



STORM RESOURCES LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2011

MARCH 30, 2012

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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 or natural gas prices;
- future production levels;
- future revenues or costs or revenues or costs per commodity unit;
- future capital expenditures and their allocation to specific exploration and development activities or periods;
- future drilling of new wells;
- the timing of future recovery of reserves;
- future cash flows and earnings;
- future asset acquisitions or dispositions;
- future sources of funding for capital program;
- future decommissioning costs;
- future debt levels;
- availability of credit facilities;
- future tax liabilities;
- development plans;
- ultimate recoverability of reserves or resources;
- expected finding and development costs, operating costs, and general and administrative costs;
- estimates on a per-share basis;
- dates or time periods by which certain geographical areas will be developed; and
- changes to any of the foregoing.

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.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed

or implied by such statements. Such factors include the material risks described in this Annual Information Form under “*Risk Factors*” herein, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital, including bank debt, from internal and external sources. All of these caveats should be considered in the context of current economic conditions and reduced prices for natural gas, each of which is outside the control of Storm. 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’s actual results, performance or achievement, could differ materially from those expressed in, or implied by, these 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.

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 28° API or higher is generally referred to as light crude oil
Boe ⁽¹⁾	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
Cdn\$	Canadian dollar
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 this 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
Scf/ton	standard cubic foot per ton
TSX	Toronto Stock Exchange
TSXV	TSX Venture Exchange
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

Note:

- (1) The term Boe, or barrel of oil equivalent, can be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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

CURRENCY OF INFORMATION

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

DEFINITIONS

Wherever used in this Annual Information Form, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:

“**ABCA**” means the *Business Corporations Act* (Alberta);

“**Bellamont**” means Bellamont Exploration Ltd.;

“**Bellamont Arrangement**” has the meaning ascribed under the heading “*General Development of the Business –Subsequent Events to Year Ended 2011*”;

“**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.;

“HRB” means the Horn River Basin in northeast British Columbia;

“InSite” means InSite Petroleum Consultants Ltd.;

“InSite Report” means the report prepared by InSite, in accordance with NI 51-101, dated February 3, 2012 and effective December 31, 2011;

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

“NEB” means the National Energy Board;

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

“Plan of Arrangement” means the plan of arrangement involving the Corporation, Storm Exploration Inc., ARC Energy Trust and ARC Resources Ltd., effective as of August 17, 2010;

“Private Placement” has the meaning ascribed under the heading *“General Development of the Business – Subsequent Events to Year Ended 2011”*;

“SGR” means Storm Gas Resource Corp.;

“SGR Arrangement” has the meaning ascribed under the heading *“General Development of the Business – Subsequent Events to Year Ended 2011”*; and

“U.S.” or **“United States”** means the United States of America.

The information set out in this Annual Information Form is stated as at December 31, 2011 unless otherwise indicated.

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 30, 2012, the Corporation has one wholly-owned subsidiary, SGR, which was incorporated under the ABCA.

The Corporation’s registered office is located at 3300, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9, and its head and principal office is located at Suite 800, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 2V7.

GENERAL DEVELOPMENT OF THE BUSINESS

Year Ended 2010

Storm commenced oil and gas operations on August 17, 2010 as the successor company emerging from the Plan of Arrangement which resulted in the sale of Storm Exploration Inc. to ARC Energy Trust. Pursuant to the Plan of Arrangement, Storm Exploration Inc. transferred certain assets to the Corporation consisting of approximately 117,200 net acres located in the HRB, Cabin/Kotcho/Junior and Umbach areas in northeast British Columbia plus undeveloped land in the Red Earth area of north central Alberta. In addition, Storm Exploration Inc.'s share ownership positions in SGR (2.5 million shares), Bellamont (5.08 million shares), Bridge Energy Norge ASA (1.05 million shares) and Chinook Energy Inc. (4.5 million shares) were transferred to the Corporation. Pursuant to the Plan of Arrangement, Storm also received \$9.4 million of cash. By the end of 2010, undeveloped land grew to 144,000 net acres primarily as a result of acquiring an additional 17,100 net undeveloped acres at Umbach in northeast British Columbia which are prospective in the Montney formation.

Storm drilled five wells (1.8 net) in 2010 with a 100% success rate. These wells included one horizontal well (0.4 net) in the Muskwa/Otter Park formation of the HRB, two horizontal wells (0.4 net) in the Slave Point formation at Red Earth, Alberta, and one vertical delineation well (0.6 net) into the Montney formation at Umbach. In addition to the drilling activity, a standing horizontal well at Umbach (60% working interest) was completed in the Montney formation with seven 100 ton fracture treatments and had a final test rate of 4.6 Mmcf per day.

Year Ended 2011

On December 1, 2011, Storm completed the acquisition of 150 Boe/d in the Mica area of northeast British Columbia from an oil and gas company 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 NGLs 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.

The InSite Report assigns proved plus probable reserves as at December 31, 2011 in the amount of 8,322 Mboe and undeveloped lands of 148,500 net acres. See "*Statement of Reserves Data and Other Oil and Gas Information*".

Subsequent Events to Year Ended 2011

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 \$3.70 per Common Share, for the acquisition of all of the issued and outstanding common shares of SGR that were previously not 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 January 20, 2012, Storm entered into an arrangement agreement with Bellamont pursuant to which Storm agreed to acquire all of the issued and outstanding class A shares of Bellamont (the "**Bellamont Arrangement**"). On February 28, 2012, Storm entered into an agreement with its bankers to increase the Corporation's banking facility from \$18 million to \$70 million. The increase to the banking facility became effective on March 23, 2012 when the Bellamont Arrangement was completed.

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. 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 a brokered private placement of 2,353,000 Common Shares and 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 (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 estimated net debt of \$36.1 million, the total cost of the transaction was approximately \$95.8 million.

For the remainder of 2012, the Corporation will focus on integrating the Bellamont assets and the implementation of liquids-focused development programs at Storm's properties at Umbach in northeast British Columbia and at Grimshaw and Grande Prairie in Alberta. Subject to the availability of capital, the Corporation intends to drill a total of 8.0 gross wells (7.2 net), of which 2.0 to 3.0 gross horizontal wells (1.2 to 1.8 net) will be at Umbach, 5.0 gross wells (5.0 net) at Grimshaw and 1.0 to 3.0 gross wells (1.0 to 3.0 net) at Grande Prairie or Mica.

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, Grand Prairie and Red Earth 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 high 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) 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 and 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 maintain its momentum in periods of low commodity prices, such as prevailed during 2011 and into 2012 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 substantial 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 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 workover activities to continue throughout the year. In 2011, Storm's revenue was generated, for the most part, from the sale of natural gas. Natural gas pricing is dependent on a wide range of factors, such as storage levels, LNG imports, 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, throughout 2009, 2010, 2011 and into 2012, natural gas markets in North America received deliveries of increasing volumes of natural gas delivered 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 were supplied with gas from new wells with high initial deliverability.

The acquisition of the Mica properties in late 2011 and Bellamont in late March 2012 is expected to result 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. Furthermore, the Corporation's drilling program for the remainder of 2012 is expected to be focused on higher netback crude oil and high NGL content natural gas prospects. Nevertheless, pricing for crude oil and natural gas liquids is subject to market place influences beyond the Corporation's control or influence and the attractive pricing environment in the first quarter of 2012 for crude oil and NGLs may not be sustained.

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 a variety of 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 inaccessible 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 resolution of this concern is not foreseeable at this time. Nonetheless, the Corporation's properties located in the HRB involve exploitation of natural gas from shale deposits and it is possible that the Corporation will be subject to additional environmental controls, the future effect of which 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. It is uncertain whether this action will have any effect on the business of the Corporation.

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 2012.

Employees

As of December 31, 2011, the Corporation had 16 full-time employees and 3 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⁽⁴⁾
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	-
Daniel J. Fitzgerald Calgary, Alberta	Vice President, Corporate Development	-
John J. Devlin Calgary, Alberta	Vice President, Finance	-

Name and Municipality of Residence	Position Held	Date First Elected or Appointed as Director⁽⁴⁾
Gregory G. Turnbull, QC ⁽²⁾ Calgary, Alberta	Director	June 8, 2010
Matthew J. Brister ⁽³⁾ Calgary, Alberta	Director	June 8, 2010
John A. Brussa ⁽²⁾ Calgary, Alberta	Director	June 8, 2010
Mark A. Butler ^{(1) (2)} Calgary, Alberta	Director	June 8, 2010
P. Grant Wierzba ⁽³⁾ Calgary, Alberta	Director	June 8, 2010
James K. Wilson ⁽¹⁾ 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) The directors will hold office until the next annual meeting of holders of Common Shares or until their successor is duly elected or appointed, unless their office is earlier vacated in accordance with the By-laws.

As at the date hereof, the officers and directors, as a group, held, directly or indirectly, or exercise control or direction over 9,093,290 Common Shares.

Each of Messrs. Lavergne, McLean, Tiberio, Fitzgerald 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 30, 2012 are set forth below.

Stuart G. Clark, Chairman and Director

Age: 57. Mr. Clark has been a director and Chairman of Storm since June 8, 2010. Mr. Clark was also a director of Storm Exploration Inc. ("SEO") from June 2004 to August 17, 2010. Mr. Clark was also a director and Chairman of Focus Energy Trust since its inception in July 2002 until it was sold to Enerplus Resources Fund in February 2008. Mr. Clark has served as a director and Chairman of Rock Energy Inc. since January 2004 to present 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: 46. 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 was a director of SGR and SEO. Mr. Lavergne has a Bachelor of Science in Mechanical Engineering from the University of Alberta (1989).

Donald G. McLean, Chief Financial Officer

Age: 65. 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: 47. 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.

Daniel J. Fitzgerald, Vice President, Corporate Development

Age: 42. Mr. Fitzgerald has been the Vice President, Corporate Development of Storm since September 1, 2010. Prior thereto, Mr. Fitzgerald was Team Lead, Business Development at Enerplus Resources Fund from February 2008 to August 2010. Prior thereto he was Senior Development Engineer at Focus Energy Trust from June 2003 to February 2008. Mr. Fitzgerald is a professional engineer in the Province of Alberta, and has a Bachelor of Science in Chemical Engineering from the University of Calgary.

John J. Devlin, Vice President, Finance

Age: 54. 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: 57. Mr Turnbull is the Regional Managing Partner of 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., Hawk Exploration Ltd., Sonde Resources Corp., Online Energy Inc., Porto Energy Corp. and Sunshine Oilsands Ltd., all publicly traded entities listed on the London Stock Exchange, the Hong Kong Stock Exchange, the TSX or the TSXV. Mr. Turnbull is also currently a director of a number of private companies.

Matthew J. Brister, Director

Age: 53. Mr. Brister is the President and Chief Executive Officer and a director of Chinook Energy Inc. Mr. Brister was the Chairman of SEO from June 2004 until May 9, 2008 and a director from May 2008 until August 17, 2010. Mr. Brister is also a director of Bridge Energy ASA and was a director of SGR. Mr. Brister has a Bachelor of Science in Geology from the University of Calgary.

John A. Brussa, Director

Age: 55. Mr. Brussa is a barrister and solicitor with the firm of Burnet, Duckworth & Palmer LLP, a firm specializing in the energy sector, where he is a senior partner and head of the Tax Department. He sits on the board of a number of public and private corporations in the energy, energy services, construction, financial and marketing sectors. Mr. Brussa was a director of SEO. He is the non-executive Chairman of Penn West Petroleum Ltd. and Crew Energy Inc.

P. Grant Wierzba, Director

Age: 61. Mr. Wierzba is the Vice President Production and Chief Operating Officer, Canada and a director of Chinook Energy Inc. Mr. Wierzba was a director of SEO and SGR and is currently a director of Standard Exploration Ltd. Mr. Wierzba has a Bachelor of Science in Engineering from the University of Alberta.

Mark A. Butler, Director

Age: 50. Mr. Butler is a business consultant and, from June 2005 until December 2007, was President of WestPac LNG Corporation, a private company. Mr. Butler was a director of SEO. Mr. Butler holds a Bachelor of Laws degree from the University of Saskatchewan and a Masters of Business Administration from the University of Calgary.

James K. Wilson, Director

Age: 59. 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 Chief Financial Officer of Mako Energy Limited, a publicly traded junior oil and gas company, and the Managing Director of Walwil Resources Ltd., an oil and gas financial consulting company. From September 2004 until October 2010 he was Vice President, Finance and Chief Executive Officer for Grizzly Resources Ltd. Mr. Wilson is also a director of Rock Energy Inc. Mr. Wilson maintains memberships in the Institute of Corporate Directors, Financial Executives International of Canada, the Institute of Chartered Accountants of Alberta and Canadian Petroleum Tax Society. Mr. Wilson obtained his Bachelor of Commerce degree from the University of Calgary in 1976, a Chartered Accountant designation in 1979 and director certification in 2010.

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 company 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 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. Stuart Clark, a director and officer of the Corporation, was also a director of Bellamont. Mr. Clark declared his conflict and refrained from voting on any resolutions of the boards of Bellamont and Storm relating to the Bellamont Arrangement.

Mr. John A. Brussa, a director of the Corporation, is 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. Brussa is also a non-executive Chairman of Penn West Petroleum Ltd. which operates two horizontal oil wells in which Storm has a 20% working interest in the Red Earth area of north central Alberta.

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

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

AUDIT COMMITTEE

The purpose of Storm's Audit Committee is to provide assistance to the Board of Directors in fulfilling its legal fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and certain compliance functions of the Corporation. It is the objective of the Audit Committee to maintain a free and open means of communication among the Board of Directors, the independent auditors and the financial and senior management of the Corporation.

The full text of the Audit Committee's Charter is included as Appendix C to this Annual Information Form.

Composition of Audit Committee

The Audit Committee is comprised of James Wilson (Chairman), Stuart Clark and Mark Butler. Mr. Butler was appointed to the Audit Committee on March 3, 2011 to replace Mr. Brister. Each of the members of the Audit Committee is financially literate and independent as such terms are defined in Multilateral Instrument 52-110.

Relevant Education and Experience

See "*Management of the Corporation*" for descriptions of the Audit Committee members' relevant education and experience.

Pre-Approval Policies and Procedures

The Audit Committee has the authority to pre-approve non-audit services which may be required from time-to-time (see "*Specific Responsibilities and Duties - Other Responsibilities*" in the Audit Committee Charter attached as Appendix C to this Annual Information Form).

Audit Fees

The aggregate fees billed by the Corporation's external auditor for audit services for the fiscal year ended December 31, 2011 were \$37,000.

Audit-Related Fees

The aggregate fees billed by the Corporation's external auditor for the quarterly reviews of the Corporation's financial statements for the fiscal year ended December 31, 2011 were \$19,000.

Tax Fees and All Other Fees

Fees for additional services were \$31,000.

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, 2011 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 and general and administrative costs, but after providing for estimated royalties, transportation costs, production costs, development costs, other income, 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
	(Mbbbls)	(Mmcf)	(Mbbbls)	(Mboe)	(Mbbbls)	(Mmcf)	(Mbbbls)	(Mboe)
Proved								
Developed Producing	476	5,893	110	1,568	441	4,527	87	1,282
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	-	12,038	140	2,146	-	9,225	111	1,648
Total Proved	476	17,931	250	3,714	441	13,751	198	2,931
Probable	79	25,208	328	4,608	70	18,925	261	3,485
Total Proved plus Probable	555	43,139	578	8,322	511	32,676	459	6,416

Numbers in this table may not add due to rounding.

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

	Before Future Income Tax and Discounted at				
	0%	5%	10%	15%	20%
	(\$M)	(\$M)	(\$M)	(\$M)	(\$M)
Proved					
Developed Producing	52,462	37,803	29,777	24,746	21,304
Developed Non-Producing	-	-	-	-	-
Undeveloped	20,114	8,967	2,575	(1,282)	(3,694)
Total Proved	72,576	46,770	32,352	23,464	17,609
Probable	82,519	41,976	22,153	11,392	5,113
Total Proved plus Probable	155,095	88,747	54,505	34,856	22,722

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	52,462	37,803	29,777	24,746	21,303
Developed Non-Producing	-	-	-	-	-
Undeveloped	20,114	8,967	2,575	(1,282)	(3,694)
Total Proved	72,576	46,770	32,352	23,464	17,609
Probable	62,590	32,123	16,849	8,353	3,285
Total Proved plus Probable	135,166	78,893	49,201	31,817	20,894

Additional Information Concerning Future Net Revenue – (Undiscounted)

Reserves Category	Revenue (\$M)	Royalties (\$M)	Operating Costs (\$M)	Development Costs (\$M)	Abandonment and Reclamation Costs (\$M)	Future Net Revenue Before Income Tax (\$M)	Income Tax (\$M)	Future Net Revenue After Income Tax (\$M)
Total Proved	180,083	25,431	51,339	30,220	517	72,575	-	72,575
Total Proved plus Probable	389,150	62,093	98,401	72,782	779	155,095	19,929	135,166

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 (\$/Mcf) (\$/Bbl)
Proved	Light and Medium Crude Oil	16,798	\$35.28/Bbl
	Natural Gas	15,554	\$0.87/Mcf
	Total	32,352	
Proved Plus Probable	Light and Medium Crude Oil	18,500	\$33.36/Bbl
	Natural Gas	36,005	\$0.83/Mcf
	Total	54,505	

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.

Notes and Definitions

In the tables set forth above in “*Disclosure of Reserves Data*” and elsewhere in this Annual Information Form, the following notes and other definitions are applicable.

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:

- (g) **“associated gas”** means the gas cap overlying a crude oil accumulation in a reservoir.
- (h) **“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.
- (i) **“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.
- (j) **“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.
- (k) **“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.
- (l) **“exploratory well”** means a well that is not a development well, a service well or a stratigraphic test well.
- (m) **“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”.

- (n) **“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).
- (o) **“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.
- (p) **“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,.
- (q) **“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.
- (r) **“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.
- (s) **“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.
- (t) **“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.
- (u) **"non-associated gas"** means an accumulation of natural gas in a reservoir where there is no crude oil.
- (v) **"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.
- (w) **"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.
- (x) **"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.
- (y) **"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.
- (z) **"proved property"** means a property or part of a property to which reserves have been specifically attributed.
- (aa) **"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.

- (bb) **“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.
- (cc) **“solution gas”** means natural gas dissolved in crude oil.
- (dd) **“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”**.
- (ee) **“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.
- (ff) **“unproved property”** means a property or part of a property to which no reserves have been specifically attributed.
- (gg) **“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.

Pricing Assumptions – Forecast Prices and Costs

InSite employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2011 in estimating the Corporation’s reserves data using forecast prices and costs.

Year	Natural Gas		Crude Oil		Natural Gas Liquids		Inflation Rate (%/yr)	CDN/U.S. Exchange Rate (\$U.S./\$Cdn)
	Henry Hub (\$U.S./Mmbtu)	AECO-C Spot (\$Cdn/Mmbtu)	WTI @ Cushing (\$U.S./Bbl)	EDM Ref Price (\$Cdn/Bbl)	Butane (\$Cdn/Bbl)	Propane (\$Cdn/Bbl)		
2012	3.90	3.45	100.00	98.00	73.50	58.80	2%	1.00
2013	4.50	4.04	101.00	99.00	74.25	59.40	2%	1.00
2014	5.00	4.53	102.00	99.96	74.97	59.98	2%	1.00
2015	5.50	5.02	103.00	100.92	75.69	60.55	2%	1.00
2016	6.00	5.51	104.00	101.88	76.41	61.13	2%	1.00
2017	6.50	6.00	106.00	103.84	77.88	62.30	2%	1.00
2018	7.00	6.49	108.12	105.91	79.43	63.55	2%	1.00
2019	7.50	6.98	110.28	108.03	81.02	64.82	2%	1.00
2020	7.65	7.12	112.49	110.19	82.64	66.11	2%	1.00
2021	7.80	7.27	114.74	112.39	84.30	67.44	2%	1.00
2022	7.96	7.41	117.03	114.64	85.98	68.79	2%	1.00

Thereafter +2% per annum

	2011 Actual Price and InSite Forecast Price Storm Wellhead Oil Price (Cdn\$/Bbl)	2011 Actual Price and InSite Forecast Price Storm Wellhead Gas Price (Cdn\$/Mcf)	2011 Actual Price and InSite Forecast Price Storm Wellhead NGL Price (Cdn\$/Bbl)
2011 Actual	89.44	3.39	84.00
2012 ⁽²⁾	95.95	3.50	76.96
2013 ⁽²⁾	96.69	4.14	76.91
2014 ⁽²⁾	97.47	4.69	77.73
2015 ⁽²⁾	98.31	5.24	78.55
2016 ⁽²⁾	99.17	5.79	79.36

Notes:

- (1) 2011 actual wellhead price excludes hedging gains/losses and is after deduction of transportation costs.
(2) InSite forecast prices are after deduction of transportation costs.

Reconciliations of Changes in Reserves 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:

Factors	Light and Medium Crude Oil			Associated and Non-Associated Gas			NGL		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved + Probable (Mbbbl)	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved + Probable (Mmcf)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved + Probable (Mbbbl)
December 31, 2010	63.4	13.2	76.6	3,889.5	10,172.9	14,062.4	26.2	65.6	91.9
Discoveries	-	-	-	-	-	-	-	-	-
Extensions & Improved Recoveries	-	-	-	13,779.2	15,206.4	28,985.7	208.5	238.8	447.4
Technical Revisions	5.4	3.3	8.8	63.2	(345.9)	(282.7)	23.3	22.9	46.3
Acquisitions	432.6	62	494.6	1,167.1	174.4	1,341.5	7	1	8
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(25.5)	-	(25.5)	(968.4)	-	(968.4)	(15.4)	-	(15.4)
December 31, 2011	476	78.5	554.6	17,930.6	25,207.9	43,138.5	249.7	328.4	587.1

Numbers in this table may not add due to rounding.

Proved and Probable Undeveloped Reserves

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 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. 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.

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, 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)
2012	5,940	12,900
2013	16,024	29,162
2014	7,428	8,885
2015	828	16,380
2016	-	5,455
Total Undiscounted	30,220	72,782
Total Discounted at 10% per year	25,776	59,480

The Corporation estimates that its internally generated cash flow using forecast pricing in the InSite Report plus available cash and proceeds from the possible sale of marketable securities will be sufficient to fund the future development costs disclosed above. The Corporation typically has available three sources of funding to finance its capital expenditure program: (i) internally generated cash flow from operations, (ii) available cash and proceeds from sale of investments or bank financing if the Corporation's asset base can be used as collateral for bank borrowings, and (iii) the issuance of new equity.

Future development costs total \$30.2 million on a total proved basis and \$72.8 million on a total proved plus probable basis. A breakdown of these amounts is provided below.

Proved		
HRB	1.2 net horizontals plus infrastructure	\$ 21.3 million
Umbach	1.8 net horizontals	\$ 8.9 million
Total		\$30.2 million
Proved Plus Probable Additional		
HRB	2.8 net horizontals plus infrastructure	\$ 49.5 million
Umbach	4.8 net horizontals	\$ 23.3 million
Total		\$72.8 million

In 2012, Storm plans to complete 1.0 gross horizontal well (0.6 net) and drill 1.0 gross vertical well (1.0 net) and 2.0 to 3.0 gross horizontal wells (1.2 to 1.8 net) in the Umbach area of northeast British Columbia.

The Corporation expects to fund its total 2012 capital program with internally generated cash flow plus a limited amount of debt, although quarterly fluctuations in funding levels are expected. The Corporation may also sell marketable securities or properties not core to Storm's business plan.

Oil and Gas Properties

Summarized information about Storm's operations and principal operating areas, properties and operations as at December 31, 2011 is as follows:

Horn River Basin, Northeast British Columbia

Subsequent to the SGR Arrangement, Storm's land position in the HRB totals 135 gross sections at a 100% working interest.

Storm's first horizontal well in the HRB was tied-in in early March 2011 with production from the Muskwa and Otter Park formations amounting to 4,600 Mcf gross raw gas per day for 2011, or 1,600 Mcf per day sales gas net to Storm's then 40% interest (266 Boe/d net to Storm).

As of December 31, 2011, gas production was approximately 3,900 Mcf gross raw gas per day, or 3,430 Mcf per day sales gas, or 570 Boe/d.

Umbach, Northeast British Columbia

Storm's current land holdings at Umbach total 98 gross sections or 70 net sections (53,800 net undeveloped acres). The Corporation, as operator with a 60% working interest, began production in March 2011 from a horizontal well drilled into the Montney formation. Production from this well in 2011 averaged 1,370 Mcf gross raw gas per day, or 724 Mcf per day sales net to Storm's working interest, plus associated condensate and natural gas liquids of 24 Bbls per day (145 Boe/d net to Storm). As at December 31, 2011, production was approximately 1,100 Mcf gross raw gas per day, or 590 Mcf per day sales net to Storm, plus associated condensate and NGL production of 19 Bbls per day (120 Boe/d net to Storm).

Two horizontal wells were tied in during the final quarter of 2011. The first of these wells produced 250 Boe/d in 2011 (net to the Corporation), including 42 Bbls of condensate and NGLs. The second well produced 137 Boe/d in 2011, including 23 Bbls of condensate and NGLs.

In aggregate, the three Umbach wells currently produce 365 Boe/d net to Storm, including 62 Bbls of NGLs.

Red Earth, North Central Alberta

In late January 2011, production began from two non-operated 20% working interest horizontal oil wells at Red Earth, with both wells currently producing approximately 45 Bbls/d of light sweet crude net to the Corporation's interest. Red Earth is not regarded as a core property to Storm; however, the Corporation will remain active in the area as long as there is a near-term opportunity to add high netback production.

Mica, Northeast British Columbia

There are seven producing wells on the Mica property and production amounts to 145 Boe/d with an annual decline rate of 5%. Future drilling and a waterflood application could potentially increase production to 450 Boe/d. The Mica Acquisition, which closed in December 2011, is consistent with the Corporation's intention to invest in projects that offer higher netback potential, either crude oil or natural gas with an associated high-value natural gas liquids stream. Future development capital associated with this activity is estimated to be \$12.6 million.

Ownership of SGR and Bellamont

No amounts of oil and gas reserves or production accruing to the Corporation as a consequence of its 100% equity ownership in SGR and Bellamont are included in any table or related discussion in this Annual Information Form as both acquisitions were completed subsequent to December 31, 2011.

Oil and Gas Wells

The following table summarizes the Corporation's interest as at December 31, 2011 in wells that are producing and non-producing.

	Producing Wells				Non-Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>
Alberta	2.0	0.4	-	-	2.0	1.7	5.0	2.6
British Columbia	7.0	7.0	5.0	2.4	2.0	1.9	18.0	13.4
Totals	9.0	7.4	5.0	2.4	4.0	3.6	23.0	16.0

Properties with No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which the Corporation has an interest and also the number of net acres for which the Corporation's rights to explore, develop or exploit will, absent further action, expire within one year, as at December 31, 2011.

	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Horn River Basin – BC	75,421	30,168	2,101
Umbach – BC	76,747	55,465	6,125
Red Earth – AB	13,127	10,652	6,880
Junior – BC	24,929	24,929	3,375
Mica – BC	1,297	1,168	-
Other – AB	1,120	1,120	-
Other – BC	49,964	24,926	2,635
Total	242,605	148,428	21,116

Notes:

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

Drilling Activity

The following table summarizes the gross and net exploration and development wells in which the Corporation participated during the year ended December 31, 2011.

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	-	-	-	-	-	-
Natural gas wells	4.0	2.2	-	-	4.0	2.2
Service wells	-	-	-	-	-	-
Stratigraphic test wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	4.0	2.2	-	-	4.0	2.2

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 14.0 (9.8 net) wells totalling \$388,400 net (undiscounted) are included in the estimate of future net revenue for the proved developed producing and proved non-producing reserve categories. The present value of this cost is \$136,900 using a 10% discount rate. Abandonment and reclamation costs for future undeveloped drilling locations are not yet included. Storm owns an interest in 41 wells (29.4) net. Based on the InSite Report, over the next three years, Storm's net well abandonment cost is expected to total \$nil.

Tax Horizon

As at December 31, 2011, the Corporation had resource pools and operating losses of approximately \$76.6 million available for deduction against future taxable income. These existing pools, plus pool additions through the Corporation's capital program in 2012, mean that the Corporation does not expect to pay income tax in 2012. However, measurement of losses and tax pools and their availability are subject to audit and reassessment by Canada Revenue Agency, potentially several years later. Depending on levels of production, commodity prices, acquisitions and capital expenditures, Storm will not pay current income taxes until at least year 2015.

Costs Incurred

The following table summarizes the Corporation's gross property acquisition costs, exploration costs and development costs for the year ended December 31, 2011, net of dispositions of properties of \$2 million.

Total (\$M)	Property Acquisition Costs (\$M)			Development Costs
	Proved Properties	Unproved Properties	Exploration Costs	
	15,436	-	508	24,852

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 2012 based on the Corporation's reserves and ownership at December 31, 2011. No amounts have been included in respect of the SGR Arrangement and the Bellamont Arrangement which were completed after December 31, 2011.

2012	Crude Oil (Bbls)	NGL (Bbls)	Natural Gas (Mmcf)
HRB	-	-	489
Umbach	-	37,895	961
Red Earth	15,419	69.5	1.4
Mica	32,884	604.3	101
Total	48,303	38,569	1,552

Net of Royalties – Production by Product

2012	Crude Oil (Bbls)	NGL (Mbbbls)	Natural Gas (Mmcf)
HRB	-	-	455
Umbach	-	31,832	807
Red Earth	10,793	49	1
Mica	29,924	550	92
Total	40,717	32,431	1,355

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:

	2011 Quarter Ended			
	Q4 Dec. 31	Q3 Sept. 30	Q2 ⁽¹⁾ June 30	Q1 March 31
Average Daily Production ⁽¹⁾				
Oil (Bbls/d)	80	58	80	59
Liquids (Bbls/d)	72	20	22	13
Gas (Mcf/d)	3,763	2,595	2,958	1,221
Combined (Boe/d)	779	511	595	276
Average Price Received ⁽¹⁾				
Oil (\$/Bbl)	100.05	92.66	103.20	90.59
Liquids (\$/Bbl)	89.95	81.44	86.53	83.68
Gas (\$/Mcf)	3.35	3.48	3.76	3.64
Combined (\$/Boe)	34.78	31.50	35.74	39.53
Royalties Paid				
Oil (\$/Bbl)	5.94	3.38	5.65	5.17
Liquids (\$/Bbl)	17.31	13.76	13.41	16.13
Gas (\$/Mcf)	0.21	0.05	0.01	0.03
Combined (\$/Boe)	3.22	1.19	1.29	2.01
Operating & Transportation Expenses				
Oil (\$/Bbl)	20.21	32.58	12.39	17.56
Liquids (\$/Bbl)	3.46	3.18	3.44	2.94
Gas (\$/Mcf)	1.75	1.28	1.35	1.40
Combined (\$/Boe)	10.85	10.35	8.47	10.11
Netback Received ⁽²⁾				
Oil (\$/Bbl)	73.90	56.70	85.16	67.86
Liquids (\$/Bbl)	69.18	64.50	69.68	64.61
Gas (\$/Mcf)	1.39	2.15	2.40	2.21
Combined (\$/Boe)	20.71	19.96	25.98	27.41

Notes:

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

SELECTED FINANCIAL INFORMATION

Summary of Operating Results

The following table sets forth selected financial information of the Corporation for the year ended December 31, 2011.

(\$M, except per share amounts)

Funds applied to operations ⁽¹⁾	1,874
Per share - basic	\$0.07
- diluted	\$0.07
Net income (loss)	(3,664)
Per share - basic	\$(0.14)
- diluted	\$(0.14)
Total assets – December 31, 2011	\$109,083
Net debt less marketable securities – December 31, 2011 ⁽²⁾	\$6,333

Notes:

- (1) Funds applied to operations and funds applied to operations per share are non-GAAP measurements that represent cash applied to operating activities before adjustment for net changes in non-cash working capital items. Funds applied to operations per share are calculated on the same basis as earnings per share. It is likely that these non-GAAP measurements may not be comparable to the calculation of similar amounts for other entities. In particular, funds applied to operations are not intended to represent or be equivalent to cash flow from operating activities calculated in accordance with GAAP.
- (2) The Corporation had a working capital deficiency of \$2.2 million at December 31, 2011.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of Storm consists of an unlimited number of Common Shares and an unlimited number of first preferred shares (the “**First Preferred Shares**”), issuable in series. As at March 30, 2012, an aggregate of 61,824,256 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.

DIVIDENDS

The Corporation has not declared or paid any dividends on its Common Shares since the completion of the Plan of Arrangement. 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.

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, 2011 to December 31, 2011.

Month	High (\$)	Low (\$)	Volume
January 2011	4.10	3.86	947,806
February 2011	4.50	3.98	887,086
March 2011	4.80	4.15	443,523
April 2011	5.50	4.51	103,380
May 2011	5.00	4.39	66,300
June 2011	5.25	4.80	78,857
July 2011	5.25	4.71	56,370
August 2011	4.76	3.80	123,079
September 2011	4.25	3.75	485,350
October 2011	3.82	3.41	41,659
November 2011	3.95	3.50	60,871
December 2011	4.00	3.70	73,231

PRIOR SALES

For the year ended December 31, 2011, Storm did not issue any securities of Storm or any convertible securities of Storm to purchase Common Shares. Subsequent to the year ended December 31, 2011, Storm issued the following securities of the Corporation:

Date of Issue/Grant	Number and Designation of Securities	Issue/Exercise Price (\$)
January 12, 2012 ⁽¹⁾	11,761,190 Common Shares	\$3.70
March 23, 2012 ⁽²⁾	6,946,000 Common Shares	\$3.40
March 23, 2012 ⁽³⁾	16,740,096 Common Shares	\$2.37

Notes:

- (1) Issued pursuant to the SGR Arrangement. See "General Development of Business - Subsequent Events to Year Ended 2011".
- (2) Issued pursuant to the Private Placement. See "General Development of Business - Subsequent Events to Year Ended 2011".
- (3) Issued pursuant to the Bellamont Arrangement. See "General Development of Business - Subsequent Events to Year Ended 2011".

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 m³/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 and the issue of such licence requires the approval of the Governor in Council.

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 firm pipeline capacity continues to limit the ability to produce and market natural gas production although pipeline expansions are ongoing. In addition, the prorating 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. Recently, there has been a considerable increase in supply from shale and other tight gas, in part reflecting higher initial productivity from new wells. From 2009 through to 2012, the production of natural gas from these sources, coupled with other factors such as reduced industrial demand, resulted in prices for natural gas being restricted to a range which did not provide an acceptable commercial return. 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 2012, Pacific Rim countries, particularly China, Japan and South Korea, through sovereign oil companies, or representatives of end users, have expressed interest in or committed to invest in, infrastructure projects and exploration and development activities, with a view to securing sources of future supply. These projects have a long lead time, but if consummated, may result in Canada becoming a significant exporter of natural gas to the Pacific Rim, as an additional or successor market to the U.S. It will 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 likely that this will continue to be the case in 2012.

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. 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.

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 tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving 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 and freehold 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 or 11,450 m³ produced, whichever comes first; and 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 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:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to \$100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeast British Columbia;
- *Deep Royalty Credit Program* applies to vertical and horizontal natural gas wells and provides a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 m and horizontal wells with a true vertical depth greater than 2,300 m spud between December 1, 2003 and September 1, 2009. From September 1, 2009 the true vertical depth for qualifying horizontal wells was reduced from 2,300 metres to 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 m and a re-entry date subsequent to December 1, 2003;
- *Deep Discovery Royalty Credit Program* providing the lesser of a three-year royalty holiday or 283,000,000 m³ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 m whose surface locations 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 m³ as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land;
- *Marginal Royalty Reduction Program* providing royalty breaks for low productivity natural gas wells with average monthly production under 25,000 m³ per day during the first 12 production months and average daily production less than 23 m³ for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m³ per day during the first 12 production months and average daily production less than 11.5 m³ (development wells) or 17 m³ (exploratory wildcat wells) for every 100 m of marginal well depth;
- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

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 m³ 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, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded \$120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres.

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 "**NRF**"). 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 transition 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, 2010, 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, 2010. The new well incentive program applied to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provide for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 Bbls or 500 Mmcf of natural gas.

In June 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

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 NRF 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. Alberta Energy has stated that it intends to defer serving reversion notices pending a review in spring 2012.

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 international conventions and national, provincial, and municipal laws and regulations. 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.

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, 2011, the Corporation owned approximately 41.0 gross and 29.4 net wells for which abandonment and reclamation costs are expected to be incurred. As disclosed in the Corporation's audited financial statements for the year ended December 31, 2011, the total amount required to settle the Corporation's future asset retirement obligations, including environmental remediation, is estimated to be \$3.1 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, the 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 February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It required the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorized the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

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 CO₂ equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalents per facility per year for an upstream oil and gas facility; and (iii) 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. 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.

Although the timing and 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 \$20/tonne of CO₂ equivalent increasing to \$30/tonne in 2012. 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 CO₂ equivalents per year to report their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO₂ equivalents per year are required to have their emissions reports verified by a third party. Each facility with a requirement to report were required to submit their first report (for calendar year

2010 emissions) to the British Columbia Ministry of Environment by March 31, 2011. 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

Storm anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Storm does not have, or is unable to increase, revenues or reserves in the future, Storm may have limited ability 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 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 Storm. Moreover, future activities may require Storm to alter its capitalization significantly. The inability of Storm to access

sufficient capital for its operations could have a material adverse effect on Storm's financial condition, results of operations or prospects.

Additional Funding Requirements

Storm's future cash flow may not be sufficient to fund its ongoing activities at all times. From time to time, Storm 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 Storm to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Storm's future revenues decrease as a result of lower oil and natural gas prices or otherwise, it will affect Storm's ability to attract the necessary capital to identify and increase reserves or to maintain its production. If Storm'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 will be available to meet this funding shortfall or available on terms acceptable to Storm.

Capital and Lending Markets

As a result of the general economic uncertainties and in particular 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 generated 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 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 certain marketable securities, potential disposition of which may provide additional funds to support capital programs.

The Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets, including the acquisition of SGR, Bellamont and the Mica Assets, as well as smaller acquisitions and dispositions 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 the Corporation's ability to realize 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. Nevertheless, the Corporation has benefited from the Deep Well Royalty Credit in British Columbia; however, the limited duration of the program and the Corporation's disciplined approach to drilling means that the benefit will apply to a relatively small number of the Corporation's wells. Exploitation of the Bellamont assets will enable the Corporation to access the currently favourable Alberta royalty structure.

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 select 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, 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 affect 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 could result in a reduction of the Corporation's future production revenue and overall value and could result in reserve and ceiling test write-downs. 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. 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 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 flow 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.

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, 2011 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

Storm's success depends in large measure on certain key personnel including Brian Lavergne, Donald G. McLean, Robert S. Tiberio, Daniel J. Fitzgerald and John 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. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Dilution

The Corporation may make future acquisitions or enter into financing or other transactions involving the issuance of securities of Storm 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 to Storm, such failures could have a material adverse effect on the Corporation, its cash flow from operations and its liquidity structure.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, no contracts entered into by Storm during the most recently completed financial year can reasonably be regarded as presently material to Storm. Subsequent to December 31, 2011, Storm completed arrangement agreements with respect to the SGR Arrangement and the Bellamont Arrangement which Storm regards as material to the business of Storm. See “*General Development of Business - Subsequent Events to Year Ended 2011*”.

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 Storm during, or related to, Storm’s most recently completed financial year other than InSite, the independent reserve evaluators, and Ernst & Young LLP, Storm’s auditors. None of the principals of InSite had any registered or beneficial interests, direct or indirect, in any securities or other property of Storm or of Storm’s 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 Storm in accordance with the rules of professional conduct of the Institute of Chartered Accountants of Alberta.

Certain legal matters relating to the business of Storm will be passed upon on Storm’s behalf by McCarthy Tétrault LLP. As at the date hereof, the partners and associates of McCarthy Tétrault LLP as a group beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares.

AUDITORS, TRANSFER AGENT AND REGISTRAR

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

The transfer agent and registrar for the Common Shares of Storm 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 financial statements, and Management’s Discussion and Analysis for the year ended December 31, 2011. Management and auditors’ reports on the financial statements are dated March 1, 2012 and Management’s Discussion and Analysis is dated March 1, 2012. These documents are available on the SEDAR website at www.sedar.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, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, 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, 2011 and reported on to the Company’s management.

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.

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, 2011, prepared between January and February 2012	Canada	-	\$54,504,900	-	\$54,504,900
Totals			-	\$54,504,900	-	\$54,504,900

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, P. Eng"

D.L. Paddock, P.Eng.
Managing Director

March 30, 2012

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, 2011, 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.

"Brian Lavergne"

Brian Lavergne
President and Chief Executive Officer

"Donald G. McLean"

Donald G. McLean
Chief Financial Officer

"Matthew J. Brister"

Matthew J. Brister
Director

"P. Grant Wierzba"

Grant Wierzba
Director and Chairman of the Reserves Committee

March 30, 2012

APPENDIX C

STORM RESOURCES LTD. AUDIT COMMITTEE TERMS OF REFERENCE

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

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

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

- (a) that the Company complies with all applicable laws, regulations, rules, policies and other requirement of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;
- (b) that the accounting principles, significant judgments and disclosures which underlie or are incorporated in the Company's financial statements are appropriate in the prevailing circumstances;
- (c) that the Company's quarterly and annual financial statements are accurate within a reasonable level of materiality and present fairly the Company's financial position and performance in accordance with generally accepted accounting principles; and
- (d) that appropriate information concerning the financial position and performance of the Company is disseminated to the public in a timely manner in accordance with corporate and securities law and with stock exchange regulations.

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

- (i) the Company's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Company's financial transactions;
- (ii) the internal financial controls are regularly assessed for effectiveness and efficiency;
- (iii) the Company's quarterly and annual financial statements are properly prepared by management to comply with International Financial Reporting Standards ("**IFRS**"); and
- (iv) the Company's quarterly and annual financial statements are reported on by an external auditor appointed by the shareholders of the Company.

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

2. **Composition of Committee**

- (a) The Committee shall be appointed annually by the Board and consist of at least three members from among the directors of the Company, each of whom shall be an independent director (as determined under applicable laws). Officers of the Company, who are also directors, may not serve as members of the Audit Committee;
- (b) The Board shall designate the Chairman of the Committee; and
- (c) In the event of a vacancy arising in the Committee or a loss of independence of any member, the Committee will fill the vacancy within six months or by the following annual shareholders' meeting if sooner.

3. **Reliance on Experts**

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

- (a) financial statements of the Company represented to him by an officer of the Company or in a written report of the external auditors to present fairly the financial position of the Company in accordance with IFRS; and
- (b) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

4. **Limitations on Committee's Duties**

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

II. **Audit Committee Terms of Reference**

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

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

A. *Operating Principles*

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

1) **Committee Values**

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

2) **Communications**

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

3) **Financial Literacy**

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

4) **Annual Audit Committee Work Plan**

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

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

5) **Meeting Agenda**

Committee meeting agendas shall be the responsibility of the Chairman of the Committee in consultation with Committee members, senior management and the external auditors.

6) **Committee Expectations and Information Needs**

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

7) **External Resources**

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

8) **In Camera Meetings**

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

9) **Reporting to the Board**

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

10) **Committee Self Assessment**

The Committee shall annually review, discuss and assess its own performance. In addition, the Committee shall periodically review its role and responsibilities.

11) **The External Auditors**

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

B. Operating Procedures

- 1) The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chairman, upon the request of two (2) members of the Committee or at the request of the external auditors.
- 2) A quorum shall be a majority of the members.
- 3) Unless the Committee otherwise specifies, the Secretary (or his or her deputy) of the Company shall act as Secretary of all meetings of the Committee.
- 4) In the absence of the Chairman of the Committee, the members shall appoint an acting Chairman.
- 5) A copy of the minutes of each meeting of the Committee shall be provided to each member of the Committee and to each director of the Company in a timely fashion.

C. Specific Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall:

Financial Reporting

- 1) Review, prior to public release, the Company's annual and quarterly financial statements with management and the external auditors with a view to gaining reasonable assurance that the statements (i) are accurate within reasonable levels of materiality, (ii) complete, (iii) represent fairly the Company's financial position and performance in accordance with IFRS. The Committee shall report thereon to the Board before such financial statements are approved by the Board;
- 2) Receive from the external auditors reports or their review of the annual and quarterly financial statements;
- 3) Receive from management a copy of the representation letter provided to the external auditors and receive from management any additional representations required by the Committee;
- 4) Review, prior to public release, and, if appropriate, recommend approval to the Board, of news releases and reports to shareholders issued by the Company with respect to the Company's annual and quarterly financial statements;
- 5) Review and, if appropriate, recommend approval to the Board of prospectuses, material change disclosures of a financial nature, management discussion and analysis, annual information forms and similar disclosure documents to be issued by the Company; and

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

Accounting Policies

- 1) Review with management and the external auditors the appropriateness of the Company's accounting policies, disclosures, reserves, key estimates and judgements, including changes or variations thereto;
- 2) Obtain reasonable assurance that they are in compliance with IFRS from management and external auditors and report thereon to the Board;
- 3) Review with management and the external auditors the apparent degree of conservatism of the Company's underlying accounting policies, key estimates and judgements and provisions along with quality of financial reporting; and
- 4) Participate, if requested, in the resolution of disagreements, between management and the external auditors.

Risk and Uncertainty

- 1) Acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Company, determine the Company's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:
 - (a) reviewing with management the Company's tolerance for financial risks;
 - (b) reviewing with management its assessment of the significant financial risks facing the Company;
 - (c) reviewing with management the Company's policies and any proposed changes thereto for managing those significant financial risks; and
 - (d) reviewing with management its plans, processes and programs to manage and control such risks.
- 2) Review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;
- 3) Where relevant, review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;
- 4) Review the adequacy of insurance coverage maintained by the Company; and
- 5) Review regularly with management, the external auditors and the Company's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Company and the manner in which these matters have been disclosed in the financial statements.

Financial Controls and Control Deviations

- 1) Review the plans of the external auditors to gain reasonable assurance that the evaluation and testing of applicable internal financial controls is comprehensive, coordinated and cost-effective;
- 2) Receive regular reports from management and the external auditors on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto;
- 3) Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Board, under conditions of confidentiality, concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgment, through existing reporting structures in the Company; and
- 4) Review, and periodically assess the adequacy of controls over financial information disclosed to the public, which is extracted or derived from the Company's financial statements.

Compliance with Laws and Regulations

- 1) Review regular reports from management and others (e.g. external auditors) with respect to the Company's compliance with laws and regulations having a material impact on the financial statements including:
 - (a) tax and financial reporting laws and regulations;
 - (b) legal withholding requirements; and
 - (c) other laws and regulations which expose directors to liability.
- 2) Review the filing status of the Company's tax returns and those of its subsidiaries.

Relationship with External Auditors

- 1) Recommend to the Board the nomination of the external auditors;
- 2) Approve the remuneration and the terms of engagement of the external auditors as set forth in the Engagement Letter;
- 3) Review the performance of the external auditors annually or more frequently as required;
- 4) Receive annually from the external auditors an acknowledgement in writing that the shareholders, as represented by the Board and the Committee, are their primary client;
- 5) Receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non-audit services by the Company;
- 6) Review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditors propose to employ;
- 7) Meet with the external auditors in the absence of management to determine, *inter alia*, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee;

- 8) Establish effective communication processes with management and the Company's external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee; and
- 9) Establish a reporting relationship between the external auditors and the Committee such that the external auditors can bring directly to the Committee matters that, in the judgment of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee as to disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved.

Other Responsibilities

- 1) Approve annually the reasonableness of the expenses of the Chairman of the Board and the Chief Executive Officer;
- 2) After consultation with the Chief Financial Officer and the external auditors, consider at least annually, of the quality and sufficiency of the Company's accounting and financial personnel and other resources;
- 3) Approve in advance non-audit services, including tax advisory and tax compliance services, provided by the external auditors. However, the Committee can establish a threshold amount for fees for non-audit services to be provided by the external auditors without advance approval of the Committee. The nature of such services and the associated cost will be provided to the Committee at the next following meeting;
- 4) Investigate any matters that, in the Committee's discretion, fall within the Committee's duties;
- 5) Perform such other functions as may from time to time be assigned to the Committee by the Board;
- 6) Review and update the Terms of Reference on a regular basis for approval by the Board; and
- 7) The Committee will review disclosures regarding the organization and duties of the Audit Committee to be included in any public document, including quarterly and annual reports to shareholders, information circulars and annual information forms.