STORM RESOURCES LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2013

March 31, 2014

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DEFINITIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this Annual Information Form. Certain other terms and abbreviations used herein, but not defined herein, are defined in NI 51 101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**ABCA**" means the *Business Corporations Act* (Alberta);

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

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

"**Bellamont**" means Bellamont Exploration Ltd.;

"**Bellamont Arrangement**" has the meaning ascribed under the heading "*General Development of the Business – Year Ended 2012*";

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

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time;

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

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

"**Credit Facility**" means the $65,000,000 extendible revolving bank facility of the Corporation, as amended from time to time, based on the Corporation's producing reserves;

"**Grande Prairie Dispositions**" has the meaning ascribed under the heading "*General Development of the Business – Year Ended 2013*";

"**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 InSite, in accordance with NI 51-101, dated February 24, 2014 and effective December 31, 2013;

"**May Financing**" means the $23,650,400 bought deal short form prospectus financing of Common Shares and concurrent $5,640,000 non-brokered private placement of Common Shares which closed on May 1, 2013;

"**Mica Acquisition**" has the meaning ascribed under the heading "*General Development of the Business – Year Ended 2011*";

"**Mica Disposition**" has the meaning ascribed under the heading "*General Development of the Business – Year Ended 2012*";

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

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

"**November Financing**" means the $30,150,000 bought deal short form prospectus financing of Common Shares and concurrent $3,685,000 non-brokered private placement of Common Shares which closed on November 19, 2013;

"**Private Placement**" has the meaning ascribed under the heading "*General Development of the Business – Year Ended 2012*";

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

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

"**SGR Arrangement**" has the meaning ascribed under the heading "*General Development of the Business – Year Ended 2012*";

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

"**Umbach Acquisition**" has the meaning ascribed under the heading "*General Development of the Business - Subsequent Events to Year Ended 2013*";

"**Umbach Financing**" means the $29,725,000 bought deal short form prospectus financing of Common Shares and concurrent $5,125,000 non-brokered private placement of Common Shares which closed on February 14, 2014; and

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

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. The information set out in this Annual Information Form is stated as at December 31, 2013 unless otherwise indicated.

SELECTED ABBREVIATIONS

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

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels of oil or natural gas liquids
Bbls/d	barrels per day
Mbbls	thousands of barrels
Mboe	thousands of barrels of oil equivalent
Mmbbls	millions of barrels
Mmboe	millions of barrels of oil equivalent
NGL	natural gas liquids
WTI	West Texas Intermediate

Natural Gas

Bcf	billions of cubic feet
Bcfe	billions of cubic feet equivalent
Btu	British Thermal Unit
GJ	gigajoule
Mcf	thousands of cubic feet
Mmcf	millions of cubic feet
Mcf/d	thousands of cubic feet per day
Mmcf/d	millions of cubic feet per day
Mmbtu	millions of British Thermal Units
Mmbtu/d	millions of British Thermal Units per day
Tcf	Trillions of cubic feet

3-D	three dimensional
AECO-C	leading Canadian benchmark price for natural gas
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 Bbl 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
BOPD	barrel of oil per day
CCS	carbon capture and storage
DPIIP	Discovered Petroleum Initially in Place - as set out in the COGE Handbook, the quantity of hydrocarbons that are estimated to be in place within a known accumulation. It is divided into recoverable and unrecoverable portions, with the estimated future recoverable portion classified as reserves and contingent resources. There is no certainty that it will be economically viable or technically feasible to produce any portion of DPIIP except for those portions identified as proved or probable reserves
GHG	greenhouse gas
kPa	one thousand pascals
NAV	net asset value
NPV	net present value
OGIP	Original Gas in Place
OPEC	Organization of Petroleum Exporting Countries
US$	United States dollar
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSION

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	6.289
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	1.0537
Psi	kPa	6.89

CURRENCY OF INFORMATION

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

NON-IFRS MEASURES

This Annual Information Form contains the term “netback” which is not defined by IFRS and therefore may not be comparable to performance measures presented by others. In this Annual Information Form, "netback" is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. Operating netback represents revenue and realized gain or loss on financial derivatives, less royalties, operating expenses and transportation expenses and has been presented on a per Boe basis. Management believes that in addition to net income, netbacks are a useful supplemental measure as it assists in the determination of the Corporation's operating performance. Readers should be cautioned, however, that this measure should not be construed as an alternative to both net income and net cash from (used in) operating activities, which are determined in accordance with IFRS, as indicators of the Corporation's performance.

Further, reference is made to funds from operations which does not have a standardized meaning as prescribed by generally accepted accounting principles (GAAP) codified by IFRS. Funds from operations may not be comparable to the calculation of similar amounts for other entities. Funds from operations is not intended to represent, or be equivalent to, cash from operating activities calculated in accordance with IFRS.

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

The determination of oil and 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.

(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:

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

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

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.

Additional Definitions

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

(a) "**associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

(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 natural gas liquids.

(c) "**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.

(d) "**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.

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

(iii) dry hole contributions and bottom hole contributions;

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

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

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

(g) "**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".

(h) "**future prices and costs**" means future prices and costs that are:

(i) generally accepted as being a reasonable outlook of the future;

(ii) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (i).

(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 the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using forecast prices and costs before general and administrative charges, interest and taxes.

(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) "**natural gas**" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Shale gas is equivalent to natural gas. Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

(m) "**natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

(n) "**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.

(o) "**non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

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

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

(r) "**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;

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

(iii) an agreement with a foreign government or authority under which the Corporation participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

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

(s) "**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.

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

(u) "**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.

(v) "**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.

(w) "**solution gas**" means natural gas dissolved in crude oil.

(x) "**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**".

(y) "**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.

(z) "**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

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

NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain information set forth in this Annual Information Form, including management's assessment of Storm's future plans and operations, 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", "outlook", "forecast" or other similar words and include statements relating to or associated with individual wells, facilities, regions or projects. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas liquids and natural gas prices;
- future production levels and production levels by commodity;
- future revenues and costs (including royalties) and revenues and costs per commodity unit;
- future capital expenditures and their allocation to specific exploration and development activities or periods;
- future drilling, completion and tie-in of wells;
- future facility access, acquisition or construction;
- future earnings or losses;
- future non-GAAP funds from operations and future cash flows;
- future availability of financing;
- future asset acquisitions or dispositions;
- intentions with respect to investments;
- future sources of funding for capital programs and future availability of such sources;
- future decommissioning costs and discount rates used to determine the net present value of such costs;
- development plans;
- estimates of value in use of property and equipment;
- future debt levels;
- availability of credit facilities;
- future tax liabilities and future use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells;
- future finding and development costs, operating costs, and general and administrative costs;
- treatment under governmental regulatory regimes and tax and royalty laws;
- future provisions for depletion and depreciation and accretion;
- expected share-based compensation charges;
- future interest rates and interest costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and geographical areas developed; and
- changes to any of the foregoing.

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

- oil and natural gas production levels;
- the success of the Corporation's operations and exploration and development activities;
- prevailing weather conditions, commodity prices and exchange rates;
- the availability of labour, services and drilling equipment;
- the availability of capital to fund planned expenditures;

- timing and amount of capital expenditures;
- general economic and financial market conditions;
- the success, nature and timing of enhanced recovery activities;
- the ability of the Corporation to secure necessary personnel, equipment and services;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- the success of exploration and development activities; and
- access to market for the Corporation's production.

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

- industry conditions including commodity prices;
- pipeline and facility constraints, capacity constraints and access to market;
- volatility of commodity prices;
- currency fluctuations;
- imprecision of reserve estimates and related costs including royalties, production costs and future development costs;
- environmental risks;
- stock market volatility;
- ability to access sufficient capital from internal and external sources and the ability of the Corporation to realize value from acquired assets and corporations;
- risks inherent in oil and natural gas operations;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- success of drilling programs;
- geological, technical, drilling, completion and processing problems;
- results of enhanced recovery responses;
- the outcome of litigation brought against the Corporation or other disputes involving the Corporation;
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "Risk Factors".

All of these caveats should be considered in the context of current economic conditions, in particular low prices for natural gas over the last several years, 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 of management of Storm.

Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied 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 Annual Information Form. 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 the completion of the Bellamont Arrangement to amalgamate with Bellamont.

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 under the symbol "SRX".

As of March 31, 2014, the Corporation has one subsidiary, SGR, which is wholly-owned and was incorporated under the ABCA.

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

GENERAL DEVELOPMENT OF THE BUSINESS

Year-Ended 2011

On December 1, 2011, Storm completed the acquisition of 150 Boe/d in the Mica area of northeast British Columbia for total consideration of $15.4 million (the "**Mica Acquisition**"). The effective date of the Mica Acquisition was September 1, 2011. The Mica Acquisition was financed from Storm's existing cash resources and an expanded credit facility. Production from the Mica Acquisition at the time of completion was comprised of approximately 70% light oil (38° API) and NGL and 30% natural gas.

Storm drilled four wells (2.2 net) in 2011 with a 100% success rate. These wells were comprised of one horizontal well (0.4 net) in the Muskwa/Otter Park formation of the HRB and three horizontal wells (1.8 net) in the Montney formation at Umbach.

Year-Ended 2012

On January 12, 2012, Storm completed the acquisition of SGR pursuant to a plan of arrangement involving Storm, 1644140 Alberta Ltd., SGR and the holders of common shares of SGR (the "**SGR Arrangement**"). Pursuant to the SGR Arrangement, Storm issued an aggregate of 11,761,190 Common Shares, at a deemed issuance price of $3.73 per Common Share, for the acquisition of all of the issued and outstanding common shares of SGR that were not previously held by Storm. The acquisition of SGR added approximately 360 Boe/d of production (100% natural gas) and 81,400 net acres of undeveloped land which includes 58,400 net acres in the HRB. Storm's undeveloped land holdings in the HRB following the SGR Arrangement totalled 88,600 net acres at a 100% working interest.

On March 23, 2012, Storm completed the acquisition of Bellamont pursuant to a plan of arrangement involving Storm, Bellamont and the holders of class A shares of Bellamont (the "**Bellamont Arrangement**").

Pursuant to the Bellamont Arrangement, Storm paid an aggregate of $20 million in cash and issued an aggregate of 16,740,096 Common Shares, at a deemed issuance price of $2.37 per Common Share, for the acquisition of all of the issued and outstanding class A shares of Bellamont. The cash component of the Bellamont Arrangement was financed by the concurrent completion of: (i) a brokered private placement of 2,353,000 Common Shares, at a price of $3.40 per Common Share; and (ii) a non-brokered private placement of 4,593,000 Common Shares, at a price of $3.40 per Common Share, for aggregate gross proceeds of approximately $23,616,000 (collectively, the "**Private Placement**"). Upon completion of the Bellamont Arrangement, Storm's production increased by approximately 2,000 Boe/d (49% liquids). In addition, Storm added light oil drilling inventory in the Grimshaw and Grande Prairie areas of northwest Alberta. Including the assumption of estimated net debt of $36.9 million, the total cost of the transaction was approximately $96.6 million.

Upon closing of the Bellamont Arrangement, the Corporation's banking facility was increased from $18 million to $70 million.

On October 18, 2012, Storm completed the disposition of 150 Boe/d of production in the Mica area of northeast British Columbia for net proceeds of $13.3 million (the "**Mica Disposition**"). The net proceeds of the Mica Disposition were applied to reduce Storm's bank debt. The effective date of the Mica Disposition was September 1, 2012. As a result, the Corporation's banking facility was reduced to $62 million.

Storm drilled six wells (4.4 net) in 2012 with a 100% success rate. These wells included four horizontal wells (2.4 net) and one vertical well (1.0 net) in the Montney formation at Umbach and one horizontal well (1.0 net) in the Dunvegan C light oil pool in the Grande Prairie area.

Year-Ended 2013

On January 18 and February 15, 2013, Storm completed the disposition of properties in the Grande Prairie area of northwest Alberta, with production totaling 300 Boe/d, for proceeds of $20 million (the "**Grande Prairie Dispositions**"). The net proceeds of the Grande Prairie Dispositions were applied to reduce Storm's bank debt. The effective date of the Grande Prairie Dispositions was January 1, 2013. This resulted in the Corporation's banking facility being further reduced to $52 million.

On May 1, 2013, Storm completed the May Financing, which consisted of: (i) a bought deal financing by way of short form prospectus pursuant to which, Storm, through a syndicate of underwriters, issued an aggregate of 12,580,000 Common Shares at a price of $1.88 per Common Share for aggregate gross proceeds of $23,650,400; and (ii) a non-brokered private placement financing of 3,000,000 Common Shares at a price of $1.88 per Common Share to certain investors, including insiders, identified by Storm for aggregate gross proceeds of $5,640,000.

On November 19, 2013, Storm completed the November Financing, which consisted of: (i) a bought deal financing by way of short form prospectus pursuant to which, Storm, through a syndicate of underwriters, issued an aggregate of 9,000,000 Common Shares at a price of $3.35 per Common Share for aggregate gross proceeds of $30,150,000; and (ii) a non-brokered private placement financing of 1,100,000 Common Shares at a price of $3.35 per Common Share to certain investors, including insiders, identified by Storm for aggregate gross proceeds of $3,685,000.

In the fourth quarter of 2013 the banking facility was increased to $65 million in recognition of production and reserve growth at Umbach.

The InSite Report assigned proved plus probable reserves as at December 31, 2013 in the amount of 40,541 Mboe. Storm's undeveloped lands totaled 194,012 net acres at that date. See "*Statement of Reserves Data and Other Oil and Gas Information*".

Subsequent Events to Year-Ended 2013

On January 31, 2014, Storm completed the acquisition of 100% working interest in 29 sections of land in the Umbach-Nig area prospective for liquids rich natural gas from the Montney formation, including two horizontal wells producing from the formation, (the "**Umbach Acquisition**") for aggregate consideration paid to the vendor of approximately $30,000,000 in cash and issued an aggregate of 13,629,442 Common Shares at a deemed issuance price of $4.25 per Common Share.

On February 14, 2014, Storm completed the Umbach Financing, which consisted of: (i) a bought deal financing by way of short form prospectus pursuant to which, Storm, through a syndicate of underwriters, issued an aggregate of 7,250,000 Common Shares at a price of $4.10 per Common Share for aggregate gross proceeds of $29,725,000; and (ii) a non-brokered private placement financing of 1,250,000 Common Shares at a price of $4.10 per Common Share to certain investors, including insiders, identified by Storm for aggregate gross proceeds of $5,125,000.

DESCRIPTION OF THE BUSINESS

General

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

Storm's business objective involves the identification and exploitation of opportunities to develop oil and natural gas assets profitably and consistently 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, the generation of its own prospects, 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 capacity to fund or its tolerance for risk.

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

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

The Corporation focuses on management of costs, both capital and operating. A low cost structure means that the Corporation can continue to execute its business plan and grow in periods of low commodity prices, such as prevailed during 2011, 2012, 2013 and into 2014 for natural gas prices, 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 existing and potential customers and partners are also exploring for oil and natural gas, and the results of such exploration efforts could affect the Corporation's ability to sell or supply oil or gas to these customers or participate in projects with joint venture partners in the future. The Corporation's ability to continue to bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into advantageous commercial arrangements is dependent upon the Corporation developing and maintaining close working relationships with its industry partners and its ability to select and evaluate suitable properties for acquisition and development and to consummate commercially attractive transactions in a highly competitive environment.

Cyclical Nature of Business

Storm's key properties, with the exception of the HRB in northeast British Columbia, generally provide year round access, enabling (subject to the imposition of seasonal road closures) drilling and other wellsite activities to continue throughout the year. In 2013, approximately 42% of Storm's revenue was generated from the sale of natural gas. Natural gas pricing is dependent on a wide range of factors, such as North American 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 saw 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 that natural gas markets are being supplied with gas from new wells with high initial deliverability. Oil and natural gas liquids prices have also fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas producing regions, pipeline access as well as geopolitical circumstances.

The acquisition of Bellamont in late March 2012 resulted in an increased percentage of higher value crude oil and natural gas liquids in the Corporation's commodity mix, resulting in higher netbacks and expanded cash flow. However, the Corporation's drilling program for the remainder of 2014 is expected to be focused on high NGL content natural gas prospects. Nevertheless, pricing for the Corporation's production is subject to market place inputs beyond the Corporation's capacity to control or influence.

Environmental Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to evolving international conventions and national, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. 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 and penalties, some of which may be material and the modification or cancellation of operating licences and permits. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines, increased potential for liability and potentially increased capital expenditures and operating costs. 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 and compensate affected third parties in the event that they are not covered by the Corporation's insurance. Enforcement of increasingly stringent environmental laws may potentially result in a curtailment of production or a material increase in the costs of production, development or exploration activities, or otherwise adversely affect the Corporation's financial condition, capital expenditures, results of operations and competitive position or prospects.

In the United States, and to a lesser extent in Canada, there has been considerable public concern that new fracturing technologies, which have resulted in exploitation of hitherto uneconomic natural gas in shale and similar tight deposits, can introduce chemicals to or otherwise damage or pollute surface water or underground water tables used to meet water demand in populated areas. The evolution of this concern is not foreseeable at this time. Nonetheless, the Corporation's properties at Umbach and the HRB involve exploitation of natural gas using fracturing technologies and it is possible that the Corporation will be subject to additional environmental controls, the future effect of which on the Corporation's operations cannot be determined at present.

In December 2011, Canada announced that it was withdrawing from the Kyoto Protocol to the United Nations Framework Convention on Climate Change, the key international convention on climate change. It is uncertain what effect this action will have on the long and medium term business of the Corporation. Nevertheless, there is considerable and increasing opposition, both domestic and international, to the extraction of crude oil from oilsands in Alberta which may have an indirect effect on the Corporation's operations as oilsands operations uses natural gas as an energy source as well as certain NGLs are used as a diluent when crude oil from oilsands is pipelined.

Specialized Skill and Knowledge

Exploration for and the acquisition, development of and production of oil, natural gas and natural gas liquids reserves requires specialized skills and knowledge in the areas of petroleum engineering, geophysics, geology, facility construction and land title. The Corporation has personnel with the required specialized skills and knowledge. While the current labour market in the industry is highly competitive, the Corporation expects to be able to attract and retain appropriately qualified employees throughout 2014.

Renegotiation or Termination of Contracts

Within the knowledge of management, the Corporation is not a party to any material contract that may be subject to renegotiation or termination in 2014.

Employees

As of December 31, 2013, the Corporation had 22 full-time employees and 4 contract employees.

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)
Stuart G. Clark(1) Priddis, Alberta	Chairman and Director	June 8, 2010
Brian Lavergne Calgary, Alberta	President, Chief Executive Officer and Director	June 8, 2010
Donald G. McLean Calgary, Alberta	Chief Financial Officer	-
Robert S. Tiberio Calgary, Alberta	Chief Operating Officer	-
John J. Devlin Calgary, Alberta	Vice President, Finance	-
Gregory G. Turnbull, QC(3)(6) Calgary, Alberta	Director	June 8, 2010
Matthew J. Brister(2)(3)(6) Calgary, Alberta	Director	June 8, 2010

Name and Municipality of Residence	Position Held	Date First Elected or Appointed as Director[5]
John A. Brussa[6] Calgary, Alberta	Director	June 8, 2010
Mark A. Butler[1][2][4] Calgary, Alberta	Director	June 8, 2010
P. Grant Wierzba[2][3][6] 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.
(6) On November 14, 2013: (i) Messrs. Brussa and Turnbull ceased to be members of the Compensation, Governance and Nominating Committee; (ii) Mr. Turnbull was appointed to the Reserves Committee; and (iii) Messrs. Brister and Wierzba were appointed to the Compensation, Governance and Nominating Committee.

As at the date hereof, the officers and directors, as a group, held, directly or indirectly, or exercise control or direction over 13,637,588 Common Shares.

Each of Messrs. Lavergne, McLean, Tiberio and Devlin devotes his 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 31, 2014 are set forth below.

Stuart G. Clark, Chairman and Director

Age: 59. Mr. Clark has been a director and Chairman of Storm since June 8, 2010. Mr. Clark was also a director of SEO from June 2004 to August 17, 2010. Mr. Clark has served as a director and Chairman of Rock Energy Inc. since January 2004 and has been a director of Chinook Energy Inc. since June 2009. Mr. Clark was also a director of Bellamont from November 2009 to March 2012. Mr. Clark also serves as a director of a number of private companies. Mr. Clark is a retired businessman and holds a Bachelor of Commerce (Honours) from the University of Manitoba.

Brian Lavergne, President, Chief Executive Officer and Director

Age: 48. Mr. Lavergne has been the President and Chief Executive Officer and a director of Storm since June 8, 2010. Prior thereto, Mr. Lavergne was the President and Chief Executive Officer and a director of SEO from June 2004 to August 17, 2010. Mr. Lavergne holds a Bachelor of Science in Mechanical Engineering from the University of Alberta (1989).

Donald G. McLean, Chief Financial Officer

Age: 67. Mr. McLean has been the Chief Financial Officer of Storm since June 8, 2010. Prior thereto, Mr. McLean was Vice President, Finance and Chief Financial Officer of SEO from June 2004 to August 17, 2010. Mr. McLean is a member of the Institute of Chartered Accountants of Alberta.

Robert S. Tiberio, Chief Operating Officer

Age: 49. Mr. Tiberio has been the Chief Operating Officer of Storm since August 18, 2010. Prior thereto, Mr. Tiberio was Chief Operating Officer of SEO from June 2004 to August 17, 2010.

John J. Devlin, Vice President, Finance

Age: 56. Mr. Devlin was appointed Vice President, Finance of Storm on March 3, 2011. Prior thereto, Mr. Devlin was the Controller of Storm from August 18, 2010 to March 3, 2011. Mr. Devlin was the Controller of SEO from January 2005 until August 17, 2010.

Gregory G. Turnbull, QC, Director

Age: 59. Mr. Turnbull is a senior partner at McCarthy Tétrault LLP, which he joined in July, 2002. Mr. Turnbull was a director of SEO. Mr. Turnbull is currently a director of Crescent Point Energy Corp., Heritage Oil PLC, Hyperion Exploration Corp., Sunshine Oilsands Ltd. and Marquee Energy Ltd., all publicly traded entities listed on the London Stock Exchange, the Hong Kong Stock Exchange, the Toronto Stock Exchange or the TSXV. Mr. Turnbull is also currently a director of a number of private companies.

Matthew J. Brister, Director

Age: 55. Mr. Brister is a director and Chairman of the Board of Chinook Energy Inc. and was President and Chief Executive Officer until December 31, 2013. Mr. Brister was a director of SEO from May 2008 until August 17, 2010. Mr. Brister holds a Bachelor of Science in Geology from the University of Calgary.

John A. Brussa, Director

Age: 57. Mr. Brussa is Vice Chairman and a partner at Burnet, Duckworth & Palmer LLP, a firm specializing in the energy sector, where he is the head of the Tax Department. He sits on the board of a number of public and private corporations in the energy, energy services, financial and marketing sectors. Mr. Brussa was a director of SEO. He is the non-executive Chairman of Crew Energy Inc.

P. Grant Wierzba, Director

Age: 63. Mr. Wierzba is a director of Chinook Energy Inc. and was Vice President, Operations until December 31, 2013. Mr. Wierzba was a director of SEO. Mr. Wierzba holds a Bachelor of Science in Engineering from the University of Alberta.

Mark A. Butler, Director

Age: 52. Mr. Butler is a business consultant and was a director of SEO. Mr. Butler is the past 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.

James K. Wilson, Director

Age: 61. Mr. Wilson has been a director of Storm since June 8, 2010. Prior thereto, he was a director of SEO from February 2010 until August 17, 2010. He is currently the Managing Director of Walwil Resources Ltd., an oil and gas financial consulting company. From May 2011 to February 2013, Mr. Wilson was Chief Financial Officer of Mako Hydrocarbons Ltd., a public junior oil and gas company. From September 2004 until October 2010, he was Vice President, Finance and Chief Financial Officer of Grizzly Resources Ltd. Mr. Wilson maintains memberships in the Institute of Corporate Directors, Financial Executives International of Canada and the Institute of Chartered Accountants of Alberta. Mr. Wilson holds a Bachelor of Commerce degree from the University of Calgary, Chartered Accountant designation and ICD.D director certification from the Institute of Corporate Directors.

Corporate Cease Trade Orders or Bankruptcies

To the knowledge of management of the Corporation, other than as set forth below, there has been no director or officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation that is, or within the 10 years before the date of this Annual Information Form, has been a director or officer of any other issuer that, while that person was acting in that capacity:

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

(b) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the other issuer being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(c) 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.

Mr. Gregory G. Turnbull, a director of the Corporation, was a director of Action Energy Inc., a corporation engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed into receivership on October 28, 2009 by its major creditor and Mr. Turnbull resigned as a director immediately thereafter.

Penalties or Sanctions

To the knowledge of management of the Corporation, no director or officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has:

(a) 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

(b) 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.

Personal Bankruptcies

To the knowledge of management of the Corporation, there has been no director or officer, or any shareholder holding sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person that has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or officer.

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

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

Legal Proceedings and Regulatory Actions

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

Interest of Management and Others in Material Transactions

None of the current executive officers or directors of Storm, or any person who is the direct or indirect owner of, or who exercises control over more than 10 percent of any class of securities of Storm, nor any associate or affiliate of such officers or directors or person has or has had any material interest, direct or indirect, in any transaction or proposed transaction that has materially affected or would materially affect Storm.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

The InSite Report evaluated Storm's crude oil, NGL and natural gas reserves. The InSite December 31, 2013 future price forecast was used to determine all estimates of future net revenue. The tables below are a summary of Storm's crude oil, NGL and natural gas reserves and the net present value of future net revenue attributed to such reserves as evaluated in the InSite Report based on constant and 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, production costs, development costs, future capital expenditures, and well abandonment costs for only those wells assigned reserves by InSite. The net present value is stated both before and after future income tax. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by InSite represents the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of Storm's crude oil, NGL and natural gas 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			
	Light Crude Oil	Sales Gas	Natural Gas Liquids	6:1 Oil Equivalent	Light Crude Oil	Sales Gas	Natural Gas Liquids	6:1 Oil Equivalent
	(Mbbls)	(Mmcf)	(Mbbls)	(Mboe)	(Mbbls)	(Mmcf)	(Mbbls)	(Mboe)
Proved								
Developed Producing	1,123	32,719	1,003	7,579	946	25,744	795	6,032
Developed Non-Producing	–	123	2	22	–	103	1	18
Undeveloped	300	65,758	1,903	13,163	255	48,868	1,523	9,923
Total Proved	1,423	98,600	2,908	20,764	1,201	74,715	2,319	15,973
Probable	870	99,177	2,378	19,777	748	75,514	1,907	15,241
Total Proved plus Probable	2,293	197,777	5,286	40,541	1,949	150,229	4,226	31,214

Numbers in this table may not add due to rounding.

Capital Program Efficiency with All-In Finding, Development and Acquisition Costs

Based on the evaluation of the Corporation's petroleum and natural gas reserves prepared by the independent reserve evaluator, InSite, the efficiency of capital programs is summarized in the following table.

	2013	2012	2011
	($/Boe)	($/Boe)	($/Boe)
FD&A Costs – Proved			
Exploration and development[(1)]	15.86	13.77	20.04
Acquisitions (net of dispositions)	(17.47)	26.88	24.35
Total	13.19	21.85	20.87
FD&A Costs – Proved Plus Probable			
Exploration and development[(1)]	12.91	11.48	14.59
Acquisitions (net of dispositions)	(14.69)	18.26	21.26
Total	9.79	16.26	15.39
Operating Netback per Boe[(2)]	20.43	21.22	22.81
Recycle Ratio Based on Operating Netback[(2)]			
Proved Plus Probable	2.1	1.3	1.5

Notes:

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

(2) Recycle ratio is calculated as operating netback divided by FD&A costs (proved plus probable including FDC). Operating netback is calculated as revenue (excluding realized hedging gains and losses) minus royalties, operating expenses and transportation expenses.

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

	Before Future Income Tax and Discounted at				
	0%	5%	10%	15%	20%
	($M)	*($M)*	*($M)*	*($M)*	*($M)*
Proved					
Developed Producing	184,439	146,816	122,247	105,198	92,774
Developed Non-Producing	92	87	82	78	74
Undeveloped	184,537	107,293	62,108	34,079	15,855
Total Proved	369,068	254,196	184,438	139,355	108,704
Probable	364,989	197,446	113,383	67,039	39,544
Total Proved plus Probable	734,058	451,643	297,821	206,393	148,248

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	184,439	146,816	122,247	105,198	92,774
Developed Non-Producing	92	87	82	78	74
Undeveloped	162,353	95,685	55,755	30,462	13,725
Total Proved	346,884	242,588	178,084	135,738	106,574
Probable	274,236	146,917	82,937	47,569	26,517
Total Proved plus Probable	621,121	389,504	261,021	183,308	133,091

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	933,412	144,364	257,666	159,475	2,840	369,068	22,184	346,884
Total Proved plus Probable	1,850,263	287,285	505,736	318,869	4,315	734,058	112,937	621,121

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

		Future Net Revenue Before Income Taxes (Discounted at 10%) ($M)	**Unit Value ($/Bbl) ($/Mcf)**
Proved	Light and Medium Crude Oil	37,366	31.11
	Natural Gas	147,072	2.09
	Total	184,438	
Proved Plus Probable	Light and Medium Crude Oil	52,061	26.71
	Natural Gas	245,760	1.78
	Total	297,821	

Future net revenues from natural gas exclude solution gas but do include the value of natural gas liquids. 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, 2013 in estimating the Corporation's reserves data using forecast prices and costs (before deduction of transportation costs).

	Natural Gas		**Crude Oil**		**Natural Gas Liquids**			
Year	Henry Hub	AECO-C Spot	WTI @ Cushing	EDM Ref Price	Butane	Propane	Inflation Rate	CDN/U.S. Exchange Rate
	($U.S./Mmbtu)	($Cdn/Mmbtu)	($U.S./Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	(%/yr)	($U.S./$Cdn)
2014	4.25	3.99	96.00	96.05	76.84	48.03	0%	0.95
2015	4.40	4.14	95.00	97.50	78.00	53.63	2%	0.95
2016	4.75	4.50	95.00	97.45	77.96	53.60	2%	0.95
2017	5.00	4.75	95.00	97.40	77.92	53.57	2%	0.95
2018	5.25	5.01	96.00	98.40	78.72	54.12	2%	0.95
2019	5.50	5.26	97.00	99.40	79.52	54.67	2%	0.95
2020	5.61	5.37	98.94	101.39	81.11	55.76	2%	0.95
2021	5.72	5.47	100.92	103.41	82.73	56.88	2%	0.95
2022	5.84	5.58	102.94	105.48	84.39	58.02	2%	0.95
2023	5.95	5.69	105.00	107.59	86.07	59.18	2%	0.95
2024	6.07	5.81	107.10	109.74	87.80	60.36	2%	0.95

Year	Natural Gas: Henry Hub	Natural Gas: AECO-C Spot	Crude Oil: WTI @ Cushing	Crude Oil: EDM Ref Price	Natural Gas Liquids: Butane	Natural Gas Liquids: 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)
Thereafter +2% per annum								

	2013 Actual Price and InSite Forecast Price Storm Wellhead Oil Price (Cdn$/Bbl)	2013 Actual Price and InSite Forecast Price Storm Wellhead Gas Price (Cdn$./Mcf)	2013 Actual Price and InSite Forecast Price Storm Wellhead NGL Price (Cdn$/Bbl)
2013 Actual	87.26	3.65	70.33
2014(2)	83.19	4.36	79.39
2015(2)	83.67	4.50	81.40
2016(2)	83.82	4.94	82.25
2017(2)	84.08	5.11	82.33
2018(2)	86.06	5.39	83.03

Notes:

(1) 2013 actual wellhead price excludes hedging gains/losses and is after deduction of transportation costs.
(2) InSite forecast prices are after deduction of transportation costs.

Weighted average historical price realized by Storm for the year ended December 31, 2013 was $87.26/Bbl for crude oil, $70.33/Bbl for NGL and $3.65/Mcf for natural gas.

Reconciliations of Changes in Reserves and Future Gross Revenue

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

	Light and Medium Crude Oil			Associated and Non-Associated Gas			NGL		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved + Probable (Mmcf)	Gross Proved Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)
December 31, 2012	2,348.8	1,264.9	3,613.8	58,999.6	66,600.2	125,599.8	1,639.9	1,144.1	2,784
Discoveries	–	–	–	–	–	–	–	–	–
Extensions & Improved Recoveries	–	–	–	50,711.9	41,575.3	92,287.2	1,885.2	1,537.9	3,423.1
Technical Revisions	(54)	(153)	(207)	2,341.7	1,354.7	3,696.4	(414.1)	(298.9)	(713)
Acquisitions	–	–	–	–	–	–	–	–	–
Dispositions	(702.9)	(242.2)	(945.2)	(796)	(184.7)	(980.7)	(23.2)	(5.2)	(28.4)
Economic Factors(1)	–	–	–	(6,895.7)	(10,169.3)	(17,065.0)	–	–	–
Production	(168.7)	–	(168.7)	(5,762.4)	–	(5,762.4)	(180.4)	–	(180.4)
December 31, 2013	1,423.2	869.7	2,292.9	98,599.9	99,176.6	197,776.5	2,907.4	2,377.8	5,285.2

Numbers in this table may not add due to rounding.

Note:

(1) Economic factors relate to removal of two future horizontal drilling locations in the Horn River Basin.

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	Natural Gas (MMcf)		Crude Oil (Mbbls)		Natural Gas Liquids (Mbbls)		Heavy Oils (Mbbls)	
	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end
Prior	–	–	–	–	–	–	–	–
December 31, 2011	12,037.9	12,037.9	–	–	139.8	139.8	–	–
December 31, 2012	27,029.7	39,067.6	300.0	300.0	937.4	1,077.2	–	–
December 31, 2013	33,750.0	65,758.1	–	300.0	1,248.1	1,903.1	–	–

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	Natural Gas (MMcf)		Crude Oil (Mbbls)		Natural Gas Liquids (Mbbls)		Heavy Oils (Mbbls)	
	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end
Prior	9,309.5	9,309.5	–	–	61.2	61.2	–	–
December 31, 2011	11,819.5	21,129.0	–	–	223.1	284.3	–	–
December 31, 2012	32,002.3	53,131.3	864.1	864.1	567.2	851.5	–	–
December 31, 2013	33,210.0	78,297.4	–	642.3	1,228.2	1,836.1	–	–

Proved and probable undeveloped reserves are determined by InSite based on accepted engineering and geological practices as defined under NI 51-101. These practices included the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information and the optimization of existing fields. The Corporation is focusing the 2014 drilling program on high NGL content natural gas prospects in the Umbach area of northeast British Columbia.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions 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).

	Forecast Prices and Costs	
	Proved	Proved Plus Probable
	($M)	($M)
2014	62,950	67,800
2015	13,107	75,888
2016	48,472	63,454
2017	34,946	78,572
2018	–	33,155
2019	–	–
Total Undiscounted	159,475	318,869
Total Discounted at 10% per year	134,383	259,220

The Corporation typically has four sources of funding available to finance its capital expenditure program: (i) internally generated cash flow from operations; (ii) bank financing when the Corporation's asset base can be used as collateral for bank borrowings; (iii) the issuance of new equity; and (iv) dispositions of non-core producing assets, investments and undeveloped land. The Corporation estimates that these sources are sufficient to fund the future development costs disclosed above.

Future development costs total $159.5 million on a total proved basis and $318.9 million on a total proved plus probable basis. A breakdown of these amounts is provided below.

Proved		
HRB	2.0 net horizontals plus infrastructure	$ 34.9 million
Umbach	20.6 net horizontals plus infrastructure	$ 117.0 million
Grande Prairie	3.0 net horizontals at Grimshaw	$ 7.6 million
Total		$ 159.5 million

Proved Plus Probable Additional		
HRB	5.0 net horizontals plus infrastructure	$ 83.8 million
Umbach	36.0 net horizontals plus infrastructure	$ 197.9 million
Grande Prairie	5.0 net horizontals at Grimshaw; 5.0 net horizontals at GP Montney; and 1.0 net horizontal at GP Dunvegan	$ 37.2 million
Total		**$ 318.9 million**

In 2014, Storm plans to drill 10 gross horizontal wells (10.0 net) and complete and tie-in 9 horizontal wells (9.0 net), all in the Umbach area of northeast British Columbia.

The Corporation expects to fund its total 2014 capital program with internally generated cash flow, dispositions of non-core properties, plus a limited amount of debt. Quarterly fluctuations in sources of funding are expected. The Corporation may also sell marketable securities not core to Storm's business plan.

Oil and Gas Properties

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

Umbach, Northeast British Columbia

Storm's land holdings as at December 31, 2013 in Umbach, which include Montney rights, total 133 gross sections or 112 net sections (79,000 net acres). Production in 2013 averaged 1,947 Boe per day (22% NGL). Approximately 95% of Storm's $52.4MM capital investment in 2013 was invested in Umbach. Two project areas have been identified with Umbach North consisting of 54 gross sections of jointly owned lands (33 net sections with an average Storm working interest of approximately 60%) and Umbach South consisting of 79 sections of land at a 100% working interest.

In Umbach North, nine horizontal wells have been drilled with eight of the nine wells producing as of December 31, 2013. In Umbach South, six horizontal wells were drilled in 2013, five of which are producing as of December 31, 2013.

In 2014, Storm anticipates it will drill 10 gross horizontal wells (10.0 net) with 9 (9.0 net) being completed and tied in. Storm will also construct a new field compression facility, expandable from an initial capacity of 24 Mmcf per day to 48 Mmcf per day.

Subsequent to December 31, 2013, the Corporation purchased an additional 29 gross sections (29 net) as well as production from two wells totaling approximately 360 Boe per day.

Grande Prairie Area, Northwest Alberta

Production in this area comes from properties acquired through the transaction with Bellamont which closed in the first quarter of 2012. Production in 2013 averaged 1,340 Boe per day with approximately 36% crude oil and has a stable decline rate, providing reasonably sustainable, high netback cash flow. The Company invested no capital on the properties in 2013 as funds flow was reinvested to grow Umbach. Minimal activity is planned during 2014. In 2014, cash flow from this area will continue to be re-invested to grow production at Umbach.

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, 2013, Storm has a 100% working interest in 123 sections in the HRB (81,000 net acres) which is prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Fourth quarter 2013 production averaged 363 Boe/d. Wellsite compression was installed in November 2013 and production has increased to average 400 Boe/d in the first quarter of 2014. Production is from one horizontal well with 12 fracture stimulations with cumulative production of 3.8 Bcf gross raw gas since start-up in March 2011. A second horizontal well was also drilled in 2011 and is awaiting completion with timing dependent on natural gas pricing.

A resource evaluation completed by InSite effective December 31, 2011 estimates that the best estimate of DPIIP in the core producing area is 3.1 Tcf gross raw gas with the best estimate of contingent resources being 616 Bcf. The evaluated area includes 30 sections at a 100% working interest and represents 22% of Storm's total land holdings in the HRB. Commerciality has been proven across the core producing area with a horizontal well that has been producing for 30 months plus two vertical wells that were completed and tested with final test rates of 900 Mcf per day over the final 24 hours of each flow test.

Storm faces no immediate land expiries and has no plans for additional activity in the area until there is evidence of a substantial and sustainable increase in natural gas prices.

Oil and Gas Wells

The following table summarizes the Corporation's interest as at December 31, 2013 in wells that are producing and non-producing.

	Producing Wells				**Non-Producing Wells**			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	25.0	21.7	12.0	10.9	18.0	14.7	49.0	29.1
British Columbia	–	–	15.0	11.8	–	–	31.0	24.5
Total	25.0	21.7	27.0	22.7	18.0	14.7	80.0	53.6

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, 2013 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, as at December 31, 2013.

	Gross Acres	**Net Acres**	**Net Acres Expiring Within One Year**
Horn River Basin – BC	82,105	79,852	3,255
Umbach Montney– BC	80,482	70,262	6,345
Grande Prairie - AB	38,131	32,207	3,456
Other areas	156,174	103,274	6,533
Total	**356,893**	**285,594**	**19,589**

Notes:

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

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

Forward Contracts

Storm is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by Storm to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The following table sets out Storm's forward contracts at December 31, 2013:

Commodity	**Type**	**Term**	**Volume**	**Price (Cdn$)**	**Index**
Crude Oil	Swap	January 2014 – March 2014	150 Bbls/day	$100.45	WTI
Crude Oil	Swap	January 2014 – March 2014	100 Bbls/day	$101.40	WTI
Crude Oil	Swap	January 2014 – March 2014	100 Bbls/day	$102.00	WTI
Crude Oil	Swap	January 2014 – March 2014	100 Bbls/day	$103.25	WTI
Crude Oil	Swap	April 2014 – June 2014	100 Bbls/day	$103.85	WTI
Crude Oil	Swap	April 2014 – June 2014	100 Bbls/day	$101.60	WTI
Crude Oil	Swap	April 2014 – June 2014	100 Bbls/day	$102.20	WTI
Crude Oil	Swap	April 2014 – June 2014	150 Bbls/day	$102.05	WTI
Crude Oil	Swap	July 2014 – September 2014	100 Bbls/day	$100.20	WTI
Crude Oil	Swap	July 2014 – September 2014	100 Bbls/day	$99.65	WTI
Natural Gas	Swap	January 2014 – March 2014	3,000 GJ/day	$3.80	AECO
Natural Gas	Swap	April 2014 – December 2014	3,000 GJ/day	$3.43	AECO
Natural Gas	Swap	January 2014 – December 2014	2,000 GJ/day	$3.36	AECO
Natural Gas	Swap	January 2014 – December 2014	2,000 GJ/day	$3.445	AECO
Natural Gas	Swap	January 2014 – December 2014	2,500 GJ/day	$3.59	AECO

Commodity	Type	Term	Volume	Price (Cdn$)	Index
Natural Gas	Collar	January 2014 – March 2014	2,000 GJ/day	$3.00 - $3.65	AECO
Natural Gas	Collar	April 2014 – December 2014	2,000 GJ/day	$3.00 - $3.87	AECO
Natural Gas	Collar	January 2014 – December 2014	2,000 GJ/day	$3.25 - $3.62	AECO

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs are estimated based on current regulations, actual costs incurred to date, technology and industry standards. Costs to abandon approximately 46 (41.6 net) wells totalling $1.7 million net (undiscounted) are included in the estimate of future net revenue for the proved developed reserve categories. The present value of this cost is $0.75 million using a 10% discount rate. Abandonment and reclamation costs for future undeveloped drilling locations are not yet included. As well, this does not include abandonment and reclamation costs for wells with no reserves assigned and not in the InSite Report. As disclosed in the Corporation's audited consolidated financial statements for the year ended December 31, 2013, the total undiscounted amount required to settle the Corporation's future asset retirement obligations, including environmental remediation, is estimated to be $12.4 million. Based on the InSite Report, over the next three years, Storm's net well abandonment cost is expected to total $0.15 million.

Tax Horizon

As at December 31, 2013, the Corporation had resource pools and operating losses of approximately $283 million available for deduction against future taxable income. These existing pools, plus pool additions through the Corporation's capital program in 2014 and beyond, mean that the Corporation does not expect to pay income tax for a considerable number of years. However, measurement of losses and tax pools and their availability are subject to audit and reassessment by Canada Revenue Agency, potentially several years later.

Costs Incurred

The following table summarizes the Corporation's property acquisition costs, exploration costs and development costs for the year ended December 31, 2013, net of dispositions of properties of $19.5 million.

	Capital Investment ($M)			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Costs	8,782	37,409	17,612	8,136
Dispositions	(18,100)	-	(1,395)	-
Total ($M)	(9,318)	37,409	16,217	8,136

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, 2013.

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	–	–	–	–	–	–
Natural gas wells	6.0	5.6	2.0	2.0	8.0	7.6
Service wells	–	–	–	–	–	–
Stratigraphic test wells	–	–	–	–	–	–
Dry holes	–	–	1.0	1.0	1.0	1.0
Total	**6.0**	**5.6**	**3.0**	**3.0**	**9.0**	**8.6**

For the remainder of 2014, the Corporation will focus on further development in the Umbach area of northeast British Columbia including expanding infrastructure with a new field compression facility. Subject to the availability of capital, Storm intends to drill a total of 10 gross horizontal wells (10.0 net), complete and tie in 9 horizontal wells (9.0 net) all in the Umbach area.

Production Estimates

Gross – Production by Product

The following tables disclose for each product type the total volume of production estimated by InSite on a proved plus probable basis for 2014 based on the Corporation's reserves and ownership at December 31, 2013.

2014	**Crude Oil** (Mbbls)	**NGL** (Mbbls)	**Natural Gas** (Mmcf)	**Boe/d**
HRB	–	–	810	370
Umbach	–	334.4	8,401	4,752
Grande Prairie	143.7	26.6	1,324	1,071
Total	143.7	361.0	10,535	6,193

Net of Royalties – Production by Product

2014	**Crude Oil** (Mbbls)	**NGL** (Mbbls)	**Natural Gas** (Mmcf)	**Boe/d**
HRB	–	–	785	358
Umbach	–	268.8	6,181	3,559
Grande Prairie	108.5	19.4	1,125	864
Total	108.5	288.2	8,091	4,781

NI 51-101 requires that estimated production volumes net of royalties do not include the effect of the Gas Cost Allowance and Producer Cost of Service Allowance in Alberta and British Columbia which reduces the cash royalty payable (both are credits that offset the cost of processing and transporting the portion of production owing to the Crown as royalties).

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:

	2013 Quarter Ended			
	Q4 Dec. 31	**Q3** Sept. 30	**Q2**[(1)] June 30	**Q1** March 31
Average Daily Production[(1)]				
Oil (Bbls/d)	428	458	460	597
Liquids (Bbls/d)	695	600	484	261
Gas (Mcf/d)	21,898	16,458	15,098	9,780
Combined (Boe/d)	4,773	3,800	3,460	2,488
Average Price Received[(1)(3)]				
Oil ($/Bbl)	78.47	103.70	84.96	82.21
Liquids ($/Bbl)	70.10	73.98	67.68	67.08
Gas ($/Mcf)	3.88	3.12	3.96	3.46
Combined ($/Boe)	35.03	37.69	38.02	40.37
Royalties Paid				
Oil ($/Bbl)	20.52	26.09	19.46	16.02
Liquids ($/Bbl)	5.03	15.17	14.53	17.43
Gas ($/Mcf)	0.02	0.02	0.20	(0.10)
Combined ($/Boe)	2.65	5.62	5.49	5.27
Operating & Transportation Expenses				
Oil ($/Bbl)	12.53	12.84	12.76	15.31
Liquids ($/Bbl)	-	-	-	-
Gas ($/Mcf)	1.88	2.03	2.15	2.51
Combined ($/Boe)	9.73	10.36	11.08	13.54
Netback Received[(2)]				
Oil ($/Bbl)	35.97	48.93	48.00	45.94

	2013 Quarter Ended			
	Q4 Dec. 31	**Q3** Sept. 30	**Q2(1)** June 30	**Q1** March 31
Liquids ($/Bbl)	62.29	57.48	53.09	49.45
Gas ($/Mcf)	1.88	1.20	1.46	1.02
Combined ($/Boe)	20.91	20.16	20.12	20.24

Notes:

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

The following table sets out the production volumes for each of HRB, Umbach and Grande Prairie for the year ended December 31, 2013:

	Crude Oil (Mbbls)	**NGL** (Mbbls)	**Natural Gas** (Mmcf)
HRB	–	–	767
Umbach	–	156.6	3,325
Grande Prairie	177.0	30.1	1,691
Total	**177.0**	**186.7**	**5,783**

DIVIDENDS AND DISTRIBUTIONS

The Corporation has not declared or paid any dividends on its Common Shares since the plan of arrangement involving the Corporation and certain of its predecessors, effective August 17, 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 31, 2014, an aggregate of 109,612,312 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

On August 31, 2010, the Common Shares were listed and posted for trading on the TSXV under the symbol "SRX". The following table sets forth the price range and trading volume of these securities as reported by the TSXV for the period January 1, 2013 to December 31, 2013.

Month	High ($)	Low ($)	Volume
January 2013	1.93	1.57	288,000
February 2013	1.87	1.45	1,390,000
March 2013	2.15	1.71	1,129,600
April 2013	2.15	1.87	3,765,600
May 2013	2.50	2.00	3,834,500
June 2013	2.70	2.23	930,400
July 2013	3.19	2.60	1,111,400
August 2013	3.49	2.73	2,496,800
September 2013	3.80	3.41	2,526,500
October 2013	3.77	3.29	2,417,700
November 2013	4.01	3.50	2,109,200
December 2013	4.26	3.66	1,069,200

INDUSTRY CONDITIONS

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

Pricing and Marketing - Oil and Natural Gas

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

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

The lack of pipeline capacity continues to limit the ability to produce and market natural gas production although pipeline expansions are ongoing. In addition, the prorationing of capacity on the interprovincial pipeline systems continues to limit oil exports.

In addition, recent years have seen the emergence of new sources of supply as natural gas deposits formerly regarded as inaccessible, particularly those locked in shales and other tight formations, both in Canada and the U.S., are now being exploited through new drilling and fracturing applications. Successful natural gas wells from these sources tend to be characterized by very high initial production volumes, which decline rapidly. From 2009 onwards, increased supply of natural gas from these sources, coupled with other factors such as reduced residential and industrial demand, resulted in a decrease in the price for natural gas, although prices have increased in the first part of 2014 largely due to a colder than anticipated winter. The effect on natural gas supply, as production of shale and other tight gas matures, cannot be determined, but the contribution of shale gas to aggregate supply will likely have a continuing and considerable influence on natural gas pricing, at least in the short and medium term.

From 2009 through to 2014, Pacific Rim countries, particularly China, Japan and South Korea, through sovereign oil companies, or representatives of end users, have expressed interest in or invested in, infrastructure projects and exploration and development activities in Canada, with a view to securing sources of future supply. Infrastructure projects have a long lead time, but if consummated, may result in Canada becoming a significant exporter of liquified natural gas to the Pacific Rim, as an additional or successor market to the U.S. It may also lead to future internationalization of pricing for natural gas.

Pricing for natural gas is also affected by storage levels, which are built up in summer months and depleted in winter. Recent years have seen storage levels at the beginning of the winter withdrawal season higher than historical averages. It is possible that this situation will not be the case in 2014.

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada - U.S. Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

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 significant factor in the profitability of crude oil, natural gas liquids, 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, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the provincial governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty reductions, royalty holidays and credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving near-term earnings and cash flow within the industry.

British Columbia

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties plus production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production if it is not more than either: (i) the monthly allowable production multiplied by 36; or (ii) 11,450 m^3 produced. The royalties for third tier oil are the lowest, reflecting the higher costs of exploration and extraction that the producers would incur.

The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas which may otherwise have been flared, natural gas conserved and produced in association with oil has a lower royalty than the royalty payable on non-conservation gas.

British Columbia has put in place a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- Deep Royalty Credit Program applies to vertical and horizontal natural gas wells but not to gas wells that are part of a coalbed methane project. To qualify, horizontal wells with a spud date after August 31, 2009 must have a true vertical depth to completion point of 1,900 metres and vertical wells must have a depth greater than 2,500 metres. However, a gas well event in a well with a spud date after August 31, 2009 will not receive a deep well credit if the well event is ultra-marginal. Recent changes result in a minimum royalty of 3% being applied to production from wells benefiting from this program. Additional changes, effective April 1, 2014, result in wells with a depth of less than 1,900 metres also qualifying for this credit. A minimum royalty of 6% will apply to wells with a depth of less than 1,900 metres;

- Deep Re-Entry Royalty Credit Program providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres which increases with the incremental distance drilled. A well can qualify for both the deep well and deep re-entry credits;

- Deep Discovery Royalty Credit Program providing the lesser of a three-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres with surface locations that are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- Coalbed Gas Royalty Reduction and Credit Program providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for certain wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- Marginal Royalty Reduction Program providing a royalty reduction for low productivity natural gas wells which have a spud date after May 31, 1998, average monthly production under 25,000 m^3

per day, and average daily production over the first 12 calendar months of less than 23 m^3 for every metre of well depth;

- Ultra-Marginal Royalty Reduction Program provides a royalty reduction for low productivity natural gas wells spudded or re-entered after December 31, 2005 with a true vertical depth of less than 2,300 metres for horizontal wells and less than 2,500 metres for vertical wells, average monthly production under 60,000 m^3 per day, and average daily production less than 11 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every metre of well depth over the first 12 calendar months;

Oil produced from an oil well event on either Crown or freehold land and completed in a new pool discovery subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible access to new and underdeveloped oil and gas areas. In 2014, the Government of British Columbia will provide $120 million in royalty credits to oil and gas companies under this program.

Alberta

In Alberta, the Crown royalty rates on conventional oil and natural gas vary depending on when a well was drilled, well depth, well production volume and the price of oil and natural gas. On October 25, 2007, the Alberta provincial government introduced a revised royalty regime effective January 1, 2009 applicable to new and existing conventional oil and natural gas wells in Alberta (the "**New Royalty Framework**"). New regulations, including the *Petroleum Royalty Regulation, 2009* and the *Natural Gas Royalty Regulation, 2009*, have now come into force in Alberta implementing the announced royalty changes pursuant to the *Mines and Minerals Act*. The new royalty regime assesses the Alberta royalty rate on a well-by-well basis using a sliding scale which takes into account both the commodity price and well production volumes.

In late November of 2008, the Alberta provincial government announced an optional five-year transitional royalty program that applies to new conventional oil and natural gas wells drilled with a spud date on or after November 19, 2008, with measured depths from 1,000 to 3,500 metres. For each eligible well, the Corporation may make a one time election to produce the well under transitional royalty rates or the new royalty rates. The transitional royalty formulas only apply to production from January 1, 2009 until December 31, 2013. As of January 1, 2014, all production subject to the transitional program will be subject to the new royalty regime.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program, a $200 per metre royalty credit was available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2011, subject to certain maximum amounts. The maximum credits available were determined by a company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2011. The new well incentive program applies to certain wells beginning production of conventional oil and natural gas after April 1, 2009 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum volume including all products of 7,949 cubic metres equivalent for oil wells and 14,100 cubic metres equivalent for gas wells.

On May 27, 2010 the Government of Alberta announced changes to the New Royalty Framework which became effective January 1, 2011. Changes include making the Natural Gas Deep Drilling Program, which adjusts the royalties for deep gas wells, a permanent initiative under the New Royalty Framework. Qualifying wells under the Natural Gas Deep Drilling Program include natural gas wells with gas-oil ratios of greater than 1,800:1 which have been spud or deepened on or after May 1, 2010 and have a true vertical depth greater than 2,000 metres. An Emerging Resources and Technologies Initiative has also been created to encourage new exploration and development from higher cost and more technically challenging resources, such as shale gas, coal seams and horizontal oil and gas wells.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

In Alberta, the New Royalty Framework includes a policy of "shallow rights reversion" which provides, for the first time in Western Canada, for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Protection Requirements

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

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. Furthermore, the Corporation expects incremental future compliance costs in light of increasingly complex environmental protection requirements, some of which may require the installation of emissions monitoring and measuring devices, and the verification and reporting of emissions data.

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

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

The oil and gas industry is subject to such environmental regulations which include restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

As at December 31, 2013, the Corporation owned approximately 150 gross and 112.7 net wells for which abandonment and reclamation costs are expected to be incurred. As disclosed in the Corporation's audited consolidated financial statements for the year ended December 31, 2013, the total undiscounted amount required to settle the Corporation's future asset retirement obligations, including environmental remediation, is estimated to be $12.4 million. The Corporation estimates abandonment and reclamation costs by taking account of the costs associated with decommissioning, abandonment, remediation and reclamation, all adjusted according to the Corporation's working interest and appropriately discounted. Such costs are individually attributed to assets then aggregated to determine the aggregate liability and are not reduced by salvage values.

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

The Corporation anticipates increased capital and operating expenditures as a result of increasingly stringent laws relating to the protection of the environment. No assurance can be given however that environmental laws will not result in a curtailment of production or a material increase in the costs of production, and 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.

International and Domestic GHG Regulations

Federal

In common with all producers, the Corporation's exploration activities and production facilities emit carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases" ("**GHG**") which directly subjects the Corporation to proposed legislation regulating emissions of GHGs in British Columbia.

Canada was a signatory to the United Nations Framework Convention on Climate Change and in December 2002 ratified the Kyoto Protocol thereunder. The Kyoto Protocol requires Canada to reduce total GHG emissions nationally by 6% below Canada's 1990 levels in the 2008-2012 compliance period. This is an absolute GHG emissions reduction target. On December 12, 2011, Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for an upstream oil and gas facility and 10,000 Boe/d per company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

From December 7 to 18, 2009, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly to a 17% reduction from 2005 levels by 2020. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Canada's withdrawal from the Kyoto Protocol in December 2011 introduces further uncertainty into the direction of Federal policy.

Additionally, there remains ongoing uncertainty regarding Canada's short-term and long-term emissions reduction targets and whether such targets will be absolute or intensity based. The Government of Canada is now evaluating both domestic and North American options for a cap-and-trade regulatory regime. Facility owners across Canada await further information regarding Canada's approach to regulating GHG emissions. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

On March 5, 2013 the Government of Canada announced that environmental regulations which aim to curb the GHG emissions of Canada's oil and gas sector are in their final stages and that details of the regulations should be released by mid-2013. Although the nature of federal GHG regulations are unknown at this time, the Corporation anticipates that Government of Canada GHG regulations will apply to its operations in the future as the Corporation's production base begins to grow which will result in investment in facilities. As a result, additional costs will be incurred to comply with reduction requirements and to perform necessary monitoring, measurement, verification, and reporting of GHG emissions. Proposed federal compliance mechanisms include: early offset credits, credits for federal Technology Fund contributions, credits obtained from other regulated entities which improved beyond legal requirements, offset credits obtained from non-regulated entities which reduced or removed GHGs; or international Clean Development Mechanism Credits. The Corporation's facilities may use a number of strategies to meet federal requirements, including emissions trading, in house reductions, or investments in a technology fund to research and develop GHG reduction technologies.

British Columbia

The Government of British Columbia released an energy plan in February 2007 (the "**Energy Plan**") outlining a provincial environmental strategy reducing GHG emissions, which promotes investment in research and innovation, and world leadership in sustainable environmental management. To this end, the province has since implemented: an Innovative Clean Energy Fund; a new Net Profit Royalty Program; an Infrastructure Royal Credit Program; and a broad-based carbon tax on all fossil fuels consumed in the province (including natural gas flared at a wellhead or a processing facility). The BC carbon tax is currently $30/tonne of CO_2 equivalent. The carbon tax is revenue neutral, in that carbon tax revenue funds personal and business tax cuts by the Government of British Columbia. The Energy Plan contemplates various other initiatives, including: the elimination of flaring at producing wells and processing facilities by 2016; tight gas, coalbed gas and other unconventional development incentives; implementation of a petroleum registry; an oil and gas technology transfer incentive program; and incentives for increased recoveries from existing reserves.

In 2008, the Government of British Columbia introduced and enacted the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which provides the regulatory framework for the province's participation in the emissions cap-and-trade system proposed by Western Climate Initiative ("**WCI**"). The WCI is a partnership of seven U.S. states and four Canadian provinces, including British Columbia, Manitoba, Québec and Ontario, with the goal of reducing greenhouse gas emissions by 15 per cent below 2005 levels by 2020. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act (and the WCI regime) will establish an absolute cap on GHG emissions.

Reporting regulations came into force on January 1, 2010 requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to report their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party.. At present the Corporation has no facilities subject to these regulations.

The Government of British Columbia is in the process of assessing whether or not it will proceed with plans to participate in the WCI regional greenhouse gas cap and trade system. Draft emissions trading regulations and offsets regulation have been posted by the British Columbia Climate Action Secretariat, but have yet to be finalized. Under the regulations, certain facilities would be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in greenhouse gas emissions.

Alberta

On July 1, 2007, the *Specified Gas Emitters Regulation* came into force under Alberta's *Climate Change and Emissions Management Amendment Act* requiring Alberta facilities which emit more than 100,000 tonnes of GHGs annually to reduce their GHG emissions intensity by 12% (from average 2003-2005 levels). If a facility is not able to abate GHG emissions sufficiently to meet the reduction target, it may utilize the following compliance mechanisms: (i) emissions performance credits obtained from other regulated facilities; (ii) emissions offsets obtained from non-regulated facilities or projects which reduce or remove GHG emissions; or (iii) credits for contributions to the Climate Change and Emissions Management Fund. Regulated facilities may choose any combination of these compliance mechanisms to comply with their target. At present, the Corporation does not believe that it owns any facilities subject to this Alberta regulation. The Alberta Government also published a new climate change action plan in January of 2008 wherein it set an objective to deliver a 50% reduction in GHG emissions by 2050 compared to business as usual, by employing: (i) mandatory carbon capture and storage ("**CCS**") for certain facilities and development across all industrial sectors; (ii) energy efficiency and conservation; and (iii) research and investment in clean energy technologies, including carbon separation technologies to assist CCS.

The Corporation anticipates that future federal legislation may require the reduction of GHG emissions at the Corporation's operations and facilities. The existing Alberta legislation does not apply directly to any of the Corporation's facilities; nevertheless, the Corporation will be committed to meeting its responsibilities under any legislation involving GHG reduction requirements in the future, which may require the Corporation to increase capital and/or operating expenses. In addition, failure to comply with current or proposed regulations can have a material adverse effect on the Corporation's operations, operating expenses, compliance costs and/or may lead to the modification or cancellation of operating licenses and permits, penalties and other corrective actions.

RISK FACTORS

An investment in the Corporation should be considered speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, 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.

Substantial Capital Requirements and Liquidity

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production (including facility acquisition or construction) of oil and natural gas reserves in the future. If the Corporation does not have, or is unable to increase, revenues or reserves in the future, the Corporation may have limited ability to maintain cash 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 cash generated by operations, or from the sale of non-core assets will be available or sufficient to meet those requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Credit Facility Risk

The current Credit Facility is subject to renewal by April 30, 2014. There is a risk that the Credit Facility will not be renewed for the same amount or on the same terms or that the borrowing base will not be increased as a result of production growth to date and forecasted production growth. Although the Corporation believes that the Credit Facility will be sufficient for its immediate requirements, there can be no assurance that the amount will be adequate for the Corporation's future financial obligations including its capital expenditure program, or that additional funds will be available under the Credit Facility or from other sources.

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

Additional Funding Requirements

The Corporation's future cash flow may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's future revenues decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to attract the necessary capital to identify and increase reserves or to maintain its production. If the Corporation's cash flow from operations 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 available on terms acceptable to the Corporation.

Capital and Lending Markets

As a result of general economic uncertainties and, in particular, until very recently the low price for natural gas, the Corporation, along with other entities having substantial exposure to natural gas, may have reduced access to bank debt and to equity. As future capital expenditures will be financed out of funds from operations, bank borrowings if available, and possible equity issues, the Corporation's ability to do so is dependent on, among other factors, the overall state of lending and capital markets and investor and lender appetite for investments in the energy industry and the Corporation's securities in particular.

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could realize less than their carrying amount on the financial statements of the Corporation.

Royalties

Frequent changes to royalty regimes have created uncertainty surrounding the ability to accurately estimate future royalties and, correspondingly, cash flow, resulting in additional volatility and uncertainty for producers including the Corporation.

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 and in the marketing of oil and natural gas. The Corporation's competitors include companies which have greater financial resources, staff, access to land and facilities than those of the Corporation. The Corporation's ability to increase reserves in the future 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 and methods and reliability of delivery.

The marketability of oil and natural gas acquired or discovered is affected by numerous factors beyond the control of the Corporation. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing facilities and government regulation. Oil and natural gas operations (exploration, drilling, well completions and tie-ins, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government which may be amended from time-to-time. The Corporation's oil and natural gas operations are also subject to compliance with increasingly demanding federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Although the Corporation believes that it is in material compliance with current applicable environmental regulations, changing government regulations may have an adverse effect on the Corporation. [See "*Industry Conditions - Environmental Protection Requirements*" and "International and Domestic GHG Regulations".]

Volatility of Oil and Gas Prices

Both oil and natural gas prices are unstable and are subject to fluctuation. Material declines in commodity prices such as have affected natural gas in recent years could result in a reduction of the Corporation's future production revenue and funds from operations and could result in reserve and impairment test write-downs as happened in 2013. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes and value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could materially affect the Corporation's production revenue, and, correspondingly, internally generated cash flow, causing a reduction in its oil and gas exploration and development activities.

Operating Risks

Oil and natural gas exploration is subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, oil spills 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 nature of these risks is such that liabilities 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 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.

Availability of Equipment

Oil and natural gas exploration and development activities are dependent on the availability of drilling, completion and related equipment as well as experienced and competent crews in the particular areas where such activities will be conducted. Demand for equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. Further, to the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Environmental and Operational Matters

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 with a necessary permit, licence, or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose the Corporation to fines or penalties, third party liabilities or to the requirement to remediate, each of which could be material. The operational hazards associated with possible blowouts, accidents, oil 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. Oil and gas operations are also subject to specific operational risks which may have material operational and financial impact on the Corporation should they occur, such as drilling into unexpected formations or unexpected pressures, premature decline of reservoirs, and water invasion into producing formations. In addition, certain of the Corporation's wells will 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.

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.

There is currently uncertainty among industry as to the potential application and extent of GHG reduction requirements and potential compliance options. As a result, it is not possible to predict the operational and financial effects of future GHG emissions laws, if any, applicable to the Corporation.

Hedging Activities

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

Exchange Rate Fluctuations

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 will not benefit from the changing exchange rate.

Title Reviews

Although title reviews will be completed according to industry standards prior to the purchase of most oil and natural gas properties or the commencement of drilling wells, 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.

Reserves Estimate Uncertainty

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserve and cash flow information set forth in this Annual Information Form represent estimates only. The reserves and estimated future net cash flow from the Corporation's properties have been independently evaluated effective December 31, 2013 by InSite. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Financial Risks

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

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, Donald G. McLean, Robert S. Tiberio and John J. Devlin. 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. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Readers must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Dilution

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

Third Party Credit Risk

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

Forward-Looking Statements may Prove Inaccurate

Readers are cautioned not to place undue reliance on forward-looking information in this Annual Information Form. 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.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, no contracts entered into by the Corporation during the most recently completed financial year can reasonably be regarded as presently material to the Corporation. At present the Corporation has no material obligations with a term longer than twelve months except for a lease of office premises for a period of five years commencing October 1, 2013.

Except for contracts entered into in the ordinary course of business and contracts relating to the Umbach Acquisition and associated financing arrangements, no contracts entered into by the Corporation subsequent to the year ended 2013 can reasonably be regarded as presently material to the Corporation. See "*General Development of the Business – Subsequent Events to Year-Ended 2013*".

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 rules of professional conduct of the Institute of Chartered Accountants of Alberta.

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

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are Ernst & Young LLP, 1000, 440 - 2nd Avenue S.W., Calgary, Alberta, T2P 5E9.

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, 2013. Management and auditors' reports on the financial statements are dated March 6, 2014 and Management's Discussion and Analysis is dated March 6, 2014. 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

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

2. The report on reserves data referred to in item 2 of section 2.1 of NI 51-101, to be executed by one or more *qualified reserves evaluators or auditors independent of the reporting issuer*, must in all material respects be as follows:

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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated 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, 2013, 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, 2013 and dated February 24, 2014	Canada	–	$297,821,000	–	$297,821,000
Totals			**–**	**$297,821,000**	**–**	**$297,821,000**

[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.

5. 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.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

Executed as to our report referred to above:

InSite Petroleum Consultants Ltd., Calgary, Alberta, Canada

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

March 31, 2014

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, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

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

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

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

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

The Reserves Committee of the board of directors of the Company has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors of the Company has, on the recommendation of the Reserves Committee, approved:

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

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

(c) the content and filing of this report.

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

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

(signed) "Donald G. McLean"
Donald G. McLean
Chief Financial Officer

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

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

March 31, 2014