar amounts for other entities and readers are cautioned that use of such measures to compare enterprises may not be valid. Non-GAAP terms are used to benchmark operations against prior periods and peer group companies and are widely used by investors, lenders, analysts and other parties. Field operating netbacks and field operating netbacks including hedging are common non-GAAP measurements applied in the oil and gas industry and are used by management to assess operational performance of assets. Field operating netbacks are calculated by deducting royalties, production and transportation expenses from revenue from product sales and are presented on a per-Boe basis.

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

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

The recovery and reserve estimates of oil, 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 Boe. Boe 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.

Reserves Categories

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

(b) "**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.

(c) "**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.

(d) "**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.

(e) "**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 and probable) 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.

(f) "**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.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve 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 are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

- For proved plus probable reserves, at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimation.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Drilling Locations

This AIF discloses drilling inventory in two categories: (i) proved locations; and (ii) probable locations. Proved locations and probable locations are derived from InSite's reserves evaluation effective December 31, 2017 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Of the 78.6 drilling locations identified herein, 66 net are proved locations and 12.6 net are probable locations. The drilling locations on which the Corporation actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, commodity prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Additional Definitions

The following terms, used in the preparation of the InSite Report in accordance with NI 51-101 and this AIF, have the following meanings:

(a) "**abandonment and reclamation costs**" means all costs associated with the process of restoring a reporting issuer's property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities;

(b) "**crude oil**" or "**oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or NGL.

(c) "**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features;

(d) "**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and 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;

(iii) service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(iv) 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

(v) provide improved recovery systems.

(e) "**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.

(f) "**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 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 yearly lease rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(iii) costs of dry holes;

(iv) costs of drilling and equipping exploratory wells; and

(v) costs of drilling exploratory type stratigraphic test wells.

(g) "**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

(h) "**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

(i) "**future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(i) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(ii) without deducting estimated future costs that are not deductible in computing taxable income;

(iii) taking into account estimated tax credits and allowances; and

(iv) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

(j) "**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs.

(k) "**gross**" means:

(i) in relation to the Corporation'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 Corporation;

(ii) in relation to wells, the total number of wells in which the Corporation has an interest; and

(iii) in relation to properties, the total area of properties in which the Corporation has an interest.

(l) "**light crude oil**" means crude oil with a relative density greater than 31.1 degrees API gravity;

(m) "**medium crude oil**" means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity;

(n) "**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases.

(o) "**NGL**" or "**natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes and condensates.

(p) "**net**" means:

(i) in relation to the Corporation'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 the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(iii) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

(q) "**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

(r) "**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract NGL) and field storage of oil and natural gas from wellbores.

(s) "**property**" includes:

(i) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest; and

(ii) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others.

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

(t) "**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(i) costs of lease bonuses and options to purchase or lease a property;

(ii) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

(iii) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

(u) "**proved property**" means a property or part of a property to which reserves have been specifically attributed.

(v) "**reservoir**" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(w) "**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.

(x) “**solution gas**” means natural gas dissolved in crude oil.

(y) “**stratigraphic test well**” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) ”exploratory type” if not drilled into a proved property; or (ii) ”development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “**evaluation wells**”.

(z) “**support equipment and facilities**” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

(aa) “**unproved property**” means a property or part of a property to which no reserves have been specifically attributed.

(bb) “**well abandonment costs**” means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

FORWARD-LOOKING STATEMENTS

Certain information set forth in this AIF, including management’s assessment of Storm’s future plans and operations specifically in relation to 2018 and 2019, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as “anticipate”, “believe”, “intend”, “plan”, “expect”, “estimate”, “budget”, “forecast”, “would”, “could”, “will”, “may”, “future” or other similar words and include statements relating to or associated with individual wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Corporation’s operations or financial position. Any statements regarding the following are forward-looking statements:

- the performance characteristics of the Corporation’s natural gas and NGL properties;
- future market prices and costs of and supply and demand for crude oil, NGL and natural gas prices;
- future gains or losses from commodity price contracts;
- future production volumes in 2018 and 2019, production volumes by commodity and production declines;
- the size of the natural gas and NGL reserves of the Corporation and anticipated future funds flow from such reserves;
- future revenues and costs (including royalties) and revenues and costs per commodity unit;
- future capital expenditures and their allocation to specific exploration and development activities or periods, particularly with respect to the number of wells to be drilled as part of the 2018 capital program;
- future drilling, completion and tie-in of wells;
- future facility access, acquisition or construction and entry in service and timing thereof;
- future pipeline capacity;
- future funds flow including per-share amounts;
- future earnings or losses including per-share amounts;
- future IFRS and non-IFRS measurements;
- future sources of funding for capital programs and future availability of such sources;
- future asset acquisitions or dispositions;
- intentions with respect to investments;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future abandonment and reclamation costs;

- development plans for Storm's Umbach and HRB properties;
- future debt levels including working capital deficiency;
- future availability and terms of financing, including credit facilities;
- future tax liabilities and future use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources and timing of such recoverability;
- estimates of ultimate recovery from wells;
- future finding and development costs, production costs, transportation costs, interest and financing costs, and general and administrative costs, in total and by commodity unit;
- treatment under governmental regulatory regimes and tax and royalty laws;
- estimates of the future life of depreciable assets;
- future charges for depletion, depreciation and accretion;
- future interest rates;
- estimates on a per-share basis and per-Boe basis;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations including agreements pertaining to processing, transportation and marketing of natural gas, condensate and NGL;
- future availability and cost of drilling rigs, completion and tie-in services and other oilfield services;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed, including twinning of the third field compression facility; and
- changes to any of the foregoing.

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

- natural gas and NGL production levels;
- the success of the Corporation's operations and exploration and development activities;
- prevailing climatic conditions, commodity prices, interest and exchange rates;
- 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 enhanced recovery 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;
- the success of exploration and development activities; and
- access to market for the Corporation's production.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include:

- industry conditions, including commodity prices;
- pipeline and third party facility capacity constraints and access to sales markets;
- volatility of commodity prices;
- currency fluctuations;
- imprecision of reserve estimates and related costs including royalties, production costs and future development costs;
- environmental risks;
- stock market volatility;
- ability to access sufficient capital from internal and external sources and the ability of the Corporation to realize value from acquired assets and corporations;
- credit facility risks;

- failure to realize anticipated benefits of acquisitions and dispositions;
- physical and operational risks inherent in oil and natural gas field activity;
- 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;
- success of drilling programs;
- geological, technical, drilling, completion and processing problems;
- results of enhanced recovery responses;
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry;
- unplanned outages at third party natural gas processing facilities and pipelines; and
- the other factors discussed under "*Risk Factors*".

All of these caveats should be considered in the context of current economic conditions, in particular volatility in commodity prices, enduring sub-economic prices for crude oil and natural gas, the attitude of lenders and investors towards natural gas assets, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of Storm.

Ultimate recovery of reserves is based on forecasts of future results, estimates of amounts not yet determinable and assumptions by management of Storm.

Statements relating to "reserves" or "resources" are forward-looking statements, including financial measurements such as net present value, as they involve the assessment, based on estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Storm disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law.

References to forward-looking information are made elsewhere in this AIF. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

THE CORPORATION

Storm Resources Ltd. was incorporated under the ABCA on June 8, 2010 under the name of "1541229 Alberta Ltd.". On July 30, 2010, the Corporation filed articles of amendment to change its name to "Storm Resources Ltd.". On March 23, 2012, the Corporation filed articles of amalgamation following a corporate acquisition.

Storm is a reporting issuer (or the equivalent thereof) in each of the provinces of Canada. On August 31, 2010, the Common Shares were listed and posted for trading on the TSXV. On September 27, 2017, the Common Shares were listed and posted for trading on the TSX under the existing symbol "SRX" and were concurrently delisted from the TSXV.

As of March 29, 2018, the Corporation has one subsidiary, SGR, which is wholly-owned and was incorporated under the ABCA.

The Corporation's registered office is located at 4000, 421 - 7th Avenue S.W., Calgary, Alberta, T2P 4K9, and its head and principal office is located at 200, 640 – 5th Avenue S.W., Calgary, Alberta, T2P 3G4.

GENERAL DEVELOPMENT OF THE BUSINESS

Year-Ended 2015

On June 10, 2015, Storm completed the June 2015 Financing, which was a bought deal financing by way of short form prospectus pursuant to which Storm, through a syndicate of underwriters, issued an aggregate of 8,000,000 Common Shares at a price of $4.55 per Common Share for aggregate gross proceeds of $36.4 million.

On July 15, 2015, Storm completed the disposition of properties in the Grande Prairie area of northwest Alberta, with production prior to sale of approximately 500 Boe/d, for proceeds of $24.0 million (the "**2015 Grande Prairie Disposition**"). The net proceeds of the 2015 Grande Prairie Disposition were applied to reduce Storm's bank debt. The effective date of the 2015 Grande Prairie Disposition was July 1, 2015. Following the 2015 Grande Prairie Disposition, the remaining Alberta assets of Storm consist of one property in the Valhalla area. The disposition resulted in the sale of all of Storm's reserves of crude oil.

In December 2015, Storm began to diversify natural gas sales away from BC Station 2 with the start of firm service on the Alliance Pipeline to Chicago. Contracted capacity increased from 43 Mmcf per day in 2016 to 55 Mmcf per day in 2018.

In 2015, Storm drilled 10 horizontal wells (10.0 net) in the Montney formation at Umbach with a 100% success rate and 13 horizontal wells (13.0 net) were completed. At year end there was an inventory of six drilled wells which included two completed wells. The second field compression facility was expanded to 62 Mmcf per day and a condensate stabilizer, a fuel gas conditioning unit and equipment for salt water disposal were also added, for an investment totaling $23.5 million.

Year-Ended 2016

During 2016, construction of a third field compression facility at Umbach began, with the facility completed in January 2017, expanding Storm's compression capacity to 115 Mmcf per day. The total cost of construction was approximately $25 million with $24 million incurred to the end of 2016 and the remaining $1 million incurred in January 2017. The new facility will be twinned in due course at an incremental cost of approximately $7 million bringing compression capacity to 150 Mmcf per day. The third compression facility began operating in January 2017.

In September 2016, Storm entered into a natural gas processing arrangement at Umbach with Spectra (subsequently acquired by Enbridge Inc.) that had an effective date of January 1, 2017 and a total commitment of 65 Mmcf per day of raw gas at terms ranging from 5 to 15 years. The arrangement reduced operating costs by approximately 15% and supports future growth. The arrangement includes an option to increase contracted capacity while providing for continued diversification of natural gas sales with access to three sales pipelines through the McMahon Gas Plant (Alliance Pipeline to Chicago, TransCanada NGTL system to AECO, Spectra T-North mainline to Westcoast Station 2).

In 2016, Storm drilled 12 wells (12.0 net) in the Montney formation at Umbach and completed 10 wells (10.0 net). Nine wells were brought on production, resulting in an inventory of nine drilled wells with six awaiting completion at the end of 2016.

Year-Ended 2017

On January 1, 2017, Storm's natural gas processing arrangement with Spectra (Enbridge) came into effect, directing approximately 80% of Storm's raw natural gas to the McMahon Gas Plant with the remaining amount processed at the Stoddart Gas Plant. In January 2017, a third field compression facility commenced operation at Umbach which increased compression capacity to 115 Mmcf per day of raw gas leading to a step change in natural gas production levels. Capacity can be increased to 150 Mmcf per day by installing additional compression. The increased compression capacity would support growth in corporate production to approximately 27,000 Boe per day.

On May 16, 2017, the Corporation appointed Michael J. Hearn as Chief Financial Officer and Emily Wignes as Vice President, Finance.

In the second quarter of 2017, the Corporation's Credit Facility was increased to $165 million from $130 million with $101 million drawn at year end.

On September 27, 2017, the Corporation's Common Shares commenced trading on the TSX under the symbol "SRX".

In 2017, Storm drilled 16 wells (100% working interest) in the Montney formation at Umbach and completed 12 wells. Thirteen wells were brought on production (13.0 net), leaving an inventory of 12 wells (12.0 net) that had not started production at year end, two of which are completed wells.

The InSite Report assigned gross proved plus probable reserves as at December 31, 2017 in the amount of 128,963 Mboe, a year-over-year increase of 24%. Storm's undeveloped lands totaled 245,344 net acres at the end of 2017. See "*Statement of Reserves Data and Other Oil and Gas Information*".

DESCRIPTION OF THE BUSINESS

General

Storm is engaged in the exploration for, and the acquisition, development and production of natural gas and NGL reserves in the provinces of Alberta and British Columbia. The Corporation focuses on a selective combination of exploratory and development drilling, along with strategic asset and corporate acquisitions where the Corporation believes further exploration and exploitation opportunities exist. Storm's main areas of activity are located in the Umbach and HRB areas of northeast British Columbia, with minor interests in the Valhalla area of north central Alberta.

Storm's business objective involves the identification and exploitation of opportunities to develop crude oil and natural gas assets profitably in Western Canada. The Corporation uses a number of strategies to manage the operational and financial risks associated with this objective including a strong geographical and geological focus to its operations, discipline with capital investment, maintaining a low cost structure, ownership of its facilities and operatorship of its assets wherever possible.

Although the Corporation favours a 100% working interest in its properties, it will accept a lower working interest in circumstances where capital requirements exceed either the Corporation's funding capacity or its tolerance for risk.

The Corporation looks to acquire assets in areas with which it is familiar, provided that the acquired assets come at a price competitive with the Corporation's internal finding and development costs and/or are strategic to the Corporation's continued growth and expansion.

Management of the Corporation combines a growth oriented operating philosophy with a disciplined approach to capital investment, based on funding the Corporation's capital investment out of funds flow, debt (within an acceptable multiple of funds flow), selective asset dispositions and, in appropriate circumstances, the issuance of equity. In certain circumstances, the Corporation will temporarily exceed internal debt to funds flow targets to complete an acquisition, or a seasonally oriented drilling program or a major addition to facilities. Hedging may be used as part of a debt management program to stabilize funds flow through the use of instruments such as fixed price sales of commodities, pricing collars, interest rate swaps, fixing of foreign currency exchange rates, fixing of index differentials and similar. Entering into hedging arrangements is subject to compliance with the Corporation's hedging policy which requires the approval of the Board of Directors.

The Corporation focuses on management of costs, both capital and operating. A low cost structure means that the Corporation can continue to execute its business plan and grow in periods of low commodity prices, particularly for natural gas in the last several years, and thus protect its competitive position.

Competitive Conditions

The Corporation actively competes for reserve acquisitions, exploration leases, licences and concessions, equipment and skilled industry personnel with a large number of other oil and gas companies, many of which have significantly greater financial resources than the Corporation. The Corporation's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies of varying sizes.

The Corporation's ability to continue to bid on and acquire additional property rights, to discover and produce reserves, to participate in drilling opportunities, to construct and operate production facilities and to identify and enter into advantageous commercial arrangements is dependent upon (i) the Corporation developing and maintaining close working relationships with its industry partners; (ii) its ability to select and evaluate suitable properties for acquisition and development; (iii) its ability to consummate commercially attractive transactions in a competitive environment; and (iv) the maintenance of adequate financial capacity.

Cyclical Nature of Business

Apart from seasonal load restrictions on roads, Storm's key properties allow for drilling and other wellsite activities to continue throughout the year.

Approximately 60% of Storm's revenue in 2017 was generated from the sale of natural gas, with 40% coming from the sale of condensate and NGL. North American natural gas pricing is dependent on a wide range of factors, such as drilling activity, storage levels, supply increases from newly developed reserves, as well as demand, which is weather sensitive and peaks during the cold winter months. This can result in significant price volatility. In particular, since 2009, natural gas markets in North America have seen deliveries of increasing volumes of natural gas from shale deposits in the United States, exploitation of which in recent years has been facilitated by improvements in drilling and fracturing technologies. Production of natural gas from shale is characterized by very high initial rates, followed by rapid declines with the consequence being increasing volatility and decreasing prices for natural gas in recent years.

Oil and NGL prices have also fluctuated greatly during recent years and are determined by global supply and demand factors, including weather and general economic conditions, competition from other oil and natural gas producing regions, pipeline access and geopolitical circumstances. The latter circumstance emerged late in 2014 which resulted in reduced prices for crude oil and for condensate which is priced with reference to crude oil. A more balanced outlook began to materialize in 2017 leading to an improvement in crude oil and condensate prices since 2016.

Since 2013, the Corporation has primarily focused on exploiting a high condensate and NGL content natural gas property in the Umbach area of northeast British Columbia.

Specialized Skill and Knowledge

Exploration for and the acquisition, development of and production of oil, natural gas and NGL reserves requires specialized skills and knowledge in the areas of petroleum engineering, geophysics, geology, facility construction and land title. The Corporation has personnel with the required specialized skills and knowledge. While the labour market in the industry is periodically highly competitive, the Corporation expects to be able to attract and retain appropriately qualified employees throughout 2018.

Renegotiation or Termination of Contracts

To the knowledge of management, the Corporation is not a party to any material contract that may be subject to renegotiation or termination in 2018.

Employees

As of December 31, 2017, the Corporation had 25 full-time employees, 6 part-time employees and 2 consultants.

MANAGEMENT OF THE CORPORATION

As at the date hereof, the name, municipality of residence and principal occupation of the directors and senior officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held	Date First Elected or Appointed as Director[5]
Brian Lavergne Calgary, Alberta	President, Chief Executive Officer and Director	June 8, 2010
Michael J. Hearn Calgary, Alberta	Chief Financial Officer and Corporate Secretary	-
Robert S. Tiberio Calgary, Alberta	Chief Operating Officer	-
Jamie P. Conboy Calgary, Alberta	Vice President, Geology	-
Emily Wignes Calgary, Alberta	Vice President, Finance	-
H. Darren Evans Calgary, Alberta	Vice President, Exploitation	-
Bret A. Kimpton Calgary, Alberta	Vice President, Production	-
Matthew J. Brister[2][3] Calgary, Alberta	Director	June 8, 2010
John A. Brussa Calgary, Alberta	Director	June 8, 2010
Mark A. Butler[1][2][4] Calgary, Alberta	Director	June 8, 2010
Stuart G. Clark[1] Calgary, Alberta	Chairman and Director	June 8, 2010
Gregory G. Turnbull, QC[3] Calgary, Alberta	Director	June 8, 2010
P. Grant Wierzba[2][3] Calgary, Alberta	Director	June 8, 2010
James K. Wilson[1][4] Calgary, Alberta	Director	June 8, 2010

Notes:

(1) Member of the Audit Committee.
(2) Member of the Compensation, Governance and Nomination Committee.
(3) Member of the Reserves Committee.
(4) Holds ICD.D director certification from the Institute of Corporate Directors.
(5) The directors will hold office until the next annual meeting of holders of Common Shares or until their successor is duly elected or appointed, unless their office is earlier vacated in accordance with the By-laws.

As at the date hereof, the officers and directors, as a group, held, directly or indirectly, or exercise control or direction over 14,762,768 Common Shares representing approximately 12.1% of the issued and outstanding Common Shares.

Each of Lavergne, Hearn, Tiberio, Conboy, Wignes, Evans and Kimpton, devotes his or her full time and attention to the business and affairs of Storm. The remaining directors of Storm devote their time and attention to the affairs of Storm only as required. Profiles of Storm's directors and officers and the particulars of their respective principal occupations during the previous five years as of March 29, 2018 are set forth below.

Brian Lavergne, President, Chief Executive Officer and Director

Mr. Lavergne has been the President and Chief Executive Officer and a director of Storm since June 8, 2010. Mr. Lavergne holds a Bachelor of Science in Mechanical Engineering from the University of Alberta.

Michael J. Hearn, Chief Financial Officer and Corporate Secretary

Mr. Hearn was appointed as Chief Financial Officer of Storm on May 16, 2017 and Corporate Secretary of Storm on August 15, 2017. Mr. Hearn is a Chartered Accountant with 14 years of experience who initially joined Storm on November 1, 2016 as Controller. Prior thereto, Mr. Hearn worked for six years with an independent energy investment bank as an equity research analyst.

Robert S. Tiberio, Chief Operating Officer

Mr. Tiberio has been the Chief Operating Officer of Storm since August 18, 2010.

Jamie P. Conboy, Vice President, Geology

Mr. Conboy was appointed Vice President, Geology of Storm on May 1, 2015. Prior thereto, he held the position of Chief Geologist at Storm since August 17, 2010.

Emily Wignes, Vice President, Finance

Ms. Wignes was appointed Vice President, Finance of Storm on May 16, 2017. Ms. Wignes is a Chartered Accountant and initially joined Storm on December 1, 2016 as Manager, Accounting after two years as Manager, Financial Reporting for an intermediate producer. Prior thereto, Ms. Wignes was employed in senior accounting positions at other intermediate and large producers.

H. Darren Evans, Vice President, Exploitation

Mr. Evans was appointed Vice President, Exploitation on May 1, 2015. Prior thereto, he held the position of Engineering Manager at Storm since August 17, 2010.

Bret A. Kimpton, Vice President, Production

Mr. Kimpton was appointed Vice President, Production on May 1, 2015. Prior thereto, he held senior engineering positions within the organization progressing from Senior Production Engineer to Production Manager.

Matthew J. Brister, Director

Mr. Brister is a retired businessman and was Chairman of the Board of Chinook Energy Inc. ("Chinook") from December 2013 until June 2017. Prior thereto, Mr. Brister was Chief Executive Officer and a director of Chinook from June 2009 until December 2013. Mr. Brister holds a Bachelor of Science in Geology from the University of Calgary.

John A. Brussa, Director

Mr. Brussa is Chairman at Burnet, Duckworth & Palmer LLP, a law firm specializing in the energy sector. He sits on the board of a number of public and private corporations in the energy, energy services, financial and marketing sectors.

Mark A. Butler, Director

Mr. Butler is an independent businessman and was previously the CEO of WestPac LNG Corporation, an early stage private capital entrant into the development of LNG facilities in British Columbia. Mr. Butler holds a Bachelor of Laws degree from the University of Saskatchewan, a Masters of Business Administration from the University of Calgary, and ICD.D director certification from the Institute of Corporate Directors.

Stuart G. Clark, Chairman and Director

Mr. Clark is a retired businessman and served as a director and Chairman of Rock Energy Inc. from January 2004 to July 2016 and a director of Chinook from June 2009 until May 2017. Mr. Clark holds a Bachelor of Commerce (Honours) from the University of Manitoba.

Gregory G. Turnbull, QC, Director

Mr. Turnbull is a senior partner at McCarthy Tétrault LLP, which he joined in July, 2002. Mr. Turnbull is currently a director of a number of public and private corporations, largely associated with the energy industry.

P. Grant Wierzba, Director

Mr. Wierzba is a director of Chinook and, in addition, was Vice President, Operations of Chinook until December 2013. Mr. Wierzba holds a Bachelor of Science in Engineering from the University of Alberta.

James K. Wilson, Director

Mr. Wilson has been managing director of Walwil Resources Ltd., an oil and gas financial consulting company, since July 2017 and from February 2013 until September 2015. He was the Chief Financial Officer and Corporate Secretary of Aspenleaf Energy Limited from September 2015 until June 2017. From June to November of 2015 Mr. Wilson was a director of Marquee Energy Ltd. From October 2011 to February 2013, Mr. Wilson was Chief Financial Officer of Mako Hydrocarbons Ltd. and was a director of Rock Energy Inc. from October 2004 to June 2013. Mr. Wilson maintains memberships in the Institute of Corporate Directors, Financial Executives International of Canada and the Chartered Professional Accountants of Alberta. Mr. Wilson holds a Bachelor of Commerce degree from the University of Calgary, a Chartered Accountant designation and ICD.D director certification from the Institute of Corporate Directors.

Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as set forth below:

(a) no director or executive officer is, or within the ten years prior to the date hereof has been, a director, chief executive officer or chief financial officer of any other issuer that, while that person was acting in that capacity:

 (i) was the subject of a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or

 (ii) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemptions under securities legislation that was issued after the director or officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

(b) no director, 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, or within the ten years prior to the date hereof has been, a director or executive officer 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 preceding the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual; and

(c) no director, executive officer or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, within the last 10 years, 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. Gregory G. Turnbull, a director of the Corporation, was a director of Action Energy Inc., a corporation engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed into receivership on October 28, 2009 by its major creditor and Mr. Turnbull resigned as a director immediately thereafter. In addition, Mr. Turnbull was a director of Sonde Resources Corp. ("**Sonde**"), a Canada-based diversified global energy company, which filed for bankruptcy on February 2, 2015. Mr. Turnbull resigned as a director of Sonde on March 27, 2014. Mr. Turnbull resigned as a director of Porto Energy Corp. ("**Porto**") on May 30, 2014 following the decision by Porto's directors and management to wind down Porto's operations due to capital constraints. Porto has subsequently become subject to cease trade orders for failure to file periodic disclosure (interim financial filings) and such cease trade orders remain in effect.

Mr. John A. Brussa, a director of the Corporation, resigned as a director of Calmena Energy Services Inc. ("**Calmena**") on June 30, 2014. On January 19, 2015, a senior lender of Calmena (the "**Senior Lender**") made an application to the Court of Queen's Bench of Alberta (the "**Court**") to appoint an interim receiver under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Calmena was suspended by the TSX. On January 20, 2015, the Senior Lender was granted a receivership order by the Court.

Mr. Brussa was also a director of Enseco Energy Services Corp. ("**Enseco**"), a public oilfield service company, which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Mr. Brussa resigned as a director of Enseco on October 14, 2015. On December 21, 2015, Enseco was assigned into bankruptcy by the receiver.

Mr. Brussa was a director of Argent Energy Ltd. which was the administrator of Argent Energy Trust. On February 17, 2016, Argent Energy Trust and its Canadian and United States holding companies (collectively, "**Argent**") commenced proceedings under the *Companies' Creditors Arrangement Act* ("**CCAA**") for a stay of proceedings until March 19, 2016. On the same date, Argent filed voluntary petitions for relief under Chapter 15 of the *United States Bankruptcy Code* ("**Chapter 15**"). On March 9, 2016, the stay of proceedings under the CCAA was extended until May 17, 2016. Additionally, on

March 10, 2016, the U.S. Bankruptcy Court approved an order recognizing the CCAA as the foreign main proceedings under Chapter 15. Mr. Brussa resigned as a director of Argent Energy Ltd. on June 30, 2016.

Mr. Brussa resigned as a director of Twin Butte Energy Ltd. ("**Twin Butte**") on September 1, 2016. On September 1, 2016, the senior lenders of Twin Butte (the "**Senior Lenders**") made an application to the Court to appoint a receiver and manager over the assets, undertakings and property of Twin Butte under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Twin Butte was suspended by the Toronto Stock Exchange. On September 1, 2016, the Senior Lenders were granted a receivership order by the Court.

Mr. Brussa was a director of Virginia Hills Oil Corp. ("**VHO**"), a TSXV listed oil and gas company. On February 13, 2017, VHO received a demand notice and notice of intention to enforce security from its lenders and agreed to consent to the early enforcement of the lenders' security and the appointment of a receiver over all of the current and future assets, undertakings and properties of VHO. The receiver was appointed on February 13, 2017. Mr. Brussa resigned as a director of VHO on February 24, 2017.

Conflicts of Interest

Circumstances may arise where members of the Board of Directors are directors or officers of corporations which are in competition to the interests of Storm. No assurances can be given that opportunities identified by such Board members in the context of their relationship with another corporation will be provided to Storm. Pursuant to the ABCA, directors who have an interest in a proposed transaction upon which the Board of Directors is voting are required to disclose their interests and refrain from voting on the transaction.

Mr. John A. Brussa, a director of the Corporation, is Chairman and a partner of Burnet, Duckworth & Palmer LLP, a law firm that provides legal services to Storm. The Board of Directors does not believe that any of the activities undertaken by Mr. Brussa or by Burnet, Duckworth & Palmer LLP interfere, or could be perceived to interfere, in any material way with his ability to act with a view to the best interests of Storm.

Mr. Gregory G. Turnbull, a director of the Corporation, is a partner of McCarthy Tétrault LLP, a law firm that provides legal services to Storm. The Board of Directors does not believe that any of the activities undertaken by Mr. Turnbull or by McCarthy Tétrault LLP interfere, or could be perceived to interfere, in any material way, with his ability to act with a view to the best interests of Storm.

Legal Proceedings and Regulatory Actions

There are no outstanding legal proceedings material to the Corporation to which the Corporation is a party, or was party to in 2017, or in respect of which any of its properties are subject, or was the subject matter of in 2017, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2017, 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

There are no material interests, direct or indirect, of a director or executive officer of the Corporation, a shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares, or an associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial that has materially affected or would materially affect the Corporation.

AUDIT COMMITTEE INFORMATION

Storm's Audit Committee is responsible for reviewing and approving the financial statements and public reports of the Corporation, considering the existence and adequacy of internal and management controls and reviewing and approving material accounting policies and measurements. The Audit Committee is also responsible for reviewing the annual audit and quarterly reviews and communicating directly with the external auditor as to their findings.

Audit Committee Charter

The full text of the Audit Committee's Charter is included in Appendix C of this AIF.

Composition of the Audit Committee

The Audit Committee is composed of three directors, James K. Wilson (Chairman), Mark A. Butler and Stuart G. Clark, each of whom are independent and financially literate, as such terms are defined in National Instrument 52-110 – *Audit Committees* ("**NI 52-110**"). Collectively, the Audit Committee has the education and experience to fulfill the responsibilities outlined in the Audit Committee's Charter. The relevant education and experience of each Audit Committee member is outlined below:

Mr. Wilson was a director of the Corporation's predecessor company, Storm Exploration Inc., and has been a director and officer of a number of public oil and gas companies. Mr. Wilson holds a Bachelor of Commerce degree from the University of Calgary, a Chartered Accountant designation and ICD.D director certification from the Institute of Corporate Directors.

Mr. Butler was a director of the Corporation's predecessor company, Storm Exploration Inc., and was in the past CEO of WestPac LNG Corporation. Mr. Butler holds a Bachelor of Laws degree from the University of Saskatchewan, a Masters of Business Administration from the University of Calgary, and ICD.D director certification from the Institute of Corporate Directors.

Mr. Clark has been a director and chairman of a number of public oil and gas companies and has experience acting as an audit committee member.

Each member of the Audit Committee has: (i) an understanding of the accounting principles used by the Corporation to prepare its financial statements; (ii) the ability to assess the general application of those principles in connection with the estimates, accruals and reserves; (iii) experience in preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising individuals engaged in such activities; and (iv) an understanding of internal controls and procedures for financial reporting.

Pre-Approval of Policies and Procedures

The Audit Committee is authorized by the Board of Directors to review the performance of the Corporation's external auditors, and approve in advance the provision of services other than audit services and to consider the independence of the external auditors, including reviewing the range of services provided in the context of all consulting services bought by the Corporation. The Audit Committee is authorized to approve any non-audit services or additional work, which the Chairman of the Audit Committee deems as necessary.

External Auditor Service Fees

Audit Fees

Ernst & Young LLP ("**EY**") are the auditors for the Corporation. EY have been the Corporation's auditors since April 12, 2011. Fees incurred with EY for audit and non-audit services in the last two fiscal years are outlined in the following table:

Nature of Services	Fees Paid to Auditor in Year Ended December 31, 2017 ($)	Fees Paid to Auditor in Year Ended December 31, 2016 ($)
Audit Fees(1)	99,800	99,800
Audit-Related Fees(2)	33,100	34,700
Tax Fees(3)	7,000	2,500
All Other Fees(4)	4,100	3,100
Total	144,000	140,100

Notes:
(1) "Audit Fees" include fees necessary to perform the annual audit of Storm's consolidated financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.
(2) "Audit-Related Fees" for assurance and related services that are reasonably related to the performance of the audit or review of Storm's consolidated financial statements and are not reported as audit fees. Services provided in this category include non-audit reviews of interim financial statements, due diligence assistance, and accounting consultations on proposed transactions.
(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice.
(4) "All Other Fees" include all other non-audit services.

Reliance on Exemptions

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on an exemption from NI 52-110, in whole or in part, granted under Part 8 of NI 52-110 (securities regulatory authority exemption).

Audit Committee Oversight

Since the commencement of Storm's most recently completed financial year, there has not been a recommendation of the Audit Committee to nominate or compensate an external auditor which was not adopted by the Board of Directors.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

The InSite Report evaluated Storm's natural gas and NGL reserves. Storm has no crude oil reserves. The InSite price forecast effective December 31, 2017 was used to determine all estimates of future net revenue. The tables below are a summary of Storm's natural gas and NGL reserves and the net present value of future net revenue attributed to such reserves as evaluated in the InSite Report based on forecast price and cost assumptions. The tables summarize the data contained in the InSite Report and as a result may contain slightly different numbers than the InSite Report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest expense and general and administrative costs, but after providing for estimated royalties, transportation costs, operating costs, development costs, future capital expenditures, and well abandonment costs for only those wells assigned reserves by InSite. The net present value is stated both before and after future income tax. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by InSite represents the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of Storm's natural gas and NGL reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The InSite Report is based on certain factual data supplied by the Corporation and InSite's opinion of reasonable practice in the industry, including requirements under NI 51-101. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain or otherwise known to InSite) were supplied by the Corporation to InSite and accepted without any further investigation. InSite accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data – Forecast Prices and Costs

Summary of Oil and Gas Reserves

	Gross Reserves			**Net Reserves**		
	Conventional Natural Gas	Natural Gas Liquids	6:1 Oil Equivalent	Conventional Natural Gas	Natural Gas Liquids	6:1 Oil Equivalent
	(Mmcf)	(Mbbls)	(Mboe)	(Mmcf)	(Mbbls)	(Mboe)
Proved						
Developed Producing	167,747	5,771	33,729	137,948	4,719	27,710
Developed Non-Producing	3,706	92	710	2,895	70	553
Undeveloped	314,872	10,700	63,179	261,702	8,954	52,571
Total Proved	486,325	16,563	97,617	402,545	13,743	80,834
Probable	156,390	5,281	31,346	125,525	4,288	25,209
Total Proved plus Probable	642,715	21,844	128,963	528,070	18,031	106,043

Numbers in this table may not add due to rounding.

Net Present Value of Future Net Revenue of Oil and Gas Reserves

	Before Future Income Tax and Discounted at					**Unit Value Using Net Reserves**
	0%	5%	10%	15%	20%	Discounted at 10%/year
	($M)	*($M)*	*($M)*	*($M)*	*($M)*	*($/BOE)*
Proved						
Developed Producing	613,055	476,124	389,465	330,863	289,021	14.05
Developed Non-Producing	7,396	4,839	3,341	2,395	1,763	6.04
Undeveloped	915,449	590,662	399,234	278,439	198,009	7.59
Total Proved	1,535,899	1,071,625	792,040	611,697	488,792	9.80
Probable	658,780	357,091	215,918	141,347	97,907	8.57
Total Proved plus Probable	2,194,678	1,428,716	1,007,958	753,044	586,700	9.51

Numbers in this table may not add due to rounding.

	After Future Income Tax and Discounted at				
	0%	5%	10%	15%	20%
	($M)	*($M)*	*($M)*	*($M)*	*($M)*
Proved					
Developed Producing	576,702	455,976	377,775	323,808	284,617
Developed Non-Producing	5,476	3,661	2,585	1,893	1,419
Undeveloped	677,095	430,687	285,517	194,069	133,346
Total Proved	1,259,272	890,324	665,877	519,770	419,382
Probable	488,035	263,033	157,653	102,008	69,645
Total Proved plus Probable	1,747,307	1,153,356	823,530	621,778	489,027

Numbers in this table may not add due to rounding.

Additional Information Concerning Future Net Revenue – (Undiscounted)

Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Abandonment and Reclamation Costs**	**Future Net Revenue Before Income Tax**	**Income Tax**	**Future Net Revenue After Income Tax**
	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)
Total Proved	3,170,764	490,183	703,128	411,647	29,908	1,535,899	276,627	1,259,272
Total Proved plus Probable	4,374,953	699,409	963,692	481,118	36,056	2,194,678	447,371	1,747,307

Future Net Revenue by Product Type (after deduction of royalties, operating costs and future development capital)

		Future Net Revenue Before Income Taxes (Discounted at 10%) ($M)	**Unit Value Using Net Reserves ($)**
Proved	Conventional Natural Gas	792,040	1.63/Mcf
Proved Plus Probable	Conventional Natural Gas	1,007,958	1.59/Mcf

Future net revenues from conventional natural gas excludes solution gas but includes the value of NGL. Unit values above are after royalties, operating costs and future development capital.

Pricing Assumptions – Forecast Prices and Costs

InSite employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2017 in estimating the Corporation's reserves data using forecast prices and costs (before deduction of transportation costs).

	Conventional Natural Gas		**Light and Medium Crude Oil**		**Natural Gas Liquids**			
Year	Henry Hub	AECO-C Spot	WTI @ Cushing	EDM Ref Price	Butane	Propane	Inflation Rate	CDN/U.S. Exchange Rate
	($U.S./Mmbtu)	($Cdn/Mmbtu)	($U.S./Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	(%/yr)	($U.S./$Cdn)
2018	3.10	2.52	60.00	71.36	51.38	35.68	0%	0.79
2019	3.30	2.93	62.50	73.44	52.88	36.72	2%	0.80
2020	3.50	3.22	65.00	75.47	54.34	35.85	2%	0.81
2021	3.70	3.51	70.00	80.49	57.96	36.22	2%	0.82
2022	3.90	3.75	72.50	82.38	59.31	37.07	2%	0.83
2023	4.05	3.85	75.00	84.22	60.64	37.90	2%	0.84
2024	4.20	3.95	77.50	86.01	61.93	38.70	2%	0.85
2025	4.35	4.11	80.00	88.85	63.97	39.98	2%	0.85
2026	4.50	4.27	81.60	90.62	65.25	40.78	2%	0.85
2027	4.59	4.35	83.23	92.43	66.55	41.60	2%	0.85
2028	4.68	4.44	84.90	94.28	67.88	42.43	2%	0.85
Thereafter +2% per annum								

	2017 Actual Price and Forecast InSite Future Prices Storm Wellhead Gas Price (Cdn$/Mcf)	2017 Actual Price and Forecast InSite Future Prices Storm Wellhead NGL Price (Cdn$/Bbl)
2017 Actual(1)	2.58	46.38
2018(2)	2.81	52.82
2019(2)	3.36	57.75
2020(2)	3.54	59.84
2021(2)	3.76	63.99
2022(2)	3.99	65.66

Notes:

(1) 2017 actual wellhead price excludes hedging gains/losses and is after deduction of transportation costs.
(2) InSite forecast prices are after deduction of transportation costs.

Reconciliations of Changes in Reserves

The following sets out the reconciliation of Storm's gross reserves based on forecast prices and costs by principal product type:

	Conventional Natural Gas			Natural Gas Liquids		
Factors	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved + Probable (Mmcf)	Gross Proved Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)
December 31, 2016	390,517.9	138,590.8	529,108.7	12,010.7	3,996.6	16,007.3
Discoveries	-	-	-	-	-	-
Extensions & Improved Recoveries	83,179.0	14,678.3	97,857.3	2,826.5	499.1	3,325.6
Technical Revisions	48,842.3	13,440.3	62,282.7	2,807.7	787.5	3,595.2
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(7,554.0)	(10,320.0)	(17,874.0)	(12.1)	(2.6)	(14.7)
Production	(28,660.1)	-	(28,660.1)	(1,069.6)	-	(1,069.6)
December 31, 2017	486,325.1	156,389.5	642,714.6	16,563.2	5,280.6	21,843.8

Numbers in this table may not add due to rounding.

Additional Information Relating to Reserves Data

The following discussion generally describes the basis on which the Corporation attributes proved and probable undeveloped reserves and the Corporation's plans for developing those undeveloped reserves.

Proved and Probable Undeveloped Reserves

Proved undeveloped reserves are generally those reserves that can be estimated with a high degree of certainty and will be recovered from known accumulations where a significant expenditure is required to render them capable of production.

The following table discloses, for each product type, the volumes of gross proved undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	Conventional Natural Gas (Mmcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end
Prior	130,476.7	222,301.2	4,068.2	6,560.5
December 31, 2015	74,756.9	258,522.1	2,490.1	8,349.2
December 31, 2016	26,166.5	255,980.2	821.2	7,815.3

December 31, 2017	67,328.2	314,872.4	2,287.9	10,699.8

Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	**Conventional Natural Gas (Mmcf)**		**Natural Gas Liquids (Mbbls)**	
	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end
Prior	26,556.2	84,453.3	856.1	1,788.4
December 31, 2015	22,695.3	71,924.8	724.5	2,097.1
December 31, 2016	11,619.7	66,873.6	370.6	1,842.8
December 31, 2017	-	69,344.8	-	2,362.1

Proved and probable undeveloped reserves are determined by InSite based on accepted engineering and geological practices as defined under NI 51-101. These practices included the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information and the optimization of existing fields. The Corporation is focusing capital investment in 2018 on high NGL content natural gas prospects in the Umbach area of northeast British Columbia.

In general, proved plus probable undeveloped reserves are planned to be developed over the next five years based on available forecast net operating income using the December 31, 2017 InSite future price forecast. It is possible that it could take longer to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to lower commodity pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as accelerated depletion); (iii) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (iv) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*" in this AIF.

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 become available and as economic conditions affecting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Corporation's reserves are evaluated by InSite, an independent engineering firm.

As circumstances change and additional data become 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, technology changes, new geological or production information and a changing operating and regulatory environment will affect these estimates. Revisions to reserve estimates can arise from changes in oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs only). At Umbach, there are 66 net future horizontal drilling locations included in the proved category and 78.6 net locations included in the proved plus probable category.

Year	Forecast Prices and Costs	
	Proved	Proved Plus Probable
	($M)	($M)
2018	60,050	64,300
2019	103,071	119,391
2020	179,781	207,352
2021	68,745	90,075
2022	-	-
Total Undiscounted	411,647	481,118
Total Discounted at 10% per year	340,908	395,976

($million)	2017	2016	2015
1P FDC	412	413	435
2P FDC	481	524	543

The Corporation typically relies on two sources of funding to finance its future development costs: (i) internally generated funds flow; and (ii) bank financing when the Corporation's asset base can be used as collateral for bank borrowings. The Corporation considers that these sources are sufficient to fund the future development costs disclosed above using the December 31, 2017 InSite future price forecast.

In 2018, Storm plans to drill three to 12 gross horizontal wells (3.0 – 12.0 net) and complete 11 to 17 horizontal wells (11.0 – 17.0 net) with 11 to 16 gross horizontal wells estimated to start production (11.0 – 16.0 net) during the year, all in the Umbach area of northeast British Columbia.

The Corporation expects to fund its total 2018 capital program with internally generated funds flow and debt. Quarterly fluctuations in sources of funding are expected.

Interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. Storm does not anticipate that interest or other funding costs would make development of any of the oil and gas assets uneconomic.

Oil and Gas Properties

Summarized information about Storm's operations and principal operating areas, properties and operations is as follows:

Umbach, Northeast British Columbia

Storm's land holdings as at December 31, 2017 in the Montney formation total 110,000 net acres, or 155 net sections. Production in 2017 averaged 15,792 Boe per day (81% natural gas and 19% NGL). All of Storm's $81.7 million gross capital investment in 2017 was invested in Umbach. Two project areas have been identified with Umbach North consisting of 20 net sections of jointly owned lands with an average Storm working interest of approximately 60%, and Umbach South, including Nig, consisting of 135 net sections of land at a 100% working interest as at December 31, 2017.

In 2017, 16 Montney horizontal wells (16.0 net) were drilled, 12 horizontal wells (12.0 net) were completed and 13 horizontal wells (13.0 net) started production.

Start-up of Storm's third field compression facility occurred in January 2017, with initial capacity of 35 Mmcf per day of raw gas, which is expandable to 70 Mmcf per day. Storm now operates three 100% working interest field compression facilities that have total capacity of 115 Mmcf per day. Upon expansion of the third field compression facility, Storm's capacity would increase to 150 Mmcf per day which supports growth in corporate production to approximately 27,000 Boe per day.

Grande Prairie Area, Northwest Alberta

Production in 2017 averaged approximately 60 Boe per day. Following the 2015 Grande Prairie disposition, there remains one property in the Grande Prairie area. No capital was invested on this property by the Corporation in 2017 and no activity is planned for 2018.

Horn River Basin, Northeast British Columbia

Storm, through a predecessor company, began acquiring undeveloped land in the HRB in 2008 in partnership with SGR (40% Storm, 60% SGR). As at December 31, 2017, Storm has a 100% working interest in 119 sections in the HRB (80,000 net acres) which is prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Storm's one horizontal well averaged 77 Boe per day in the fourth quarter of 2017. Cumulative production to date from this well is approximately 5.8 Bcf raw. A core area totaling 30 sections (100% working interest) has been proven to be productive with this producing horizontal well plus two vertical wells that were completed with final test rates of 900 Mcf per day over the final 24 hours of each flow test. Lands within the 30 section area have been continued through drilling and are not subject to expiry. The remaining 89 sections may be subject to expiry over a period of several years beginning in 2020.

Oil and Gas Wells

The following table summarizes the Corporation's interest as at December 31, 2017 in wells that are producing and non-producing. All of the wells in which Storm has an interest are located onshore in the Provinces of Alberta and British Columbia.

	Producing Wells				**Non-Producing Wells**			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
British Columbia	-	-	60.0	56.4	-	-	29.0	24.9
Alberta	-	-	1.0	1.0	4.0	3.2	12.0	9.6
Total	-	-	61.0	57.4	4.0	3.2	41.0	34.4

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which the Corporation has an interest at December 31, 2017 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 of December 31, 2017.

	Gross Acres	**Net Acres**	**Net Acres Expiring Within One Year**
Umbach Montney - BC	121,180	110,087	-
Horn River Basin - BC	81,115	79,528	-
Grande Prairie - AB	12,640	9,411	-
Other areas	54,955	46,318	-
Total	269,890	245,344	-

Notes:

(1) "**Gross**" in this chart means the total number of acres in which the Corporation holds an interest.
(2) "**Net**" in this chart means the aggregate of the percentage working interests of Storm in the gross acres.

The pace of development of these unproved properties is subject to capital allocation constraints and is influenced by many factors, including the results of exploration and development activities of Storm and others in the area, infrastructure capacity constraints and Storm's short-term and long-term view of oil and natural gas prices. Storm currently has no material work commitments on lands with no attributed reserves.

Forward Contracts

Storm is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by Storm to reduce its exposure to fluctuations in commodity prices and foreign exchange rates.

Commodity price hedges are used to support longer term growth by providing some stability regarding future revenue and funds flow. The objective is to hedge 50% of most recent quarterly or monthly production for the next 12 months and 25% for the following 13 to 24 months. Anticipated production growth is not hedged.

Details of commodity price contracts in respect of Storm's hedging activities can be found in Note 14, "Financial Instruments", to Storm's audited consolidated financial statements for the year ended December 31, 2017 which have been filed on SEDAR (www.sedar.com). See "*Risk Factors*" for additional information on the risks and uncertainties relating to Storm's hedging activities.

Tax Horizon

As at December 31, 2017, the Corporation had resource pools and operating losses of approximately $479 million available for deduction against future taxable income. These existing pools, plus pool additions through the Corporation's capital program in 2018 and beyond, mean that the Corporation does not expect to pay income tax for a considerable number of years unless commodity prices show material improvement from what was realized in 2017. However, measurement of losses and tax pools and their availability can be subject to audit and reassessment by Canada Revenue Agency, potentially several years later.

Costs Incurred

The following table summarizes the Corporation's gross property acquisition costs, exploration costs and development costs for the year ended December 31, 2017.

Capital Investment ($M)

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Costs ($M)	-	-	1,838	79,847

Exploration and Development Activities

The following table summarizes the gross and net exploration and development wells in which the Corporation participated during the year ended December 31, 2017.

	Development Wells		**Exploration Wells**		**Total Wells**	
	Gross	Net	Gross	Net	Gross	Net
Natural gas wells	15.0	15.0	1.0	1.0	16.0	16.0
Oil wells	-	-	-	-	-	-
Service wells	-	-	-	-	-	-
Stratigraphic test wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	15.0	15.0	1.0	1.0	16.0	16.0

During 2018, the Corporation will focus on further development in the Umbach area of northeast British Columbia. Subject to the availability of capital, Storm intends to drill three to 12 gross horizontal wells (3.0 – 12.0 net), complete 11 to 17 gross horizontal wells (11.0 – 17.0 net), and anticipates 11 to 16 gross wells (11.0 – 16.0 net) starting production during the year, all in the Umbach area.

Production Estimates

Gross – Production by Product

The following tables disclose for each product type the total volume of production estimated by InSite for 2018 based on the Corporation's reserves and ownership at December 31, 2017.

2018	**Conventional Natural Gas** (Mmcf)	**Natural Gas Liquids** (Mbbls)	**Boe/d**
Proved			
Umbach	37,770.8	1,401.4	21,086
HRB	272.3	-	124
Grande Prairie	124.3	0.3	58
Total Proved	38,167.4	1,401.7	21,268
Proved Plus Probable			
Umbach	38,171.8	1,421.3	21,324
HRB	279.2	-	127
Grande Prairie	126.9	0.3	59
Total Proved Plus Probable	38,577.9	1,421.6	21,510

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below. Note that for the purposes of the two tables below, "Condensate" is field condensate and pentane recovered at gas plants, and "NGL" is propane and butane recovered at gas plants.

	2017 Quarter Ended			
	Q4 Dec. 31	**Q3** Sept. 30	**Q2** June 30	**Q1** March 31
Average Daily Production[1]				
Conventional Natural Gas (Mcf/d)	87,375	74,318	68,308	84,093
Condensate (Bbls/d)	1,914	1,600	1,468	1,758
NGL (Bbls/d)	1,460	1,206	1,138	1,174
Combined (Boe/d)	17,936	15,193	13,991	16,947
Average Price Received[1][3]				
Conventional Natural Gas ($/Mcf)	2.26	2.02	2.81	3.23
Condensate ($/Bbl)	69.53	53.52	57.65	64.40
NGL ($/Bbl)	33.29	21.66	20.45	23.09
Combined ($/Boe)	21.12	17.23	21.45	24.29
Royalties Paid				
Conventional Natural Gas ($/Mcf)	0.05	(0.04)	(0.15)	(0.22)
Condensate ($/Bbl)	(5.96)	(4.86)	(5.41)	(5.98)
NGL ($/Bbl)	(2.99)	(1.66)	(1.97)	(2.46)
Combined ($/Boe)	(0.63)	(0.85)	(1.47)	(1.88)
Operating & Transportation Expenses				
Conventional Natural Gas ($/Mcf)	(1.22)	(1.29)	(1.45)	(1.26)
Condensate ($/Bbl)	(4.09)	(3.35)	(6.87)	(2.72)
NGL ($/Bbl)	-	-	-	-
Combined ($/Boe)	(6.37)	(6.67)	(7.81)	(6.53)

	2017 Quarter Ended			
	Q4 Dec. 31	Q3 Sept. 30	Q2 June 30	Q1 March 31
Netback Received(2)(3)				
Conventional Natural Gas ($/Mcf)	1.09	0.69	1.21	1.75
Condensate ($/Bbl)	59.48	45.31	45.36	55.70
NGL ($/Bbl)	30.30	19.99	18.48	20.63
Combined ($/Boe)	14.11	9.72	12.17	15.88

Notes:

(1) Before deduction of royalties.
(2) Netbacks are non-GAAP measurements and are calculated by subtracting royalties, operating and transportation costs from revenues.
(3) Before hedging activities.

The following table sets out the production volumes for each of Umbach, HRB and Grande Prairie for the year ended December 31, 2017:

	Conventional Natural Gas (Mcf/d)	Condensate (Bbls/d)	Natural Gas Liquids (Bbls/d)
Umbach	77,175	1,684	1,245
HRB	993	-	-
Grande Prairie	353	1	-
Total	78,521	1,685	1,245

DIVIDENDS AND DISTRIBUTIONS

The Corporation has not declared or paid any dividends on its Common Shares since incorporation on June 8, 2010. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of Storm consists of an unlimited number of Common Shares and an unlimited number of first preferred shares (the "**First Preferred Shares**"), issuable in series. As at March 29, 2018, an aggregate of 121,556,812 Common Shares were issued and outstanding and no First Preferred Shares were issued or outstanding.

The following is a summary of the rights, privileges, restrictions and conditions that attach to the Common Shares and the First Preferred Shares.

Common Shares

Storm is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote per share at meetings of holders of Common Shares, to receive dividends if, as and when declared by the Board of Directors and to receive pro rata the remaining property and assets of Storm upon its dissolution or winding up, subject to the rights of shares having priority over the Common Shares.

First Preferred Shares

Storm is authorized to issue an unlimited number of First Preferred Shares without nominal or par value. First Preferred Shares have priority over Common Shares in the event of liquidation, dissolution or winding up of the Corporation.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the symbol “SRX”. The following table sets forth the price range and trading volume of these securities as reported by the TSX or the TSXV, as applicable, for the period January 1, 2017 to December 31, 2017.

Month	High ($)	Low ($)	Volume
January 2017	5.33	4.07	2,889,551
February 2017	4.55	4.00	1,519,584
March 2017	4.42	3.60	2,051,767
April 2017	4.64	3.75	1,126,436
May 2017	4.20	3.60	3,222,955
June 2017	4.20	3.75	2,226,777
July 2017	4.17	3.67	1,104,030
August 2017	4.11	3.25	642,716
September 2017(1)	3.70	3.25	1,792,517
October 2017	3.60	3.14	431,197
November 2017	3.76	2.46	2,201,201
December 2017	2.92	2.41	2,397,526

Note:

(1) On September 27, 2017, the Common Shares commenced trading on the TSX and were concurrently delisted from the TSXV.

PRIOR SALES

The following table summarizes the issuance of securities convertible into Common Shares during the year ended December 31, 2017.

Date of Issuance	Description of Transaction	Number and Type of Securities	Price per Security
January 7, 2017	Grant of Options	40,000 Options	$5.27
March 1, 2017	Grant of Options	105,000 Options	$4.15
April 1, 2017	Grant of Options	105,000 Options	$4.15
June 1, 2017	Grant of Options	40,000 Options	$3.91
August 8, 2017	Grant of Options	30,000 Options	$4.10

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulation 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 British Columbia, all of which should be carefully considered by investors. Within the knowledge of management, it is not expected that any of these controls or regulations will affect the operations of the Corporation in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing in Canada

Natural Gas

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

Natural Gas Liquids

The price of condensate and other NGL sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGL, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers, which results in the market determining the price of crude oil. Worldwide supply and demand factors primarily determine crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Exports from Canada

Crude oil, natural gas and NGL exports from Canada are subject to the *National Energy Board Act* (Canada) (the "**NEB Act**") and the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGL exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the NEB is required, which is no longer the case for natural gas and NGL. For natural gas and NGL, the NEB uses a written process that includes a public comment period for affected persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGL), the maximum term is 25 years. All crude oil, natural gas and NGL licences require the approval of the cabinet of the Canadian federal government.

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGL) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the federal government.

Storm does not directly enter into contracts to export its production outside of Canada.

The government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

One major constraint to the export of crude oil, natural gas and NGL outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline or other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and political factors. The transportation capacity deficit is not likely to be resolved quickly given the significant length of time required to complete major pipeline or other transportation projects once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGL in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Furthermore, recent years have seen the emergence of new sources of supply as natural gas deposits formerly regarded as inaccessible, particularly those locked in shales and other tight formations, both in Canada and the U.S., are now being exploited through new drilling and fracturing applications. From 2009 onwards, increased supply of natural gas from these sources has exceeded the growth in demand with the result being a decrease in the price for natural gas. The effect on natural gas supply, as production of shale and other tight gas matures, cannot be determined, but the contribution of shale gas to aggregate supply will likely have a continuing and considerable influence on natural gas pricing, at least in the short and medium term.

From 2009 through to 2018, Pacific Rim countries, particularly China, Japan and South Korea, through sovereign oil companies, or representatives of end users, have expressed interest in or invested in, infrastructure projects to export LNG, and exploration and development activities in Canada, with a view to securing sources of future supply. LNG export projects have a long lead time, but if consummated, may result in Canada becoming a significant exporter of liquefied natural gas to the Pacific Rim, as an additional or successor market to the U.S. It may also lead to future internationalization of pricing for natural gas.

Strong U.S. and Canadian gas production growth, ample inventories and reduced heating demand are expected to keep the North American market amply supplied and could keep prices soft for most of 2018.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada - U.S. Free Trade Agreement. 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 domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements.

The administration in the United States has initiated a renegotiation of NAFTA, the effect of which on the oil and gas industry is uncertain. Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. As of the date hereof, renegotiation discussions continue and the outcome of such negotiations remains unclear. As the United States remains Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGL from Canada, any changes to, or termination of, NAFTA could have an effect on Western Canada's crude oil and natural gas industry, including the Corporation's business.

Canada and ten other countries recently concluded discussions with respect to the Comprehensive and Progressive Agreement for Trans-Pacific Partnership (the "**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The text of CPTPP has been finalized and published, but the agreement remains subject to ratification by the governments of each of the countries involved.

Canada has also pursued a number of other international free trade agreements with countries around the world. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017.

While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Extractive Sector Transparency Measures Act

The Extractive Sector Transparency Measures Act ("**ESTMA**"), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state owned entities, including employees and public office holders, made by 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 were exempt from reporting obligations until June 1, 2017. Failure to comply with the reporting obligations under ESTMA is 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 which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a factor in the profitability of crude oil, NGL, sulphur and natural gas production. Royalties payable on production from minerals other than Crown-owned minerals are determined by negotiations between the mineral owner and the lessee although production from such lands is subject to certain provincial taxes and royalties. 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 well productivity, incentive programs, year drilled and the type or quality of the petroleum product produced.

From time to time, the provincial governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty reductions, royalty holidays and credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of oil, natural gas and NGL.

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

British Columbia

Producers of natural gas and NGL in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGL and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. Furthermore, a minimum royalty rate applies for natural gas. For NGL and condensates, the royalty rate is fixed at 20%.

The royalty calculation for producers of crude oil in British Columbia takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

The royalties payable by each producer will thus vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

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

Alberta

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a drilling and completion cost allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the AER on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the drilling and completion cost allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the drilling and completion cost allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 meters deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGL is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

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

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned 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 British Columbia 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”, introduced in October of 2007 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. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. 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 additional shallow rights reversion notices.

Environmental Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to evolving national, provincial and municipal laws and regulations, as well as, potentially, international conventions. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced in association with oil and gas operations, habitat protection and minimum setbacks of oil and gas activities from fresh water bodies. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines, penalties and sanctions, some of which may be material or materially affect the Corporation's operations. Certain environmental protection legislation may subject the Corporation to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault need not be established by claimants affected by such a spill or discharge. Further, as Canadian environmental legislation evolves, the use of administrative penalties by the imposition of fines for the commission of environmental offences on an absolute liability basis has grown.

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

On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator ("**CER**"). Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. Additional categories of projects may be included within new impact assessment process, such as largescale wind power facilities and in-situ oil sands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (a) early engagement by proponents to engage the Agency and all stakeholders, such as the public and indigenous groups, prior to the formal impact assessment process; (b) potentially increased public participation where the project undergoes a panel review; (c) providing analysis of the potential effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (d) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic effects; and (e) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. Many of the CER's activities would be similar to the NEB, but with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The effects of the proposed regulatory scheme remains unclear.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

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

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

In British Columbia, energy projects may be subject to review pursuant to the provisions of the *Environmental Assessment Act* (British Columbia), which rolls the previous processes for the review of major energy projects into a single environmental assessment process that contemplates public participation in the environmental review. Other environmental protection and management measures, including reclamation, are governed by the *Oil and Gas Activities Act* (British Columbia) and the *Environmental Management Act* (British Columbia).

The oil and gas industry is subject to such environmental regulations which include restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. 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.

As of December 31, 2017, the Corporation owned approximately 106 gross and 95 net wells for which abandonment and reclamation costs are expected to be incurred. As disclosed in the Corporation's audited consolidated financial statements for the year ended December 31, 2017, the total undiscounted amount required to settle the Corporation's future asset retirement obligations, including environmental remediation, is estimated to be $36.3 million. The Corporation estimates abandonment and reclamation costs by taking account of the costs associated with decommissioning, abandonment, remediation and reclamation, all adjusted according to the Corporation's working interest and appropriately discounted. Such costs are individually attributed to assets then aggregated to determine the total liability and are not reduced by salvage values.

Liability Management Rating Programs

British Columbia

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

In British Columbia, the British Columbia Oil and Gas Commission administers a Liability Management Rating Program (the "**LMR Program**"), the purpose of which is to ensure that permit holders for upstream oil and gas wells, facilities and pipelines are responsible for the financial risks related to their operations. Updated as of June 2016, the LMR Program aids in determining the security deposits required by permit holders to protect against those who may not be capable of meeting abandonment and reclamation obligations. The LMR Program is used to identify permit holders whose liabilities exceed assets (permit holders with a calculated ratio of deemed assets to deemed liabilities of less than 1.0), and it requires that said permit holders take action to mitigate any financial risks represented by the difference in the calculation. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the British Columbia Oil and Gas Commission.

Alberta

In Alberta, the AER similarly administers the Licensee Liability Rating Program (the "**LLR Program**") as part of the Liability Management Rating Assessment Process. The LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The OGCA 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 LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the LLR Program through a levy administered by the AER. The 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 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 June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 16**") in an urgent response to a decision from the Alberta Court of Queen's Bench, which was affirmed by a majority at the Alberta Court of Appeal. In Redwater Energy Corporation (Re), 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the *Oil and Gas Conservation Act* (Alberta) and the *Bankruptcy and Insolvency Act* ("**BIA**"), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. The decision is currently under appeal to the Supreme Court of Canada, with final decision expected in 2018.

The AER issued several bulletins in response to Redwater. Bulletin 16 provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. The AER's Directive 067 was amended and now requires extensive corporate governance and shareholder information, with a focus on any previous insolvency proceedings in order to acquire or transfer licenses needed to operate wells and facilities. The AER will consider and process all applications for licence eligibility under Directive 067: Applying for Approval to Hold EUB Licences as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licensee eligibility approval if appropriate in the circumstances. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer. The AER may implement additional changes in response to the final Redwater decision.

The AER implemented the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013. 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 is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19% of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

International and Domestic Regulations

Federal

In common with all producers, the Corporation's exploration activities and production facilities emit carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases".

Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**"), which was entered into in order to work towards stabilizing atmospheric concentrations of GHG emissions at a level to prevent "dangerous anthropogenic interference with the climate system". The UNFCCC came into force on March 21, 1994. Subsequent international negotiations led to the Kyoto Protocol, an international treaty which extends the UNFCCC and commits its signatories to reduce GHG emissions. The Kyoto Protocol was adopted in December 1997 and came into force on February 16, 2005. Canada withdrew from the Kyoto Protocol effective December 2012. On December 12, 2015, the UNFCCC adopted the Paris Agreement, which Canada ratified on October 5, 2016. Under the Paris Agreement, countries have also committed to an ambitious goal of holding the increase in global average temperature to well below 2 degrees Celsius above pre-industrial levels, while they pursue efforts to limit the temperature increase to 1.5 degrees Celsius above pre-industrial levels. In 2018, members of the Paris Agreement launched the Talanoa dialogue in order to assess the members' collective efforts and progress with respect to the long term goal to peak global GHG emissions, and subsequently achieve net zero emissions. The Paris Agreement is a significant departure from the 2009 Copenhagen Accord, and contains a number of binding and non-binding commitments, including a long-term emissions goal of peaking global greenhouse gas "as soon as possible" to achieve balance between anthropogenic emissions by sources and removal of GHG emissions by sinks in the second half of the century. This means reaching net zero emissions after 2050; however, there is no corresponding timeline or details about how the delayed peak by developing countries will be balanced.

In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC Secretariat, pledging a 30% reduction from 2005 levels – approximately 523 megatonnes – by 2030. In addition, provincial/territorial and federal leaders met and agreed that they would work together to build a national climate change plan. At a follow-up meeting of the First Ministers and Prime Minister on March 3, 2016, the parties agreed under the Vancouver Declaration on Clean Growth and Climate Change to launch a process to develop the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"), which was released on December 9, 2016 at the First Ministers meeting. Saskatchewan was the only province that decided not to adopt the Framework. Prior to the release of the Framework, the federal government announced in October 2016 that it will set a minimum price on carbon starting at $10 per tonne in 2018, which will increase by $10 per year until it reaches $50 per tonne by 2022. This approach will be reviewed in 2022 to confirm the path forward, including continued increases in stringency. Under the federal plan, each province and territory will be required to implement carbon pricing in its jurisdiction by 2018, whether in the form of a carbon tax or a cap-and-trade system. If the carbon price in a jurisdiction does not meet the federal minimum price, the federal government will step in and impose a carbon price that makes up the difference and return the revenue to the province or territory. In addition, provincial and territorial goals for reducing emissions must be at least as stringent as federal targets. Currently, four provinces representing more than 80% of Canada's population (Ontario, Québec, Alberta and British Columbia) have carbon pricing in place that meets the federal benchmark.

In May 2017, Environment and Climate Change Canada ("**ECCC**") released its *Technical Paper on the Federal Carbon Pricing Backstop*, which was followed by the *Guidance on the Pan-Canadian Carbon Pollution Pricing Benchmark* in August 2017. In December 2017, *Supplemental Benchmark Guidance* was issued and federal Environment Minister Catherine McKenna and Finance Minister Bill Morneau announced a deadline of September 1, 2018 for each province to outline how it is implementing a carbon pricing system that meets the federal standard (the federal government has requested that provinces and territories that choose the federal backstop, in whole or in part, confirm this by March 30, 2018). The federal government will then determine whether the planned systems are on track to meet the standard, or whether the federal approach should be applied in that jurisdiction. On January 15, 2018, ECCC released draft legislative proposals for public comment relating to the proposed *Greenhouse Gas Pollution Pricing Act* and the proposed regulatory framework for the output-based pricing system (which is designed to minimize competitiveness risks for emissions-intensive, trade-exposed industrial facilities). The comment periods for the federal carbon pricing backstop legislation and the regulatory framework end on February 12, 2018 and April 9, 2018, respectively.

On May 27, 2017, the federal government published draft regulations to reduce emissions of methane from the crude oil and natural gas sector. The proposed regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes, by introducing new control measures. Among other things, the proposed regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

In December 2017, ECCC published its updated requirements and step-by-step reporting instructions in advance of the 2017 reporting period under the federal *Greenhouse Gas Reporting Program* ("**GHGRP**"). The Notice with respect to reporting of greenhouse gases for 2017, which was published on December 30, 2017 in Part I of the *Canada Gazette,* outlines the 2017 reporting requirements for GHG-emitting facilities. In December 2017, ECCC published its updated requirements and step-by-step reporting instructions in advance of the 2017 reporting period under the GHGRP. Stakeholders should note that for the 2017 reporting year under the GHGRP, the reporting threshold has been lowered from 50,000 tonnes to 10,000 tonnes of carbon. All facilities that emitted the equivalent of 10,000 tonnes of carbon in 2017 will be required to submit a report by June 1, 2018.

In November 2016, the federal government announced that it would commence development of a performance-based clean fuel standard ("**CFS**") that would incent the use of a broad range of low carbon fuels, energy sources and technologies. The objective of the CFS is to achieve 30 megatonnes of annual reductions in GHG emissions by 2030, as part of efforts to achieve Canada's commitments under the Paris Agreement. On December 13, 2017, ECCC published a regulatory framework on the CFS, which outlines the key design elements for the CFS regulation, including its scope, regulated parties, carbon intensity approach, timing, and potential compliance options such as credit trading. Draft CFS regulations are expected to be published in late 2018.

The Corporation will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions. It is uncertain what effect this action will have on the long and medium term business of the Corporation. However, the stance of the current government, both federally and provincially, may result in public policy evolving in a fashion more accommodating to the intent of the Paris Agreement. Further, there is considerable and increasing opposition, both domestic and international, to the extraction of crude oil from oil sands in Alberta which may have an indirect effect on the Corporation's operations as oil sands operations use natural gas as an energy source and certain NGL are used as a diluent when crude oil from oil sands is pipelined. The uncertainty surrounding the construction of the Keystone XL Pipeline and opposition to expanding the Trans Mountain Pipeline to tidewater, if successful, may result in the industry being unable to access international markets for its products.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. Additionally, British Columbia seeks to generate at least 93% of its electricity from clean or renewable sources and build the infrastructure necessary to transmit it. The legislation established no date for this target.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30/tonne. However, in its September update to the 2017/2018 Budget, the Government signalled raising the carbon tax to $35/tonne in April 2018 with subsequent increases expected annually, reaching the federal target carbon price of $50/tonne on April 1, 2021.

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

The British Columbia legislation applies directly to the Corporation's operations and is expected to have an effect on operating expenses and economic returns as changes are implemented and/or phased in.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with the federal legislation. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

The *Carbon Competitiveness Incentives Regulation* (the "**CCIR**"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

The new Alberta legislation does not apply directly to any of the Corporation's facilities and is expected to have a negligible effect on the Corporation's operations and operating expenses.

RISK FACTORS

An investment in the Corporation should be considered speculative due to the nature of the Corporation's involvement in the acquisition, exploration, development, production and marketing of oil and natural gas and due to its current stage of development. Oil and gas operations involve many risks which even a combination of experience and knowledge and careful project management may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation or that existing oil and gas reserves owned by the Corporation can be profitably produced and sold.

Oil and Gas Prices and General Economic Conditions

The Corporation's results of operations and financial condition are dependent on the prevailing prices of crude oil and natural gas. Crude oil and natural gas prices are subject to fluctuations in supply, demand, market uncertainty and other factors that are beyond the Corporation's control. This can include but is not limited to: the global and domestic supply of and demand for crude oil and natural gas; global and North American economic conditions; the actions of OPEC or individual producing nations; government regulation; political stability; the ability to transport commodities to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. In addition, significant growth in crude oil and natural gas production in Western Canada and the United States has resulted in pressure on transportation and pipeline capacity which contributes to fluctuations in prices. All of these factors are beyond the Corporation's control and can result in a high degree of price volatility.

Fluctuations in currency exchange rates further compound this volatility when commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. The Corporation's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges.

Fluctuations in the price of commodities and associated price differentials affect the value of the Corporation's assets and the Corporation's ability to pursue its business objectives. Prolonged periods of commodity price depression and volatility may also affect the Corporation's ability to meet guidance targets and meet all of its financial obligations as they come due. Any substantial and extended decline in the price of oil and gas could have an adverse effect on the Corporation's reserves, borrowing capacity, revenues, profitability and funds flow and may have a material adverse effect on the Corporation's business, financial condition, results of operations, prospects and the level of expenditures for the development of oil and natural gas reserves. This may include delay or cancellation of existing or future drilling or development programs or curtailment in production.

Any material or sustained decline in commodity prices could result in a reduction of the Corporation's net production revenue and funds flow. The economics of producing from some wells may change as a result of such lower prices, which could result in reduced production of oil or gas and a reduction in the volumes and value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and funds flow and a reduction in its oil and gas acquisition, development and exploration activities.

Crude oil and natural gas prices will fluctuate as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world and national economies, the actions of OPEC or individual producing nations, weather patterns, as well as unforeseeable geopolitical events. Fluctuating oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price fluctuations also make it difficult to budget for and project the economic return on acquisitions and development projects.

In addition, bank borrowings available to the Corporation are, in part, determined by the Corporation's borrowing base. A sustained material decline in commodity prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid, as well as curtailment of the Corporation's investment programs.

The Corporation conducts regular assessments of the carrying amount of its assets in accordance with IFRS. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying amount of the Corporation's assets may be subject to impairment.

Substantial Capital Requirements and Liquidity

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production (including facility acquisition or construction) of oil and natural gas reserves in the future. If the Corporation does not have, or is unable to increase, revenues or reserves in the future, the Corporation may have limited ability to maintain or grow funds flow and to attract the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or funds flow, or from the sale of non-core assets, will be available or sufficient to meet those requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Credit Facility Risk

The current Credit Facility is subject to renewal by April 27, 2018. There is a risk that the Credit Facility will not be renewed for the same amount or on the same terms or that the borrowing base will not be increased as a result of production growth to date and forecasted production growth. Although the Corporation believes that the Credit Facility will be sufficient for its immediate requirements, there can be no assurance that the amount will be adequate for the Corporation's future financial obligations including partially funding its capital expenditure program, or that additional funds will be available under the Credit Facility or from other sources on terms acceptable to the Corporation.

The Corporation is required to comply with its covenants under the Credit Facility. In the event that the Corporation does not comply with its covenants under the Credit Facility, access to the Credit Facility could be restricted or accelerated repayment could be required by its lenders and debt service costs would likely increase. Although the Corporation believes it is in compliance with existing covenants, compliance may not be sustainable or covenants may become increasingly onerous.

Interest Rates

There is a risk that interest rates will increase which would increase debt service costs and decrease funds flow.

Additional Funding Requirements

The Corporation's future funds flow may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional funding in order to carry out its oil and gas acquisition, exploration and development activities. Additional funding could include debt and/or issuing additional equity. Failure to obtain such funding on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's future revenues decrease as a result of lower oil and natural gas prices or otherwise, it may affect the Corporation's ability to attract the necessary funding to increase reserves or to maintain its production. If the Corporation's funds flow is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing or proceeds from asset sales will be available to meet this funding shortfall or will be available on terms acceptable to the Corporation.

To the extent that external sources of funding become limited, unavailable or available only on onerous terms, the Corporation's ability to invest and to maintain existing assets may be impaired and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Based on expected funds flow and bank credit availability, the Corporation believes it has sufficient funds available to support its projected capital expenditures. However, if funds flow is lower than expected or capital costs for these projects exceed current estimates, or if the Corporation incurs major unanticipated expenses related to development or maintenance of its existing properties, it may be required to seek additional funding to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties. The Corporation will also consider selling non-core assets to support investment programs.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

From time to time the Corporation makes acquisitions and dispositions of businesses and assets that occur in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as realizing the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of individual properties and other assets. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Proceeds on the sale of non-core assets may be less than anticipated, affecting the corporation's capital availability.

Royalties

There can be no assurance that the federal government and the provincial governments of Alberta and British Columbia will not adopt new royalty regimes or modify the existing royalty regimes which may have an effect on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's funds flow and could make future capital investments, or the Corporation's operations, less economic. Frequent changes to royalty regimes have created uncertainty surrounding the ability to accurately estimate future royalties and, correspondingly, funds flow, resulting in additional volatility and uncertainty for producers, including the Corporation.

Government Regulation

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

The discharge of oil, natural gas, or other pollutants into the air, soil or water may give rise to liabilities to third parties and may require the Corporation to incur costs to remedy such discharge in the event that they are not covered by the Corporation's insurance. Although the Corporation maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit.

Field operations, including drilling and completions, require regulatory permits, licences, registrations, approvals and authorizations from various levels of the provincial and federal governments. Changes to regulations and/or failure to obtain the required permits, licences, registrations, approvals and authorizations could have a material adverse effect on the Corporation including the financial condition and results of operations.

The Corporation's operations are subject to various federal, provincial and local environmental regulations and laws. Regulations and laws impose restrictions on emissions, spills and releases of various substances used in oil and gas industry operations, requirements for waste handling and storage, habitat protection and the operation, maintenance, abandonment and reclamation of facilities, pipelines and wells. Changes to environmental regulations could delay or prevent planned activity, affect current and forecast production levels and increase the cost of production and/or development capital expenditures.

The Corporation believes it is in material compliance with environmental legislation in the jurisdictions in which it operates at this time. The Corporation's practice is to do all that it reasonably can to ensure that it remains in material compliance with environmental protection legislation. The Corporation also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation.

No assurance can be given that environmental laws will not result in a curtailment of production, a material increase in the costs of production or the costs of development or exploration activities, or otherwise adversely affect the Corporation's financial condition, capital expenditures, results of operations, competitive position or prospects.

Oil and natural gas operations (exploration, drilling, well completions and tie-ins, production, facility operation, distribution, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government which may be amended from time-to-time. The Corporation's oil and natural gas operations are also subject to compliance with federal, provincial and local laws and regulations controlling the discharge of pollutants into the environment or otherwise relating to the protection of the environment. Although the Corporation believes that it is in material compliance with current applicable environmental regulations, changing government regulations may have an adverse effect on the Corporation. See "*Industry Conditions - Environmental Protection Requirements*" and "*Industry Conditions – International and Domestic Regulations*".

Cyber-Security

The Corporation is dependent on information technology, such as computer hardware and software systems, in order to properly operate its business. These systems have the potential for information security risks, which could include potential breakdown, virus, invasion, cyber-attack, cyber-fraud, security breach and destruction or interruption of information technology systems by third parties or insiders. Unauthorized access to these systems could result in interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse effect on the protection of intellectual property and confidential and proprietary information, and on the Corporation's business, financial condition, results of operations and fund flow.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other participants for the acquisition of oil and natural gas properties, for access to third party processing and transportation capacity and in the marketing of oil and natural gas. The Corporation's competitors include companies which have greater financial resources, staff, access to land and facilities than those of the Corporation. The Corporation's future competitiveness will depend not only on its ability to develop its present properties, but also on its ability to identify and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods of delivery and reliability of delivery.

Operating Risks

Oil and natural gas exploration is subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, fluid spills (oil, water, chemicals) and releases of possibly sour natural gas, 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 and fatalities. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable or even identifiable. Although the Corporation maintains liability insurance in an amount which it considers adequate, the potential liability associated with these risks could exceed policy limits, in which event the Corporation 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, the invasion of water into producing formations, inability to access production or facility sites, access to third party pipelines and facilities, pipeline and facilities damage and a range of other risks, some of which may not be foreseeable. In addition, economic conditions may affect the solvency of suppliers, customers and partners, possibly resulting in financial loss and/or operational disruption.

Oil and gas operations are also subject to specific operational risks which may have material operational and financial effect on the Corporation should they occur. This could include drilling into unexpected formations or experiencing unexpected pressures while drilling. In addition, many of the Corporation's wells produce sour gas, which necessitates the use of equipment built to sour gas specifications. In addition to being subject to stringent regulation by the provincial regulator with respect to emergency response plans, public safety and application procedures and requirements, sour gas operations are subject to special control and handling policies which are codified in the Corporation's Corporate Health and Safety Manual.

Hedging Activities

The Corporation may enter into agreements to receive fixed or collared prices on its oil and natural gas production as well as other derivative instruments to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and will record losses from hedging activities based on mark-to-market measurement.

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, during the period of such agreements, the Corporation would not benefit from the changing exchange rate.

Availability of Equipment

Oil and natural gas exploration and development activities are dependent on the availability of drilling, completion and related equipment as well as experienced and competent crews in the particular areas where such activities will be conducted. Demand for equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Further, to the extent the Corporation is not the operator, the Corporation will be dependent on the operator for the timing of activities related to such properties and will be largely unable to direct or control activities.

Environmental Risks

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that the Corporation may be in non-compliance with an environmental law, regulation, or without a necessary permit, licence, or other regulatory approval, possibly unintentionally. Such risks may expose the Corporation to fines or penalties, third party liabilities or to the requirement to terminate operations or remediate, each of which could be material. The operational hazards associated with possible blowouts, accidents, spills, gas leaks, fires, or other damage to a well or a pipeline may require the Corporation to incur costs and delays to undertake corrective actions, and could result in environmental damage or contamination for which the Corporation could be liable for remediation costs and fines imposed by regulatory agencies. Although the Corporation maintains liability insurance consistent with prudent industry practice, the nature of environmental risks is such that they may exceed commercially reasonable insurance coverage. In this event the Corporation could incur significant costs which would be funded from cash resources and which may have an adverse effect on the Corporation's ability to finance future investment or continue in business.

Liability Management

Alberta and British Columbia have developed liability management programs designed to protect taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder can no longer meet its obligations. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The recent Alberta Court of Queen's Bench decision, Redwater, found an operational conflict between the BIA and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the AER to the Supreme Court of Canada for final determination. In response to the decision, the AER issued interim rules to administer the liability management program until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See "*Industry Conditions - Liability Management Rating Programs*".

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are put in place. Some of the Corporation's facilities may be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. Prior to adopting the Paris Agreement, Canada set an INDC target of a 30% reduction from 2005 levels in GHG emissions by 2030. In 2018, Canada along with the other member parties will convene a facilitative dialogue to assess their collective efforts in relation to their progress towards the long-term goal. The outcomes of this dialogue will likely inform future climate policies and actions.

The federal, Alberta and British Columbia governments have implemented legislation to tax carbon emissions which may decrease the demand for oil and natural gas and have increased the Corporation's production costs. Future planned and unplanned increases to carbon taxes may have a material adverse effect on financial results. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with competitors who operate in jurisdictions where there are less costly carbon regulations.

The direct or indirect costs of compliance with future regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the effect on the Corporation and its operations and financial condition. See "*Industry Conditions - Environmental Protection Requirements*".

Petroleum and Natural Gas Title

Although title reviews will be completed according to industry standards prior to acquiring oil and natural gas properties, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation which could result in a reduction of the revenue received by the Corporation from exploitation of the property.

The right to explore, exploit or develop petroleum and natural gas is held in the form of licences and leases. If the holder of a licence or lease fails to meet specific requirements, the licence or lease may expire or be terminated and, should this occur, there may be a material adverse effect on financial results or the business.

Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of reserves and future net revenue to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserves and future net revenue information set forth in this AIF represent estimates only. The reserves and estimated future net revenue from the Corporation's properties have been independently evaluated effective December 31, 2017 by InSite. Estimates of economically recoverable oil and natural gas reserves and natural gas liquids, and related future net cash flows, are based upon a number of variable factors and assumptions. These include commodity prices, production, future operating, transportation, development and facility as well as decommissioning costs, access to market, and potential changes to the Corporation's operations or to reserve measurement protocols arising from regulatory or fiscal changes. All of these estimates may vary from actual circumstances, with the result that estimates of recoverable oil and natural gas reserves attributable to any property are subject to revision. In future, the Corporation's actual production, revenues, royalties, transportation, operating expenditures, finding, development, facility and decommissioning costs associated with its reserves may vary from such estimates, and such variances may be material.

Production

Production of oil and natural gas reserves at an acceptable level of profitability may not be possible during periods of low commodity prices. The Corporation will attempt to mitigate this risk by focusing on higher netback opportunities and will act as operator where possible, thus allowing the Corporation to manage costs, timing, method and marketing of production. Production risk is also addressed by concentrating exploration and development efforts in regions where infrastructure is or will be Storm owned or readily accessible at an acceptable cost. In periods of low commodity prices, the Corporation will shut in production, either temporarily or permanently, if field operating netbacks are sub-economic.

Production is also dependent in part on access to third party facilities with the result that production may be reduced by outages, accidents, maintenance programs and similar interruptions outside of the Corporation's control.

Storm's contracted gas processing capacity at third party facilities was approximately 80% of total raw gas production in the fourth quarter of 2017 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut in if capacity is allocated to other parties. Storm is working to increase the amount of raw gas production subject to contract. In the absence of additional contractual capacity, production growth will be delivered under interruptible terms.

Marketing Risks

Markets for the sale of future production of crude oil and natural gas are outside the Corporation's capacity to control or influence and can be affected by events such as weather, climate change, regulation, regional, national and international supply and demand imbalances, facility and pipeline access, geopolitical events, currency fluctuation, introduction of new or termination of existing supply arrangements, as well as downtime due to maintenance or damage, either to owned or third party facilities and pipelines. The Corporation will attempt to mitigate these risks as follows:

- Properties are developed in areas where there is access to processing and pipeline or other transportation infrastructure, and, where possible, owned by the Corporation.
- The Corporation will delay drilling or tie-in of new wells or shut in production if acceptable pricing cannot be realized.
- The Corporation constantly assesses the various markets into which production can be sold and if possible will direct production to markets offering the most attractive returns.
- The Corporation endeavours to secure access to facilities and pipelines under contracts setting volumes, prices and term.

Storm has contracted pipeline transportation capacity for approximately 76 Mmcf per day of natural gas sales volumes in the first quarter of 2018 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut in during partial outages or if capacity is allocated to other parties.

The Corporation's product profile comprises a large and growing percentage of natural gas. Pricing and access to markets has been affected by the growth of domestic gas production in the United States and could be affected by the establishment of LNG liquefaction facilities on Canada's west coast.

The marketability of oil and natural gas acquired or discovered is affected by numerous factors beyond the control of the Corporation. These factors include reservoir characteristics, market fluctuations, the proximity, capacity and access to oil and natural gas pipelines and processing facilities as well as government regulation.

Acquisition Risks

The Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may result in the Corporation's debt exceeding acceptable levels. Depending on future exploration and development plans, the Corporation may require financing additional to existing resources which may not be available or, if available, may not be available on favourable terms.

Trade Relations

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the 2016 presidential campaign in the United States a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. The administration has announced withdrawal of the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which among other things, significantly reduces corporate tax rates in the United States. This may affect competitiveness of other jurisdictions, including Canada. NAFTA is currently under renegotiation and the result is uncertain at this time. The administration has also taken action with respect to reduction of regulation which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the new administration in the United States will implement, and if implemented, how these actions may affect Canada and in particular the oil and gas industry. Any actions taken by the United States administration, including policies intended to reduce regulation and taxation in the United States or restrict immigration and access into the United States for citizens of certain countries, may have a negative effect on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including Storm.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taking steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on Storm's ability to market products internationally, increase costs for goods and services required for operations, reduce access to skilled labour and negatively affect business, operations, financial conditions and the market value of the Common Shares.

A change in federal, provincial or municipal governments in Canada may have an effect on the directions taken by such governments on matters that may affect the oil and gas industry, including the balance between economic development and environmental policy. One such example of this is the potential effect of the recent change of government in British Columbia and announcements and actions by the government of British Columbia that may affect the completion of the Trans-Mountain Pipeline project and other infrastructure projects.

Geo-Political 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 effect 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.

The remoteness of the Corporation's producing properties, gathering systems and facilities makes them vulnerable to damage or blockade by groups seeking to disrupt the Corporation's operations or industry activity generally.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Dependence on Key Personnel

The Corporation's success depends in large measure on certain key personnel including Brian Lavergne, Michael J. Hearn, Robert S. Tiberio, Emily Wignes, Jamie P. Conboy, H. Darren Evans and Bret A. Kimpton. The loss of the services of such key personnel could have an adverse effect on the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation are likely to be of central importance. Further, there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Readers must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Dilution

The Corporation may make future acquisitions or enter into financing or other transactions involving the issuance of securities which may be dilutive.

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of Western Canada. The Corporation is not aware that any specific claims have been made in respect of its properties and assets; however, if a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Third Party Credit Risk

The Corporation is or may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, counterparties to financial instruments and other parties. In the event such entities fail to meet their contractual obligations, such failures could have a material adverse effect on the Corporation, its funds flow and its liquidity structure.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on natural gas and NGL production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and renewable energy generation devices could reduce the demand for crude oil and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. Storm cannot predict the effect of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and funds flow .

Hydraulic Fracturing

Negative public perception of hydraulic fracturing may place pressure on governments in the jurisdictions where Storm operates to implement additional regulatory requirements or limitations on the utilization of hydraulic fracturing, which in turn could restrict Storm's operations and increase its costs.

The Corporation's development program at Umbach involves horizontal drilling and hydraulic fracturing which involves the injection of water, sand and small volumes of chemical additives under pressure into sub-surface geological formations to produce natural gas and oil. New laws, regulations or permitting requirements regarding hydraulic fracturing, source water and fluid disposal could result in operational delays and increased costs or could prevent the development of current reserves and resources. Source water for hydraulic fracturing and safe disposal of fluids recovered after hydraulic fracturing is subject to federal and provincial government regulations.

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the effect of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase Storm's costs of compliance.

Reputational Risk Associated with Operations

Any environmental damage, loss of life, injury or damage to property caused by Storm's operations could damage its reputation in the areas in which the Corporation operates. Negative sentiment towards Storm could result in a lack of willingness of municipal authorities to grant the necessary licenses or permits for the Corporation to operate its business and in residents in the areas where Storm is doing business opposing the Corporation's further operations in the area. If Storm develops a reputation of having an unsafe work site it may affect the Corporation's ability to attract and retain the necessary skilled employees and consultants to operate its business. Further, Storm's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which Storm has no control. In addition, environmental damage, loss of life, injury or damage to property caused by Storm's operations could result in negative investor sentiment towards the Corporation, which may result in limiting Storm's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Forward-Looking Statements May Prove Inaccurate

Readers are cautioned not to place undue reliance on forward-looking information in this AIF. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. See "*Notes Regarding Forward-Looking Statements*".

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than InSite, the independent reserve evaluators, and Ernst & Young LLP, the Corporation's auditors.

None of the principals of InSite had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or its associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

Ernst & Young LLP is independent of the Corporation in accordance with the Chartered Professional Accountants of Alberta Rules of Professional Conduct.

Certain legal matters relating to the business of the Corporation will be passed upon on the Corporation's behalf by McCarthy Tétrault LLP and Burnet, Duckworth & Palmer LLP. As at the date hereof, the partners and associates of each of these firms as a group beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are Ernst & Young LLP, Chartered Professional Accountants, 2200, 215 - 2nd Street S.W., Calgary, Alberta, T2P 1M4.

The transfer agent and registrar for the Common Shares of the Corporation is Alliance Trust Company at its office in Calgary, Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in the Corporation's information circular for the most recent annual meeting of shareholders that involved the election of directors.

Additional financial information is provided in the Corporation's audited consolidated financial statements, and Management's Discussion and Analysis for the year ended December 31, 2017. Management and auditors' reports on the financial statements are dated March 1, 2018 and Management's Discussion and Analysis is dated March 1, 2018. These documents are available on the SEDAR website at www.sedar.com and on the Corporation's website at www.stormresourcesltd.com.

APPENDIX A
FORM 51-101F2 - REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.[1]

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Storm Resources Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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 (the "**COGE Handbook**") as amended from time to time 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 by us for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management.

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
InSite Petroleum Consultants Ltd.	Evaluation of the P&NG Reserves of the Company as of December 31, 2017 and dated February 23, 2018	Canada	-	$1,007,958	-	$1,007,958
Totals			-	$1,007,958	-	$1,007,958

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

[1] For the convenience of readers, CSA Staff Notice 51-324 Glossary to NI 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") sets out the meanings of terms that are printed in italics in sections 1 and 2 of this Form or in NI 51-101, Form 51-101F1, Form 51-101F3 or Companion Policy 51-101CP.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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:

InSite Petroleum Consultants Ltd.
Calgary, Alberta, Canada

(signed) "D.L. Paddock"
D. L. Paddock, P.Eng.
Managing Director

March 29, 2018

APPENDIX B
FORM 51-101F3 - REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Storm Resources Ltd. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

InSite Petroleum Consultants Ltd., independent qualified reserves evaluators, has evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

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

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

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors of the Company has reviewed the Company'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 of the Company has, on the recommendation of the Reserves Committee, approved:

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

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

(c) the content and filing of this report.

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

(signed) "Brian Lavergne"
Brian Lavergne
President and Chief Executive Officer

(signed) "Michael J. Hearn"
Michael J. Hearn
Chief Financial Officer

(signed) "Matthew J. Brister"
Matthew J. Brister
Director

(signed) "P. Grant Wierzba"
P. Grant Wierzba
Director and Chairman of the Reserves Committee

March 29, 2018

APPENDIX C
AUDIT COMMITTEE TERMS OF REFERENCE

I. The Board of Directors' Mandate for the Audit Committee

1. **The Board of Directors** (the "**Board**") has responsibility for the stewardship of Storm Resources Ltd. (the "**Company**"). To discharge that responsibility, the Board is obligated by the *Business Corporations Act* (Alberta) to supervise the management of the business and affairs of the Company. The Board's supervisory function involves Board oversight or monitoring of all significant aspects of the management of the Company's business and affairs.

   Public financial reporting and disclosure by the Company are fundamental to the Company's business affairs and to its status as a publicly listed enterprise. The objective of the Board's monitoring of the Company's financial reporting and disclosure is to gain reasonable assurance of the following:

   (a) that the Company complies with all applicable laws, regulations, rules, policies and other requirement of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;

   (b) that the accounting principles, significant judgments and disclosures which underlie or are incorporated in the Company's financial statements are appropriate in the prevailing circumstances;

   (c) that the Company's quarterly and annual financial statements are accurate within a reasonable level of materiality and present fairly the Company's financial position and performance in accordance with generally accepted accounting principles; and

   (d) that appropriate information concerning the financial position and performance of the Company is disseminated to the public in a timely manner in accordance with corporate and securities law and with stock exchange regulations.

   The Board is of the view that monitoring of the Company's financial reporting and disclosure policies and procedures cannot be reliably met unless the following activities (the "**Fundamental Activities**") are, in all material respects, conducted effectively:

   (i) the Company's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Company's financial transactions;

   (ii) the internal financial controls are regularly assessed for effectiveness and efficiency;

   (iii) the Company's quarterly and annual financial statements are properly prepared by management of the Company ("**Management**") to comply with International Financial Reporting Standards ("**IFRS**"); and

   (iv) the Company's quarterly and annual financial statements are reported on by an external auditor appointed by the shareholders of the Company.

   To assist the Board in its monitoring of the Company's financial reporting and disclosure and to conform to applicable corporate and securities law, the Board has established the Audit Committee (the "**Committee**") of the Board.

2. Composition of Committee

(a) The Committee shall be appointed annually by the Board and consist of at least three members from among the directors of the Company, each of whom shall be an independent director (as determined under applicable laws). Officers of the Company, who are also directors, may not serve as members of the Audit Committee;

(b) The Board shall designate the Chairman of the Committee; and

(c) In the event of a vacancy arising in the Committee or a loss of independence of any member, the Committee will fill the vacancy within six months or by the following annual shareholders' meeting if sooner.

3. Reliance on Experts

In contributing to the Committee's discharging of its duties under this mandate, each member of the Committee shall be entitled to rely in good faith upon:

(a) financial statements of the Company represented to him by an officer of the Company or in a written report of the external auditor to present fairly the financial position of the Company in accordance with IFRS; and

(b) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

4. Limitations on Committee's Duties

In contributing to the Committee's discharging of its duties under Terms of Reference, each member of the Company shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in these Terms of Reference is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to endeavour to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the objectives of the Company's financial reporting are being met and to enable the Committee to report thereon to the Board.

II. Audit Committee Terms of Reference

The Audit Committee's Terms of Reference outlines how the Committee will satisfy the requirements set forth by the Board in its mandate. Terms of Reference reflect the following:

- Operating Principles;
- Operating Procedures; and
- Specific Responsibilities and Duties.

A *Operating Principles*

The Committee shall fulfill its responsibilities within the context of the following principles:

1) **Committee Values**

The Committee expects the Management of the Company to operate in compliance with corporate policies; reflecting laws and regulations governing the Company; and to maintain strong financial reporting and control processes.

2) **Communications**

The Committee and members of the Committee expect to have direct, open and frank communications throughout the year with Management, other Committee Chairmen, the external auditor, and other key Committee advisors or Company staff members as applicable.

3) **Financial Literacy**

All Committee Members should be sufficiently versed in financial matters to read and understand the Company's financial statements and also to understand the Company's accounting practices and policies and the major judgements involved in preparing the financial statements.

4) **Annual Audit Committee Work Plan**

The Committee, in consultation with Management and the external auditor, shall develop an annual Committee work plan responsive to the Committee's responsibilities as set out in these Terms of Reference. In addition, the Committee, in consultation with Management and the external auditor, shall participate in a process for review of important financial topics that have the potential to affect the Company's financial disclosure.

The work plan will be focused primarily on the annual and interim financial statements of the Company; however, the Committee may at its sole discretion, or the discretion of the Board, review such other matters as may be necessary to satisfy the Committee's Terms of Reference.

5) **Committee Expectations and Information Needs**

The Committee shall communicate its expectations to Management and the external auditor with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from Management and the external auditor at a reasonable time in advance of meeting dates.

6) **External Resources**

To assist the Committee in discharging its responsibilities, the Committee may at its discretion, in addition to the external auditor, at the expense of the Company, retain one or more persons having special expertise, including independent counsel.

7) **In Camera Meetings**

At the discretion of the Committee, the members of the Committee shall meet in private session with the external auditor, with Management, and with the Committee members only.

8) **Reporting to the Board**

The Committee, through its Chairman, shall report after each Committee meeting to the Board at the Board's next regular meeting.

9) **The External Auditor**

The Committee expects that, in discharging their responsibilities to the shareholders, the external auditor shall report directly to and be accountable to the Board through the Committee. The external auditor shall report all material issues or potentially material issues, either specific to the Company or to the financial reporting environment in general, to the Committee.

B ***Operating Procedures***

1) The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chairman, upon the request of two (2) members of the Committee or at the request of the external auditor.

2) A quorum shall be a majority of the members.

3) Unless the Committee otherwise specifies, the Secretary (or his or her deputy) of the Company shall act as Secretary of all meetings of the Committee.

4) In the absence of the Chairman of the Committee, the members shall appoint an acting Chairman.

5) A copy of the minutes of each meeting of the Committee shall be provided to each member of the Committee and to each director of the Company in a timely fashion.

C ***Specific Responsibilities and Duties***

To fulfill its responsibilities and duties, the Committee shall:

Financial Reporting

1) Review, prior to public release, the Company's annual and quarterly financial statements with Management and the external auditor with a view to gaining reasonable assurance that the statements *(i)* are accurate within reasonable levels of materiality, *(ii)* complete, *(iii)* represent fairly the Company's financial position and performance in accordance with IFRS. The Committee shall report thereon to the Board before such financial statements are approved by the Board;

2) Receive from the external auditor reports or their review of the annual and quarterly financial statements;

3) Receive from Management a copy of the representation letter provided to the external auditor and receive from Management any additional representations required by the Committee;

4) Review, prior to public release, and, if appropriate, recommend approval to the Board, of news releases and reports to shareholders issued by the Company with respect to the Company's annual and quarterly financial statements;

5) Review and, if appropriate, recommend approval to the Board of prospectuses, material change disclosures of a financial nature, management discussion and analysis, annual information forms and similar disclosure documents to be issued by the Company; and

6) Review and validate procedures for the receipt, retention and resolution of complaints received by the Company from any party regarding accounting, auditing or internal controls. For greater certainty, the Committee's responsibilities in this area will not include complaints about minor operational issues. (Examples of minor operational issues include late payment of invoices, minor disputes over accounts owing or receivable, revenue and expense allocations and other similar items characteristic of the normal daily operations of the accounting department of an oil and gas company.)

Accounting Policies

1) Review with Management and the external auditor the appropriateness of the Company's accounting policies, disclosures, reserves, key estimates and judgements, including changes or variations thereto;

2) Obtain reasonable assurance that they are in compliance with IFRS from Management and external auditor and report thereon to the Board;

3) Review with Management and the external auditor the apparent degree of conservatism of the Company's underlying accounting policies, key estimates and judgements and provisions along with quality of financial reporting; and

4) Participate, if requested, in the resolution of disagreements, between Management and the external auditor.

Risk and Uncertainty

1) Acknowledging that it is the responsibility of the Board, in consultation with Management, to identify the principal business risks facing the Company, determine the Company's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:

   (a) reviewing with Management the Company's tolerance for financial risks;

   (b) reviewing with Management its assessment of the significant financial risks facing the Company;

   (c) reviewing with Management the Company's policies and any proposed changes thereto for managing those significant financial risks; and

   (d) reviewing with Management its plans, processes and programs to manage and control such risks.

2) Review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

3) Where relevant, review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;

4) Review the adequacy of insurance coverage maintained by the Company; and

5) Review regularly with Management, the external auditor and the Company's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Company and the manner in which these matters have been disclosed in the financial statements.

Financial Controls and Control Deviations

1) Review the plans of the external auditor to gain reasonable assurance that the evaluation and testing of applicable internal financial controls is comprehensive, coordinated and cost-effective;

2) Receive regular reports from Management and the external auditor on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto;

3) Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Board, under conditions of confidentiality, concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgment, through existing reporting structures in the Company; and

4) Review, and periodically assess the adequacy of controls over financial information disclosed to the public, which is extracted or derived from the Company's financial statements.

Compliance with Laws and Regulations

1) Review regular reports from Management and others (e.g. external auditor) with respect to the Company's compliance with laws and regulations having a material effect on the financial statements including:

   (a) tax and financial reporting laws and regulations;

   (b) legal withholding requirements; and

   (c) other laws and regulations which expose directors to liability.

2) Review the filing status of the Company's tax returns and those of its subsidiaries.

Relationship with External Auditor

1) Recommend to the Board the nomination of the external auditor;

2) Approve the remuneration and the terms of engagement of the external auditor as set forth in the Engagement Letter;

3) Review the performance of the external auditor annually or more frequently as required;

4) Receive annually from the external auditor an acknowledgement in writing that the shareholders, as represented by the Board and the Committee, are their primary client;

5) Receive a report annually from the external auditor with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non-audit services by the Company;

6) Review with the external auditor the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditor proposes to employ;

7) Meet with the external auditor in the absence of Management to determine, *inter alia*, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditor or the reporting of their findings to the Committee;

8) Establish effective communication processes with Management and the Company's external auditor to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditor, Management and the Committee; and

9) Establish a reporting relationship between the external auditor and the Committee such that the external auditor can bring directly to the Committee matters that, in the judgment of the external auditor, merits the Committee's attention. In particular, the external auditor will advise the Committee as to disagreements between Management and the external auditor regarding financial reporting and how such disagreements were resolved.

Other Responsibilities

1) Approve annually the reasonableness of the expenses of the Chairman of the Board and the Chief Executive Officer;

2) After consultation with the Chief Financial Officer and the external auditor, consider at least annually, the quality and sufficiency of the Company’s accounting and financial personnel and other resources;

3) Approve in advance non-audit services, including tax advisory and tax compliance services, provided by the external auditor. However, the Committee can establish a threshold amount for fees for non-audit services to be provided by the external auditor without advance approval of the Committee. The nature of such services and the associated cost will be provided to the Committee at the next following meeting;

4) Investigate any matters that, in the Committee’s discretion, fall within the Committee’s duties;

5) Perform such other functions as may from time to time be assigned to the Committee by the Board;

6) Review and update the Terms of Reference on a regular basis for approval by the Board; and

7) The Committee will review disclosures regarding the organization and duties of the Audit Committee to be included in any public document, including quarterly and annual reports to shareholders, information circulars and annual information forms.