STORM RESOURCES LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2019

March 30, 2020

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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 Shares**" means common shares in the capital of Storm;

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

"**Credit Facility**" means the $205,000,000 extendible revolving bank facility of the Corporation, as amended from time to time, based on the Corporation's producing reserves;

"**GAAP**" means Generally Accepted Accounting Principles;

"**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 20, 2020 and effective December 31, 2019;

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

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

"**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, 2019 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	AECO is a virtual price point for all natural gas traded along the NOVA system under the provisions of the NOVA Inventory Transfer Service; the 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
CER	Canadian Energy Regulator
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 GAAP. Specifically, “netbacks”, “field operating netbacks”, “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 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, 2019 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Of the 92.6 drilling locations identified herein, 87.4 net are proved locations and 5.2 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 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° API gravity.

(m) "**medium crude oil**" means crude oil with a relative density greater than 22.3° 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**" mean 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 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 2020 and 2021, 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 commodity prices and costs of and supply and demand for crude oil, NGL and natural gas prices in each market in which production is sold;
- future gains or losses from risk management contracts;
- future production volumes in 2020 and 2021, 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 production costs (including royalties) and revenues and production costs per commodity unit;
- future capital expenditures and their allocation to specific activities or periods and number of wells to be drilled as part of the 2020 capital program;
- future growth plans through 2020 and 2021 including timing for the start-up of the Fireweed field compression facility;
- 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 GAAP and non-GAAP 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; 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:

- the global public health crises in respect of the outbreak of the novel coronavirus ("**COVID-19**"), including volatility and disruptions in the supply and demand for natural gas and NGL, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people;
- obtaining regulatory, third party and stakeholder approvals that are outside of Storm's control for the Corporation's operations, projects, initiatives and exploration and development activities and the satisfaction of any conditions to approvals;
- 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 (including climate change) and the cost of compliance with current and future environmental laws, including climate change laws along with risks relating to increased activism and public opposition to fossil fuels;
- 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;
- the risk that competing business objectives may exceed Storm's capacity to adapt and implement change;
- credit facility risks;
- the potential for security breaches of Storm's information technology and infrastructure by malicious persons or entities, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches;
- 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;
- increased competition from other industry participants for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- increased competition from companies that provide alternative sources of energy;
- 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, a major safety or environmental incident, or unexpected events such as fires (including forest fires); 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. Readers are cautioned that the foregoing list of factors is not exhaustive. 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 30, 2020, the Corporation has one subsidiary, SGR, which is wholly-owned and was incorporated under the ABCA.

The Corporation's registered office is located at 4300, 888 3rd Street S.W., Calgary, Alberta, T2P 5C5, and its head and principal office is located at 600, 215 – 2nd Street S.W., Calgary, Alberta, T2P 1M4.

GENERAL DEVELOPMENT OF THE BUSINESS

Year-Ended 2017

On January 1, 2017, Storm's natural gas processing arrangement with Spectra (NorthRiver Midstream) 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 natural gas leading to a step change in natural gas production levels.

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.

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 were completed wells.

Year-Ended 2018

During 2018, Storm twinned the third field compression facility at Umbach at a total cost of approximately $7 million, expanding Storm's compression capacity to 150 Mmcf per day which supports growth in corporate production to approximately 27,000 Boe per day. In the second quarter of 2018, the Corporation's Credit Facility was increased to $180 million from $165 million.

On July 11, 2018, the Corporation appointed Sheila A. Leggett to the Board of Directors.

In August 2018, Storm finalized a two-year growth plan that was expected to increase production to approximately 30,000 Boe per day by the end of 2020 (21% liquids) through the construction of a 50 Mmcf per day sour gas plant to develop the Nig land block and the construction of a 50 Mmcf per day field compression facility to develop the Fireweed land block.

In 2018, Storm drilled four wells (100% working interest) and completed 11 (10.5 net) wells. Storm had an inventory of seven Montney horizontal wells (6.5 net) that had not started producing at the end of 2018, four (3.5 net) of which were completed.

Year-Ended 2019

Fiscal 2019 was defined by third party outages (total of 43 days), a material decline in the contracted NGL price, and lower condensate and natural gas prices which resulted in funds flow declining from the previous year. During 2019, Storm commenced construction of the sour gas plant at Nig with the project completed and started up February 22, 2020.

In response to the decline in funds flow, capital investment was reduced to $97 million from initial guidance of $128 million. Approximately 63% of capital investment was directed to the Nig gas plant project.

In the second quarter, Storm's Credit Facility was increased from $180 million to $205 million, with approximately $132 million drawn on the facility at year end (including letters of credit in the amount of $10 million).

In 2019, Storm drilled six wells (100% working interest) and completed five (5.0 net) wells. Storm had an inventory of five Montney horizontal wells (4.5 net) that had not started producing at the end of 2019, one (0.5 net) of which was completed.

The InSite Report assigned gross proved plus probable reserves as at December 31, 2019 in the amount of 195,482 Mboe, a year-over-year increase of 7%. Storm's undeveloped lands totaled 211,112 net acres at the end of 2019. 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 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, Nig, Fireweed 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 business plan with a disciplined approach to capital investment, based on funding the Corporation's capital investment from funds flow, debt (limited to 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 debt to funds flow targets to complete an acquisition, or a seasonally oriented drilling program or a major addition to facilities. Hedging is used 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 and fixing of price differentials between sales points. 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 maintaining a low cost structure, in each of capital expenditures, operating costs and overhead costs. A low cost structure means that the Corporation can maintain acceptable margins and 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 67% of Storm's revenue in 2019 was generated from the sale of natural gas, with the remaining 33% 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. During 2018, crude oil and condensate pricing gradually improved through the first ten months of the year before collapsing in November over concerns of supply outpacing demand. In 2019, crude oil pricing decreased compared to 2018 as a result of a lower oil demand forecast due to trade tensions between the U.S. and China which continued to affect the global economy and fears of an oversupplied market, despite rising tensions in the Middle East. In 2020, COVID-19 and possible supply increases from Saudi Arabia and Russia have dramatically decreased the price of crude oil.

Since 2013, the Corporation has primarily focused on exploiting high condensate and NGL content natural gas properties in the Umbach, Nig and Fireweed areas of northeast British Columbia.

Specialized Skill and Knowledge

Exploration for and the acquisition, development and production of oil, natural gas and NGL reserves requires specialized skills and knowledge in the areas of petroleum engineering, geophysics, geology, facility construction, health, safety and environmental matters and surface land and mineral title management. 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 2020.

Environmental Considerations

Storm constantly monitors and actively manages its approach to environmental concerns. Storm has procedures in place to ensure that significant care is taken in the day-to-day management of its oil and gas properties. The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. Storm maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. Storm has established operational and emergency response procedures and safety and environmental programs to reduce potential loss exposure. No assurance can be given that the application of environmental laws to the business and operations of Storm will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Storm's financial condition, results of operations or prospects. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors – Environmental Risks*" in this AIF.

Health, Safety and Environmental Policies

Storm is committed to meeting or exceeding industry standards in each jurisdiction in which it operates with respect to human rights, environment, health and safety policies. Management, employees and contractors are governed by and required to comply with Storm's environment, health and safety policy as well as all applicable federal, provincial and municipal legislation and regulations. Storm has established roles and responsibilities to facilitate effective management of its environment, health and safety policy throughout the organization. It is the primary responsibility of the managers, supervisors and other senior field staff of Storm to oversee safe work practices and ensure that rules, regulations, policies and procedures are being followed. Storm maintains and will continue to maintain a safe and environmentally responsible work place, and will continue to provide training, equipment and procedures to all individuals in adhering to our policies. Storm will also solicit and take into consideration input from our neighbours, communities and other stakeholders in regard to protecting people and the environment.

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 2020.

Employees

As of December 31, 2019, the Corporation had 27 full-time employees, 8 part-time employees and 1 consultant.

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	-

Name and Municipality of Residence	Position Held	Date First Elected or Appointed as Director[(5)]
Robert S. Tiberio Calgary, Alberta	Chief Operating Officer	-
Jamie P. Conboy Calgary, Alberta	Vice President, Geology	-
H. Darren Evans Calgary, Alberta	Vice President, Exploitation	-
Bret A. Kimpton Calgary, Alberta	Vice President, Production	-
Emily Wignes Calgary, Alberta	Vice President, Finance	-
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
Sheila A. Leggett[(3)(4)] Calgary, Alberta	Director	July 11, 2018
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 15,142,160 Common Shares representing approximately 12.5% of the issued and outstanding Common Shares.

Each of Lavergne, Hearn, Tiberio, Conboy, Evans, Kimpton and Wignes, 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 30, 2020 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 16 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.

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 commencing on 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.

Matthew J. Brister, Director

Mr. Brister is an independent businessman and was Chairman of the Board of Chinook Energy Inc. ("Chinook") from December 2013 until June 2017. Mr. Brister holds a Bachelor of Science in Geology from the University of Calgary.

John A. Brussa, Director

Mr. Brussa has been an energy lawyer, specializing in the area of taxation, since 1982. He is currently a Partner and the Chairman of Burnet, Duckworth & Palmer LLP, a full service Calgary based law firm. Over the same period Mr. Brussa has gained wide experience in corporate governance. Over the last 30 years, he has served on a number of Boards of Directors of public corporations across diverse industries as well as the governing bodies of several charitable foundations and not-for-profit corporations. He is a past member of the Board of Governors of the Canadian Tax Foundation, a Jarislowsky Fellow in Business at the University of Calgary's Haskayne School of Business and a cabinet member of the Resolve Campaign to end homelessness in Calgary. In addition to his professional duties, Mr. Brussa currently serves as a mentor at the Centre for Advanced Leadership in Business.

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 an independent businessman with relevant past experience as Chief Financial Officer of publicly listed oil and gas companies. Mr. Clark 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.

Sheila A. Leggett, Director

Ms. Leggett is Chair of Board for International Standards Organization (ISO) Technical Committee 207 Environmental Management, and Chair of Board for TELUS Spark. Ms. Leggett holds a Bachelor of Science in Biology from McGill University, a Masters of Science in Biology from University of Calgary and ICD.D director certification from the Institute of Corporate Directors.

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. Mr. Turnbull holds a Bachelor of Arts degree (magna cum laude) from Queen's University and a Bachelor of Laws degree from the University of Toronto. He is past Chair of the Calgary Zoological Society and presently sits on the Board of the Calgary Health Trust.

P. Grant Wierzba, Director

Mr. Wierzba is an independent businessman and was a director of Chinook from November 2004 until August 2019. 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 executive financial advisory services company, since July 2017 and from February 2013 until September 2015. Since November 2019 he has been a director of Centaurus Energy Inc. Mr. Wilson was the Chief Financial Officer and Corporate Secretary of Aspenleaf Energy Limited from September 2015 until June 2017 and from June to November of 2015 was a director of Marquee Energy Ltd. 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 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 provided legal services to Storm for the year ended December 31, 2019. 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 2019, or in respect of which any of its properties are subject, or was the subject matter of in 2019, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2019, 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 year 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, 2019 ($)	Fees Paid to Auditor in Year Ended December 31, 2018 ($)
Audit Fees(1)	140,000	118,000
Audit-Related Fees(2)	33,000	32,000
Tax Fees(3)	2,900	7,700
All Other Fees(4)	19,890	-
Total	195,790	157,700

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit of Storm's consolidated financial statements.
(2) "Audit-Related Fees" include quarterly reviews.
(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 general 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, 2019 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 the full corporate decommissioning liability for all wells and facilities. 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	210,418	8,253	43,322	188,650	6,730	38,172
Developed Non-Producing	4,076	91	771	3,593	70	669
Undeveloped	536,365	22,630	112,025	487,052	19,097	100,272
Total Proved	750,859	30,974	156,118	679,295	25,897	139,113
Probable	186,573	8,270	39,365	163,235	6,674	33,880
Total Proved plus Probable	937,432	39,244	195,483	842,529	32,572	172,993

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	612,052	485,065	399,523	340,434	297,875	10.47
Developed Non-Producing	5,204	3,350	2,247	1,547	1,079	3.36
Undeveloped	1,476,538	937,831	628,601	436,660	310,307	6.27
Total Proved	2,093,794	1,426,246	1,030,371	778,641	609,261	7.41
Probable	825,098	425,209	248,771	159,563	109,366	7.34
Total Proved plus Probable	2,918,892	1,851,455	1,279,142	938,204	718,627	7.39

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	578,137	466,464	388,827	334,031	293,907
Developed Non-Producing	3,845	2,524	1,724	1,206	851
Undeveloped	1,093,533	682,789	447,549	301,897	206,551
Total Proved	1,675,515	1,151,776	838,010	637,134	501,309
Probable	611,458	314,275	183,243	117,062	79,880
Total Proved plus Probable	2,286,973	1,466,052	1,021,253	754,195	581,189

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	4,339,663	500,498	1,041,681	642,469	61,223	2,093,794	418,279	1,675,515
Total Proved plus Probable	5,702,544	692,468	1,349,132	675,087	66,966	2,918,892	631,919	2,286,973

The full corporate decommissioning liability for all existing wells and facilities was included in the evaluation and totaled $38.3 million on an undiscounted basis. The total proved and total proved plus probable abandonment and reclamation costs also includes the decommissioning liability for all future drilling locations and associated infrastructure.

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%) ($M)	Unit Value Using Net Reserves ($/Mcf)
Proved	Conventional Natural Gas	1,030,371	1.23
Proved plus Probable	Conventional Natural Gas	1,279,142	1.23

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, 2019 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 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)
2020	2.50	2.05	61.00	73.26	40.29	27.84	0%	0.76
2021	2.75	2.32	64.50	76.77	46.06	31.47	2%	0.77
2022	3.00	2.60	66.50	78.76	51.19	33.08	2%	0.78
2023	3.15	2.69	68.20	80.00	52.00	34.40	2%	0.80
2024	3.25	2.81	69.90	82.38	53.54	35.63	2%	0.80
2025	3.35	2.94	71.50	84.38	54.84	36.70	2%	0.80
2026	3.42	3.00	73.50	86.88	56.47	37.79	2%	0.80
2027	3.49	3.06	74.97	88.61	57.60	38.77	2%	0.80
2028	3.56	3.12	76.47	90.38	58.75	39.77	2%	0.80
2029	3.63	3.18	78.00	92.19	59.93	40.56	2%	0.80
2030	3.70	3.24	79.56	94.04	61.12	41.38	2%	0.80
Thereafter +2% per annum								

	2019 Actual Price and Forecast InSite Future Prices Storm Wellhead Gas Price (Cdn$/Mcf)	2019 Actual Price and Forecast InSite Future Prices Storm Wellhead NGL Price (Cdn$/Bbl)
2019 Actual(1)	2.17	39.28
2020(2)	1.93	53.77
2021(2)	2.32	57.28
2022(2)	2.63	59.76
2023(2)	2.77	61.28
2024(2)	2.92	63.23

Notes:

(1) 2019 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, 2018	731,365	158,126	889,492	28,011	6,110	34,121
Discoveries	-	-	-	-	-	-
Extensions & Improved Recoveries	55,352	38,084	93,436	3,357	2,305	5,662
Technical Revisions	360	(9,685)	(9,324)	979	(146)	834
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(348)	47	(302)	-	-	-
Production	(35,870)	-	(35,870)	(1,373)	-	(1,373)
December 31, 2019	750,859	186,573	937,432	30,974	8,270	39,244

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	231,400.1	736,803.5	7,379.5	22,725.0
December 31, 2017	67,328.2	314,872.4	2,287.9	10,699.8
December 31, 2018	201,054.8	517,370.5	9,040.2	19,861.1
December 31, 2019	49,765.3	533,619.4	2,985.9	21,586.0

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	60,871.2	223,251.7	1,951.2	5,728.3
December 31, 2017	-	69,344.8	-	2,362.1
December 31, 2018	10,728.0	17,164.8	356.1	569.7
December 31, 2019	24,818.0	41,800.8	1,489.1	2,135.0

Proved and probable undeveloped reserves are determined by InSite adhering to the practices outlined within the COGE handbook with uncertainty applied at the individual location level to account for the potential variability in well results. There are 87.4 net total proved undeveloped locations assigned to be developed over the next 4 years which account for 112,000 Mboe of proved reserves. In addition, there are 5.2 net future development locations assigned probable reserves which account for 9,000 Mboe of probable reserves. The Corporation's total proved plus probable undeveloped locations are assigned to be developed over a 4-year period. The additional probable reserves assigned to the proved locations account for 20,000 Mboe. Total proved plus probable undeveloped reserves totalling 141,000 Mboe are all scheduled to produce within capacity of existing facilities or facilities to which capital has been assigned within the reserves evaluation. The time required to expand facilities and gathering infrastructure extends the scheduling of proved and probable undeveloped reserves beyond a 2-year time frame. All of the Corporation's future drilling locations are in the Nig and Umbach areas of northeast British Columbia.

It is possible that it could take longer to develop the reserves identified in the InSite report. 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 wells exceeding or not meeting forecast production levels); (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 and Nig, there are 87.4 net future horizontal drilling locations included in the proved category and 92.6 net locations included in the proved plus probable category.

Year	**Forecast Prices and Costs**	
	Proved	Proved Plus Probable
	($M)	($M)
2020	85,600	85,600
2021	169,575	169,575
2022	268,735	289,044
2023	118,558	130,868
2024	-	-
Total Undiscounted	642,468	675,087
Total Discounted at 10%	521,619	546,292

($million)	2019	2018	2017
FDC – proved reserves	642	686	412
FDC – proved plus probable reserves	675	707	481

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, 2019 InSite future price forecast.

In 2020, Storm plans to drill 6 - 10 gross horizontal wells (4.0 - 8.5 net) and complete 8 - 10 horizontal wells (6.5 - 8.5 net) with 5 - 10 gross horizontal wells estimated to start production (5.0 - 8.5 net) during the year in the Umbach, Nig and Fireweed areas of northeast British Columbia.

The Corporation expects to fund its total 2020 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, Nig and Fireweed, Northeast British Columbia

Storm's land holdings as at December 31, 2019 in the Montney formation total 121,000 net acres, or 172 net sections. Production in 2019 averaged 20,182 Boe per day (81% natural gas, 11% condensate and 8% NGL). Storm's $96.8 million gross capital investment in 2019 was invested primarily in constructing the Nig Gas Plant, as well as drilling and completion activities on a four well pad at Nig. In total, six horizontal wells were drilled during the year (100% working interest) and five horizontal wells (5.0 net) were completed.

Storm had an inventory of five horizontal wells (4.5 net) that had not started producing at the end of 2019, one (0.5 net) of which was completed.

At December 31, 2019 Storm operated three 100% working interest field compression facilities that have total capacity of 150 Mmcf per day which supports growth in corporate production to approximately 27,000 Boe per day.

Grande Prairie Area, Northwest Alberta

Production in 2019 averaged approximately 43 Boe per day. In 2015, Storm completed the disposition of properties in the Grande Prairie area with production prior to sale of approximately 500 Boe per day. The Corporation owns one remaining property in the Grande Prairie area. No capital was invested on this property by the Corporation in 2017, 2018, or 2019 and no activity is planned for 2020.

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, 2019, Storm has a 100% working interest in 108 sections in the HRB (72,500 net acres) which is prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Storm's one horizontal well was shut in for the majority of 2019 due to low natural gas prices. Cumulative production to date from this well is approximately 6 Bcf raw. A core area totaling 30 sections (100% working interest) has been proven to be productive based on the aforementioned 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 78 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, 2019 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	-	-	75.0	71.4	-	-	37.0	31.7
Alberta	-	-	-	-	2.0	1.2	12.0	9.1
Total	-	-	75.0	71.4	2.0	1.2	49.0	40.8

In addition to the wells noted in the above table, Storm has 27 (19.5 net) wells that have been abandoned as at December 31, 2019 that are in various stages of the reclamation process.

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, 2019 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, 2019.

	Gross Acres(1)	**Net Acres(2)**	**Net Acres Expiring Within One Year(3)**
Umbach Montney and other - BC	135,510	98,974	9,165
Horn River Basin - BC	73,200	71,613	25,573
Grande Prairie - AB	11,120	6,477	-
Other areas	41,403	34,048	673
Total	261,232	211,112	35,410

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.
(3) Subject to continuation applications and/or payments to extend the term.
(4) Numbers in this table may not add due to rounding.

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 cost or work commitments on lands with no attributed reserves except for annual lease rental payments.

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 up to 50% of most recent quarterly or monthly production for the next 18 months and up to 25% for the following 19 to 36 months. Anticipated production growth is not hedged. Due to the variable liquidity of hedge markets at various delivery points, and the requirement to hedge only the target percentage delivered to a specific market, hedge target volumes are not always achievable at acceptable prices.

Details of risk management contracts in respect of Storm's hedging activities can be found in Note 16, "*Financial Instruments*", to Storm's audited consolidated financial statements for the year ended December 31, 2019 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, 2019, the Corporation had resource pools and operating losses of approximately $503 million available for deduction against future taxable income. These existing pools, plus pool additions through the Corporation's capital program in 2020 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 2019. 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, 2019.

	Capital Investment ($M)			
	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Costs ($M)	-	-	1,086	95,757

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, 2019.

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Natural gas wells	5.0	5.0	-	-	5.0	5.0
Oil wells	-	-	-	-	-	-
Service wells	1.0	1.0	-	-	1.0	1.0
Stratigraphic test wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	6.0	6.0	-	-	6.0	6.0

During 2020, the Corporation will focus on further development in the Umbach, Nig and Fireweed areas of northeast British Columbia. Subject to the availability of capital, Storm intends to drill 6 - 10 gross horizontal wells (4.0 - 8.5 net), complete 8 - 10 gross horizontal wells (6.5 - 8.5 net), and anticipates 5 - 10 gross wells (5.0 - 8.5 net) will start production during the year.

Production Estimates

Gross – Production by Product

The following tables disclose for each product type the total volume of production estimated by InSite for 2020 based on the Corporation's reserves and ownership at December 31, 2019.

2020	Conventional Natural Gas (Mmcf)	Natural Gas Liquids (Mbbls)	Boe/d
Proved			
Umbach	28,940	1,092	16,161
Nig	15,002	861	9,184
HRB	-	-	-
Grande Prairie	-	-	-
Total Proved	43,942	1,953	25,345
Proved Plus Probable			
Umbach	29,255	1,104	16,338
Nig	15,195	875	9,309
HRB	-	-	-
Grande Prairie	-	-	-
Total Proved Plus Probable	44,450	1,979	25,647

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.

	2019 Quarter Ended			
	Q4 Dec. 31	**Q3** Sept. 30	**Q2** June 30	**Q1** March 31
Average Daily Production[(1)]				
Conventional Natural Gas (Mcf/d)	108,679	91,053	97,510	96,537
Condensate (Bbls/d)	2,416	1,856	2,081	2,199
NGL (Bbls/d)	1,846	1,564	1,591	1,534
Combined (Boe/d)	22,375	18,596	19,923	19,823
Average Price Received[(1)(3)]				
Conventional Natural Gas ($/Mcf)	3.28	2.42	2.64	4.49
Condensate ($/Bbl)	66.56	63.45	71.12	62.77
NGL ($/Bbl)	6.11	2.29	4.87	31.43
Combined ($/Boe)	23.64	18.36	20.72	31.26
Royalties Paid				
Conventional Natural Gas ($/Mcf)	(0.13)	0.19	0.13	(0.29)
Condensate ($/Bbl)	(8.44)	(7.12)	(8.55)	(7.81)
NGL ($/Bbl)	(0.79)	(0.11)	(0.70)	(4.41)
Combined ($/Boe)	(1.59)	0.19	(0.32)	(2.61)
Operating & Transportation Expenses				
Conventional Natural Gas ($/Mcf)	(2.14)	(2.30)	(2.30)	(2.31)
Condensate ($/Bbl)	(4.62)	(4.47)	(5.42)	(5.08)
NGL ($/Bbl)	-	-	(0.24)	-
Combined ($/Boe)	(10.87)	(11.71)	(11.85)	(11.81)
Netback Received[(2)(3)]				
Conventional Natural Gas ($/Mcf)	1.01	0.31	0.47	1.89
Condensate ($/Bbl)	53.50	51.86	57.15	49.88
NGL ($/Bbl)	5.32	2.18	3.91	27.02
Combined ($/Boe)	11.18	6.84	8.55	16.84

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, 2019:

	Conventional Natural Gas (Mcf/d)	**Condensate** (Bbls/d)	**Natural Gas Liquids** (Bbls/d)
Umbach[(1)]	97,754	2,137	1,634
HRB	447	-	-
Grande Prairie	257	1	-
Total	98,458	2,138	1,634

Note:

(1) Includes Nig.

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 30, 2020, 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 for the period January 1, 2019 to December 31, 2019.

Month	High ($)	Low ($)	Volume
January 2019	2.05	1.69	2,422,575
February 2019	2.36	1.51	4,023,730
March 2019	2.46	2.18	1,937,744
April 2019	2.56	2.03	1,276,222
May 2019	2.09	1.68	665,670
June 2019	2.10	1.63	2,988,100
July 2019	1.79	1.49	837,594
August 2019	1.75	1.14	1,674,376
September 2019	1.58	1.19	7,523,351
October 2019	1.48	1.16	1,298,684
November 2019	1.47	1.19	3,835,131
December 2019	1.68	1.37	11,878,578

Note:

(1) Data obtained from the TMX website.

PRIOR SALES

The following table summarizes the issuance of securities convertible into Common Shares during the year ended December 31, 2019.

Date of Issuance	Description of Transaction	Number and Type of Securities	Price per Security
March 6, 2019	Grant of Options	30,000 Options	$2.27
March 25, 2019	Grant of Options	60,000 Options	$2.34
April 4, 2019	Grant of Options	19,200 Options	$2.35
June 1, 2019	Grant of Options	28,800 Options	$1.83
July 16, 2019	Grant of Options	50,000 Options	$1.65
July 23, 2019	Grant of Options	50,000 Options	$1.70
December 3, 2019	Grant of Options	30,000 Options	$1.36
December 10, 2019	Grant of Options	2,748,700 Options	$1.48

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulation governing its operations (including land tenure, exploration, development, production, emissions, safety, 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 operating in the same jurisdictions. 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 Canadian Energy Regulator Act (the "**CER Act**") and the National Energy Board Act Part VI (Oil and Gas) Regulation (the "**Part VI Regulation**"). The Part VI Regulation will remain in effect until 2022, unless earlier replaced under the CER Act. The CER Act and the Part VI Regulation authorize crude oil, natural gas and NGL exports under either short-term orders or long-term licences. 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. To obtain a crude oil export licence, a mandatory public hearing with the Canada Energy Regulator (the "**CER**") is required, which is no longer the case for natural gas and NGL. For natural gas and NGL, the CER uses a written process that includes a public comment period for affected persons. Following the comment period, the CER completes its assessment of the application and, subject to any terms or conditions imposed, either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes will not exceed Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CER Act and all associated regulations and orders made pursuant to the CER Act. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CER Act safely and efficiently, as well as the purpose of the CER Act, to effect "oil and natural gas exploration and exploitation... in a manner that is safe and secure and that protects people, property and the environment" and "to regulate trade in energy products." All crude oil, natural gas and NGL licences require the approval of the cabinet of the Canadian federal government. 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 CER 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.

As discussed in more detail below, 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 receive regulatory approvals and for construction of major projects to be completed. In addition, the transportation capacity deficit may be further exacerbated should Canada's production of crude oil, natural gas and NGL continue to increase.

Furthermore, the emergence of new sources of supply as natural gas deposits formerly regarded as inaccessible or uneconomic, particularly those locked in shales and other tight formations, both in Canada and the U.S., are now being exploited using new drilling and fracturing techniques. From 2009 onwards, increased supply of natural gas from these sources along with continuing improvement in well productivity, has resulted in 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 continue to have a considerable influence on natural gas pricing, at least in the short and medium term.

Several LNG export projects from Canada have been proposed but have a long lead time before they are expected to be operational. If consummated, these projects would open another path for exporting natural gas and may result in Canada becoming a significant exporter of LNG which could lead to future internationalization of pricing for natural gas.

Transportation Constraints, Pipeline Capacity and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Pipeline capacity and transportation availability is highly variable across different areas and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new or expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years. Current pipeline construction projects before various regulatory bodies, if approved, would be expected to improve pricing.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the CER and the cabinet of the federal government. On August 28, 2019, Bill C-69 and related legislation came into force, creating a new regulatory regime pursuant to the CER Act; the *Canadian Navigable Waters Act*; and the *Impact Assessment Act*. The CER Act replaces the NEB with the CER. The CER has similar oversight over federal energy infrastructure projects as the NEB had. However, approvals for projects requiring impact assessment will now be conducted by a review panel established under the *Impact Assessment Act* instead of the CER. Its process for implementing this oversight are intended to be more inclusive of the Canadian public and Indigenous peoples and are to consider a broader range of impacts beyond environmental effects. Under the CER Act, if the review panel established under the *Impact Assessment Act* recommends that a project not be approved, the cabinet of the Canadian federal government may only reject the application or ask that a project not be approved, the cabinet of the Canadian federal government may only reject the application or ask that the recommendation be reconsidered. As this regulatory regime is new, it is uncertain how it will play out in practice; the CER has not yet undertaken a major project approval and it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Even when projects are approved at a federal level, such projects can face further delays from court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of the relevant environmental review processes, which creates further uncertainty. The lack of regulatory certainty will likely have an influence on investment decisions for major projects. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGL, including pipelines, rail, trucks and marine transport. Improved access to other markets could help to alleviate the oversupply situation in Western Canada and improve commodity prices. Several proposals have been announced to increase oil pipeline capacity out of Western Canada to reach Eastern Canada, the U.S. and international markets by export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects.

Natural gas prices in Alberta and British Columbia have also declined in recent years generally due to increased supply in all regions of North America. Since mid-2017, companies that have not been able to secure firm access to transport their natural gas production out of Western Canada have been forced to accept spot pricing in Western Canada for their natural gas which has generally been depressed in comparison to other regions (at times producers have received negative pricing for their natural gas production). Further contributing to low prices in Western Canada has been required repairs or upgrades to existing pipeline systems which have led to further capacity reductions and apportionment of firm access, which has further depressed prices by periodically limiting injection of natural gas into storage. Pricing in Western Canada has improved since the Fall of 2019 which may indicate a shift in the supply-demand imbalance (supply has declined while demand has increased). In addition, future demand may benefit from the first LNG export facility planned for the west coast of Canada whose proponents announced a positive final investment decision in October 2018 and are proceeding with the project.

The Canada-United States-Mexico Agreement and Other Trade Agreements

The Canada-United States-Mexico Agreement ("**CUSMA**") among the governments of Canada, the United States and Mexico became effective on March 13, 2020, following ratification by the legislative bodies of the three signatory countries. CUSMA replaced the North American Free Trade Agreement ("**NAFTA**"), which had been effective since January 1, 1994.

The proportionality rule (Article 605) of NAFTA prevented Canada from implementing policies that limited exports to the U.S. and Mexico relative to the total supply produced in Canada. In the context of energy resources, Canada was free to determine whether exports of energy resources to the United States or Mexico would be allowed, provided that any export restrictions did 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 were prohibited from imposing minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also required energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes caused minimal disruption to contractual arrangements and avoided undue interference with pricing, marketing and distribution arrangements.

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, the adoption of CUSMA could have an effect on Western Canada's crude oil and natural gas industry, including the Corporation's business. CUSMA does not impose a proportionality rule like Article 605 of NAFTA. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia and Europe, CUSMA may allow for greater export diversification than existed under NAFTA.

Canada and ten other countries have agreed on the text of 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 CPTPP is in force among the first seven countries to ratify the agreement, including Canada, Australia, Japan, Mexico, New Zealand, Vietnam and Singapore.

Canada has also pursued a number of other international free trade agreements with countries around the world. Canada and the European Union agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

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 $90,000,000 in total liability.

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 generally ranging from two to ten years, and on conditions set forth in provincial legislation including requirements to perform specific work or make additional payments. The provincial governments in Western Canada conduct regular land sales where crude oil and natural gas companies bid for leases or licences to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions have been satisfied. To develop crude oil and natural gas resources, it is necessary to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage. Some oil and natural gas rights can also be privately owned and the right to explore for and produce such oil and natural gas is granted by leases on such terms and conditions as may be negotiated with the owner.

Each of the provinces of Alberta and British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights to deeper geological formations that are below productive interval(s) and have not been proven to be productive 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 shallower geological formations that are above productive interval(s) and have not been proven to be productive for all leases and licenses.

An additional category of mineral rights ownership includes the federal government’s ownership of some legacy mineral lands and within indigenous reservations designated under the *Indian Act* (Canada). The federal government agency, Indian Oil and Gas Canada (“**IOGC**”), is responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. Such responsibilities include managing subsurface and surface leases, in consultation with the applicable indigenous peoples, as well as collecting royalty revenues on behalf of the indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the “**IOGA**”) and the *Indian Oil and Gas Regulations, 1995* (the “**1995 Regulations**”). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act,* amending and modernizing the IOGA (the “**Modernized IOGA**”), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying regulations (the “**2019 Regulations**”). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards.

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. 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.

In addition, the Government of Canada may from time to time provide incentives to the oil and gas industry. In November 2018, the federal government announced its plans to implement an accelerated investment incentive that will provide oil and gas businesses with eligible Canadian development expenses ("**CDE**") and Canadian oil and gas property expenses ("**COGPE**") a first year deduction that is 150% of the 30% or 10% deduction, respectively, that would normally be available for CDE or COGPE expenses incurred before 2024 and 125% for expenses incurred between 2023 and before 2028. The Canadian government also announced in late 2018 that it will make $1.6 billion available to the oil and gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada, which have lent or guaranteed approximately $629 million to date.

British Columbia

Producers 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 oil, natural gas, NGL and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the price 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%. For crude oil, royalties take into account the production of crude oil on a well-by-well basis and can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract, the vintage of the well, the density of the produced oil, and when the crude oil pool was discovered. Generally, royalty rates for all products are reduced on low-productivity wells and other wells with applicable royalty exemptions which reflects 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, the Alberta Government adopted a modernized 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.

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.

In July 2019, the Government of Alberta enacted the *Royalty Guarantee Act* (Alberta) which provides certainty that the royalty structure in place when a well is drilled remains in place for at least ten years.

Regulatory Authorities and Environmental Regulation

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. 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, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On August 28, 2019, the Government of Canada enacted new legislation to overhaul the existing environmental assessment process and replace the NEB with the CER. Pursuant to the legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. Additional categories of projects are included within new impact assessment process, such as offshore wind energy projects; however, exemptions have been added for oil sands projects located in provinces that have achieved requisite greenhouse gas emissions targets. The revamped approval process for applicable major developments has 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 impacts and 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 impacts; 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 are now 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. The effects of the new legislation remain unclear as the old NEB regulations are still in force until such new regulations come into force.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* ("**OTMA**") 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. The OTMA came into force on June 21, 2019 and 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, may negatively affect the ability of producers to access global markets.

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 (the "**OGC**") 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 OGC 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.

The Government of British Columbia recently passed *Bill 51 – 2018: Environmental Assessment Act*, which replaced the environmental assessment regime that was in place since 2002. The amended legislation came into force on December 16, 2019. Under the amended legislation, proposed projects will be subject to an enhanced environmental review process, similar to the federal environmental assessment process, and enhanced indigenous engagement in the project approval process with an emphasis on consensus-building, in alignment with British Columbia's recent passage of *Bill 41 – 2019: Declaration on the Rights of Indigenous Peoples Act*, which affirmed and adopted the United Nations Declaration on the Rights of Indigenous Peoples.

Simultaneously with the enactment of the *Environmental Assessment Act*, the British Columbia Government enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project. However, many details of the new assessment process remain unknown, but the British Columbia Government has released a proposed timetable for the release of supplementary and informational materials through 2020.

In 2018, the British Columbia Government proposed amendments to the British Columbia *Environmental Management Act* that would see new heavy oil imports, whether by rail, expanded pipeline, or otherwise, managed through a discretionary permitting process (the "**Proposed Amendments**"). The Proposed Amendments would directly affect the transport of heavy oil blends across British Columbia to tidewater through the Trans Mountain Pipeline. In its unanimous decision, the *Reference Re Environmental Management Act* (British Columbia) delivered May 24, 2019; the British Columbia Court of Appeal held that the Proposed Amendments are unconstitutional. The Supreme Court of Canada heard British Columbia's appeal on January 16, 2020, and found that constitutionally, the British Columbia Government does not have the jurisdictions to make the Proposed Amendments. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. On January 29, 2020, the Government of British Columbia acknowledged that Canada's highest court has ruled in support of the Trans Mountain Pipeline expansion proceeding, and indicated that the Government of British Columbia would not initiate further challenges against the Trans Mountain Pipeline.

On July 12, 2018, the OGC announced interim measures for oil and gas developments in Blueberry River First Nation ("**BRFN**") traditional territory (the "**Interim Measures**"). The Interim Measures were part of the Regional Strategic Environmental Assessment Interim Measures Agreement that was entered into by the BRFN, the OGC, the Ministry of Energy, Mines and Petroleum Resources and the Ministry of Forests, Lands, Natural Resource Operations and Rural Development, which came into force on July 16, 2018. The Interim Measures addressed concerns raised by BRFN with respect to new oil and gas development activities by managing development activities in certain areas while prohibiting or restricting new surface disturbance in more sensitive areas. The Interim Measures applied to three identified areas in BRFN territory, located in the Peace Region of northeastern British Columbia. On July 3, 2019, the OGC released Industry Bulletin 2019-13, effectively cancelling the Interim Measures, and providing that the Commission will follow the Interim Consultation Procedure with Treaty 8 First Nations to guide consultation with BRFN going forward.

Alberta

The AER is the single regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related Acts including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act* and the Environmental Protection and Enhancement Act. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

Liability Management Rating Programs

British Columbia

The OGC oversees a Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the OGC determines the required security deposits for permit holders under the OGAA. The ratio of a permit holder's deemed assets to deemed liabilities is referred to as its liability management rating ("**LMR**"). Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

As of April 1, 2019 a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. The OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders must pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The OGAA permits the OGC to impose more than one levy in a given calendar year.

The liability levy will be phased in over three years. The 2019/20 fiscal year will see 50% of orphan funding come from the new liability levy, increasing by 25% in each subsequent year. The remaining funding in these years will come from the OGC's operating production levy. By 2021/22, the liability levy will provide 100% of the annual levy required to fund restoration treatment of orphan sites.

Effective May 31, 2019, the *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") established the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring 100% of current dormant sites are abandoned by 2031 and reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the OGC, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the annual work plan.

Alberta

The AER administers the Licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). At its core, the AER uses the AB LMR Program to aid in determining the ability of licensees to manage the abandonment and reclamation obligations associated with the licensee's assets. If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licenses. This ratio of a licensee's assets to liabilities across the three programs is also referred to as the LMR. Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect the Corporation's ability to obtain or transfer licenses.

Complementing the AB LMR Program, the AER established an orphan well association (the "**Orphan Association**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and AB OWL Program if a licensee or working interest participant ("**WIP**") becomes defunct. Licensees in the AB LLR Program and AB OWL Program fund the Orphan Association through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Association 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.

In *Redwater Energy Corporation (Re)* ("**Redwater**"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the provincial OGCA, including the AB LLR Program and the federal *Bankruptcy and Insolvency Act* (the "**BIA**"). This ruling meant that receivers and trustees of insolvent entities had the right to renounce assets within insolvency proceedings and was affirmed by a majority of the Alberta Court of Appeal. On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability while dealing with the company's valuable assets for the benefit of the company's creditors without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management programs. The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LLR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further changes to the rules at any time. The Supreme Court of Canada's decision in Redwater alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is currently in the process of reviewing the framework.

The AER has also implemented the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP 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.

Climate Change Regulation

Climate change regulation, namely regulating industrial GHG emissions, at both the federal and provincial level has the potential to significantly impact the oil and natural gas industry in Canada. Storm is committed to fully complying with existing regulations and to sustainable resource development in Canada.

As part of its ongoing business planning, Storm estimates futures costs associated with CO_2 emissions in its operations and in the evaluation of future projects based on the expected carbon price under current and pending GHG regulations which is a current price of $40/tonne of CO_2 in British Columbia increasing to approximately $50/tonne of CO_2 in 2021.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of March 12, 2020, 189 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about prospective carbon market and emissions cuts until the next climate conference to be held in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provides for a carbon pricing strategy; however, each province has the flexibility to enact their own regulations for pricing carbon emissions as long as they meet the federal benchmark in terms of reducing GHG emissions. The implementation of the Framework's strategy began on June 21, 2018, when the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: a regulatory system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under this legislation price will escalate by $10 per year until it reaches $50/tonne in 2022, at which time it will be subject to review. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions. This system applies in provinces and territories that request it and in those that do not have a carbon-pricing system in place that meets the federal benchmark.

Currently six provinces and territories have carbon-pricing systems in place that meet federal requirements (British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador and the

Northwest Territories). The federal carbon-pricing regime took effect in Saskatchewan, Manitoba, Ontario and New Brunswick in April 2019; it took effect in the Yukon and Nunavut in July 2019; and the federal fuel charge under the GGPPA took effect in Alberta on January 1, 2020. Saskatchewan and Ontario have challenged the constitutionality of the federal government's pricing regime through constitutional references to their respective Courts of Appeal; New Brunswick has intervened in Saskatchewan's constitutional challenge. The Saskatchewan and Ontario references have advanced in parallel where the appeal Courts ruled in favour of the constitutionality of the federal carbon tax. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada and such court is set to hear the appeals in March 2020. On February 24, 2020, the Alberta Court of Appeal determined the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals or, relatedly, whether those scheduled hearings will be delayed as a result. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled appeals, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

On April 26, 2018, the Government of Canada passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations came into force on January 1, 2020 and seek to reduce emissions of methane from the crude oil and natural gas sector. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane which will require crude oil and natural gas operations to use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. 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 October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators so as to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

British Columbia

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

British Columbia was also the first Canadian province to implement a carbon tax in 2008. In 2012, the carbon tax reached \$30/tonne and was subsequently raised to \$35/tonne in April 2018 and to \$40/tonne in April 2019. The Government of British Columbia intends to continue raising its carbon tax in \$5 increments until it reaches a carbon price of \$50/tonne in 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.

In December 2018, the Government of British Columbia announced an updated clean energy plan, CleanBC, which seeks to ensure that British Columbia reduces GHG emissions by 40% by 2030 (based on 2007 levels). The CleanBC plan includes a number of initiatives targeting the industrial, transportation, construction, and waste sectors of the British Columbia economy that are expected to achieve 75% of the reduction by 2030 with further initiatives to achieve the remainder of the reduction being communicated over the next 18 to 24 months. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030;

(iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of crude oil and natural gas production; (v) reducing 45% of methane emissions associated with upstream oil and natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles. The 2019 provincial budget provided $902 million over three years to support CleanBC, including electric vehicle rebates, incentives for making homes and businesses more energy efficient, and an enhanced climate action tax credit.

On January 16, 2019, the OGC announced a series of amendments to the *Drilling and Production Regulation* and has introduced new regulations to reduce methane emissions from upstream oil and gas operations to meet or exceed federal and provincial methane emission reduction targets. The amendments to the *Drilling and Production Regulation* came into effect on January 1, 2020. Developed with input from environmental groups and industry, the new regulations address the primary sources of methane emissions from British Columbia's upstream oil and gas industry, which are pneumatic devices, equipment leaks, compressor seals, glycol dehydrators, storage tanks and surface casing vents. The changes include enhancements to requirements for leak detection and repair, designed to ensure leaks are detected and repaired quickly. Additionally, robust data management and reporting requirements to ensure transparent reporting of industry actions are under development.

In addition, regulations under the GGIRCA require that fugitive emissions surveys be conducted up to three times per year and industrial facilities that emit 10,000 tonnes or more of carbon dioxide equivalent (CO_2e) per year are required to report their emissions.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The *Climate Leadership Act* came into force on January 1, 2017 and established a fuel charge that was initially higher and subsequently kept pace with the federal carbon price. 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 emissions attributable to upgraders, the electric energy portion of cogeneration, and other prescribed emissions.

The *Carbon Competitiveness Incentives Regulation* (the "**CCIR**"), which replaced the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposed an output-based benchmark on competitors in the same emitting industry. This applied to facilities emitting more than 100,000 tonnes of GHGs per year and mandates quarterly and annual reporting requirements. Facilities would pay a carbon price based on the amount by which emissions exceeded a performance benchmark and would receive credits if emissions were below the benchmark. In 2018 and 2019, the carbon price was $30.00 per tonne CO_2e.

On December 4, 2019, the Government of Alberta approved its proposed Bill 19 to replace the CCIR with the Technology Innovation and Emissions Reduction ("**TIER**"). Under TIER, thresholds for large facilities and compliance mechanisms remain largely the same as under the CCIR. However, under TIER, a facility will be measured against its own average emissions from 2013 to 2015 and its target will be set at ten percent below that level for 2020. If a facility is over its target, the price will be $30.00 per tonne CO_2e. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, and as an alternative to the federal carbon tax, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO_2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

Beginning on May 30, 2019 as part of the provincial *Carbon Tax Repeal Act*, the provincial carbon levy no longer applies to any type of fuel; however, as Alberta then had no carbon levy equivalent for fuel consumption, the federal government announced that on January 1, 2020 the federal fuel charge will apply in Alberta.

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 financial results are largely 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 low commodity prices and volatility may also affect the Corporation's ability to meet guidance targets and 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 as the economics of producing from some wells may become impaired.

In addition, bank borrowings available to the Corporation are, in part, determined by the value of the Corporation's assets. A sustained material decline in commodity prices from historical average prices could reduce the value of the Corporation's assets, 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.

Market conditions which include global oil and natural gas supply and demand and recent events including actions taken by OPEC, Russia's recent withdrawal from OPEC, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between China and Iran, isolationist and punitive trade policies, shale production in the United States, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, curtailment of production of crude oil by the Government of Alberta, the outbreak of COVID-19 and possible supply increases from Saudi Arabia and Russia have caused significant volatility in commodity prices. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks, including attacks on oil infrastructure in oil producing nations, in the United States or other countries could adversely affect the economies of Canada, the United States and other countries. These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the future of the oil and natural gas industry. In addition, the difficulties encountered by midstream proponents in Western Canada to obtain the necessary approvals on a timely basis to build pipelines, LNG plants and other facilities to provide better access to markets for the oil and natural gas industry has led to additional downward pressure on oil and natural gas prices which has further reduced confidence in the oil and natural gas industry in Western Canada.

Global Health Crises

The Corporation's business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China; on January 30, 2020, the World Health Organization ("**WHO**") declared the outbreak a global health emergency; and on March 11, 2020 the WHO declared the outbreak of COVID-19 a global pandemic. In China, reactions to the spread of COVID-19 have led to, among other things, significant restrictions on travel within China, temporary business closures, quarantines and a general reduction in consumer activity. The outbreak has spread throughout Canada, the United States, Europe and the Middle East with cases of COVID-19 increasing around the world. The spread of COVID-19 has led companies and various jurisdictions to impose restrictions such as quarantines, business closures and domestic and international travel restrictions. The duration of the business disruptions internationally and related financial impact cannot be reasonably estimated at this time. Similarly, the Corporation cannot estimate whether or to what extent this pandemic and the potential financial impact may extend to countries outside of those currently impacted.

Such public health crises can result in volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, crude oil prices have significantly weakened in response to the outbreak of COVID-19. The risks to the Corporation of such public health crises also include risks to employee health and safety and a slowdown or temporary suspension of operations in geographic locations impacted by an outbreak. This could include the Corporation's wells and facilities and/or third party facilities and pipelines used by the Corporation. At this point, the extent to which COVID-19 may impact the Corporation is uncertain; however, it is possible that COVID-19 may have a material adverse effect on the Corporation's business, results of operations and financial condition.

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 funds 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 May 29, 2020. There is a risk that the Credit Facility will not be renewed for the same amount or on the same terms or that it will not be increased. 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 has no covenants under the Credit Facility. If the Credit Facility is not extended at renewal time, the facility moves into a term phase whereby the outstanding loan amount is to be repaid one full year later. In the event the lenders reduce the borrowing base below the amount drawn, the Corporation would have 90 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders.

Interest Rates

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

Possible 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 funds flow is lower than expected or capital costs for 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. 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. 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. 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.

Acquisitions and Dispositions

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.

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 can create uncertainty surrounding the ability to accurately estimate future royalties and, correspondingly, funds flow, resulting in additional volatility and uncertainty for producers, including the Corporation.

Environmental Legislation

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.

The Corporation's oil and natural gas operations are 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. 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 or exceeding 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. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to Storm.

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. 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 – Regulatory Authorities and Environmental Regulation"* and "*Industry Conditions – Climate Change Regulation."*

Government Regulation

Field operations, including drilling, completions and construction of facilities and pipelines, 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.

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 sale of products including oil, natural gas and natural gas liquids. The Corporation also faces increased competition from companies that provide alternative sources of energy. 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 (including forest fires), 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. In addition, if the Corporation enters into hedging arrangements it may be exposed to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes which would require purchasing replacement volumes (possibly at a price higher than what was hedged) to fill the physical delivery commitment that corresponds to the hedge; prices are lower than the hedged price; there is a widening of price differentials between the delivery point for production and the delivery point assumed in the hedge arrangement; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; and/or there was a sudden unexpected material event that impacts crude oil and natural gas prices.

The Corporation may enter into agreements to fix the interest rate on a portion of its outstanding bank debt in order to offset the risk of higher interest charges if market rates increase; however, if market rates decrease, during the period of such agreements, the Corporation would not fully benefit from the lower market rates.

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 and Cost of Equipment and Services

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.

Operating and development costs are affected by a number of factors including price inflation, scheduling delays and access to skilled labour.

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 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 implications of the Supreme Court of Canada's decision regarding Redwater Energy Corporation on the AER's rules and policies and lending practices in the crude oil and natural gas sector will evolve as the decision is considered and applied by regulators, lenders and receivers/trustees. See "*Industry Conditions – Liability Management Rating Programs*".

Climate Change and Carbon Pricing

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which require the Corporation to comply with GHG emissions legislation at the provincial and federal level. Concerns over climate change, fossil fuel extraction, GHG emissions and water and land-use practices is leading to climate change policy that 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 changes to regional, provincial and/or federal climate change regulations to manage GHG emissions which could significantly increase operating and development costs.

The federal and British Columbia governments have implemented legislation to tax carbon emissions which may decrease the demand for oil and natural gas and could increase capital expenditures, production costs and abandonment and reclamation obligations. Future planned and unplanned increases to carbon taxes may have a material adverse effect on financial results.

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. Specifically, changes to these regulations could affect demand for the Corporation's products, or could increase capital expenditures, compliance costs, permitting delays, production costs and abandonment and reclamation obligations.

The imposition of carbon taxes and increasing environmental regulation puts the Corporation at a disadvantage to competitors who operate in jurisdictions where there is no carbon price and fewer regulations relating to GHG emissions.

Concerns about climate change have resulted in a number of environmental activists and members of the public lobbying for restrictions around the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the associated regulations, it is not possible to predict the effect on the Corporation and its operations and financial results. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation"* and "*Industry Conditions – Climate Change Regulation*".

Extreme Weather Conditions

In addition to climate policy risk, the industry faces physical risks attributable to a changing climate. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Corporation's ability to access the Corporation's properties, cause operational difficulties, including damage to machinery and facilities. Extreme weather may also increase the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets are located in locations that are proximate to forests and grasslands, and a wildfire may lead to significant downtime and/or damage to such assets. Moreover, extreme weather conditions may disrupt the Corporation's ability to transport produced natural gas and NGL as well as goods and services along the supply chain.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may make the ground unstable, limit access and, as a result, cause reduced operations or a cessation of operations. Forest fires are also an increasing risk that could damage Storm's infrastructure, limit access and, as a result, also lead to reduced operations or a cessation of operations.

Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict access to Storm's properties and cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas typically fluctuates during cold winter months and hot summer months.

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

Reserves are depleted by production. Developing or acquiring additional reserves is capital intensive. There is no assurance that additional reserves can be added to offset depletion which may affect the valuation of the Corporation.

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. 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 markets, and potential changes to operations or to reserve estimates arising from regulatory or fiscal changes. Actual revenues and production, royalty, transportation, finding and development, facility and decommissioning costs may vary from such estimates, and such variances may be material. Estimates of recoverable oil and natural gas reserves attributable to any property are subject to revision if actual results differ from estimates.

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 having a low cost structure which includes acting 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.

The Corporation has contracted for firm gas processing capacity at third party facilities; however, some production does rely on access to uncontracted interruptible capacity. There is a risk that some or all of the contracted and the uncontracted, interruptible portion could be reduced or shut in due to outages or if capacity is not available. Transportation of gas to processing facilities and to sales markets is similarly exposed to the extent that not all of the required capacity is covered by contracted firm capacity. In addition, contracts for both processing and transportation are for a fixed term and may not be renewed or may be renewed under more onerous terms.

Marketing

Markets for the sale of future production of crude oil, NGL 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.

The Corporation's product profile is largely comprised of natural gas. Pricing and access to markets has been affected by the growth of domestic gas production in North America.

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, composition of the crude oil and natural gas, market fluctuations, the proximity, capacity and access to oil and natural gas pipelines and processing facilities as well as government regulation.

The Corporation is subject to counterparty risks related to marketing arrangements. A failure by such counterparties to make payments may adversely affect financial results. The Corporation attempts to mitigate this risk by dealing with reputable counterparties.

Trade Relations

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 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.

Political and Geo-Political

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 but not limited to royalties, taxes, regulations, environmental policy and licensing of wells and facilities.

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of commodities acquired or discovered by the Corporation. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

Non-Governmental Organizations and Terrorism

The crude oil and natural gas industry may, at times, be subject to public opposition. Such public opposition could expose Storm to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Aboriginal groups, landowners, environmental interest groups (including those opposed to oil and gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences, and direct legal challenges, including the possibility of litigation relating to climate change, GHG emissions or environmental regulations. There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require significant and unanticipated capital and operating expenditures which may negatively impact the Corporation's business, financial condition, results of operations and prospects.

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. Investors 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 (including climate change) 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.

Indigenous Land Claims

Indigenous peoples have claimed title and rights or have opposed development in portions of Western Canada. 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.

The federal and provincial governments of Canada have a duty to consult and, where appropriate, accommodate indigenous peoples where their interests may be affected by a Crown action or decision. This may result in regulatory approvals being made subject to further conditions, delayed or not being obtained which could have a material effect on the Corporation's activities.

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's financial results and financial condition.

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 reduction regulations, 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 impact future activity and production levels and increase costs.

Hydraulic fracturing involves the injection of water, sand and small volumes of chemical additives under high pressure into sub-surface geological formations to produce natural gas and condensate. New laws, regulations or permitting requirements regarding hydraulic fracturing, monitoring for induced seismicity, 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.

Changing Investor Sentiment

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the impact of crude oil and gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and indigenous rights, have affected certain investors' sentiments towards investing in the crude oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in crude oil and natural gas properties or companies tied to crude oil and natural gas or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can be costly and require a significant time commitment from the Board, management and employees of the Corporation. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the crude oil and natural gas industry, and more specifically, the Corporation, may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares, even if the Corporation's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Corporation's assets which may result in an impairment change.

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 Stikeman Elliott 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, 2019. Management and auditors' reports on the financial statements and Management's Discussion and Analysis are dated February 27, 2020. 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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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, 2019, 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, 2019 and dated February 20, 2020	Canada	-	$1,279,142	-	$1,279,142
Totals			-	$1,279,142	-	$1,279,142

[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.

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

7. We have no responsibility to update our 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) "Radu Afilipoaei"
Radu Afilipoaei, P.Eng.
Managing Director

March 30, 2020

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"	*(signed) "Michael J. Hearn"*
Brian Lavergne President and Chief Executive Officer	Michael J. Hearn Chief Financial Officer
(signed) "Matthew J. Brister"	*(signed) "P. Grant Wierzba"*
Matthew J. Brister Director	P. Grant Wierzba Director and Chairman of the Reserves Committee

March 30, 2020

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.