

STORM EXPLORATION INC.

RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2008

MARCH 31, 2009

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NOTE REGARDING FORWARD-LOOKING STATEMENTS

All forward-looking statements in this Annual Information Form (“AIF”) are based on assumptions and Storm’s view of future events which reflect information available at the time the assumption was made. Certain statements contained in this AIF constitute forward-looking statements. The use of any of the words “anticipate”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “should”, “believe” and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Management believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included herein should not be unduly relied upon. These statements speak only as of the date hereof or at the date specified in the documents incorporated by reference into this AIF.

In particular, this AIF contains forward-looking statements pertaining to the following:

- oil and natural gas production levels;
- capital expenditure programs;
- the quantity and quality of the oil and natural gas reserves;
- projections of commodity prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through exploration, development and acquisitions; and
- treatment under governmental regulatory regimes including taxation.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors and assumptions set forth below and elsewhere in this AIF, including, but not limited to:

- volatility in market prices for oil, natural gas and natural gas liquids;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, *inter alia*, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- failure to realize the anticipated benefits of acquisitions;
- changes to legislation or regulations to which the company is subject; and
- the other factors discussed under “Risk Factors” herein.

Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this AIF or in documents incorporated by reference or otherwise, and while Storm Exploration Inc. may choose to do so, it accepts no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise except as required by securities legislation.

SELECTED ABBREVIATIONS

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

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
Mmbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
MMBTU	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
WTI	West Texas Intermediate

AECO	Alberta Energy Company's natural gas storage facility located at Suffield, Alberta
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
ARTC	means the Alberta royalty tax credit
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
CCS	carbon capture of storage
GMG	greenhouse gas
MBOE	1,000 barrels of oil equivalent
MMBOE	1,000,000 barrels of oil equivalent
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 6Mcf: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 oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

Gigajoules	MMBTU	0.950
MMBTU	Gigajoules	1.0526

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

CURRENCY OF INFORMATION

The information set out in this AIF is stated as at December 31, 2008 unless otherwise indicated.

THE CORPORATION

Storm Exploration Inc. (“Storm” or the “Corporation”) was continued under the *Canada Business Corporations Act* (the “CBCA”) on October 26, 1999 under the name of Alterna Technologies Group Inc. On June 29, 2004, the Corporation filed Articles of Amendment to change its name to Storm Exploration Inc.

Storm is engaged in the exploration for, and the acquisition, development and production of, oil and natural gas reserves in the provinces of Alberta and British Columbia. The Corporation’s growth is focused on a selective combination of exploratory and development drilling, 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 Parkland/Ft St John area of north eastern British Columbia, Kotcho/Cabin/Junior, also in north eastern British Columbia and the Peace River Area in north western Alberta.

Storm commenced oil and gas operations effective July 1, 2004 as an exploration company emerging from the plan of arrangement (the “Plan of Arrangement”) involving Harvest Energy Trust and Storm Energy Ltd. (“SEM”). Pursuant to the Plan of Arrangement, SEM transferred to Storm oil and gas properties having approximately 900 BOE/D of production and 4,046 MBOE of proved plus probable reserves, together with an undeveloped land inventory of 287,000 net acres. Storm’s production has grown to a current level of approximately 8,500 Boe per day primarily as a result of drilling success in the Parkland/Ft St John area.

Under the Plan of Arrangement the Corporation also received a 26% (now 6%) interest in Storm Ventures International Inc. (“SVI”), a private company involved in the identification and exploitation of unconventional or international oil and gas opportunities. SVI currently operates in the UK sector of the North Sea and in Tunisia. In January 2009, SVI concluded the acquisition of the remaining shares of Silverstone Energy Ltd., a then 33% owned affiliate through which SVI was active in the UK sector of the North Sea. This involved the exchange of 1.67 shares of SVI for each share of Silverstone not already owned by SVI. SVI now has 76.2 MM shares outstanding, 36 million Boe of proved plus probable reserves (as evaluated by Sproule Associates Limited and Paddock Lindstrom & Associates Ltd.) and estimated current production of 2,000 Boe per day primarily from the Victoria gas discovery in the North Sea which is currently producing approximately 12 mmcf per day. The majority of SVI’s activity over the next year is likely to be focused on advancing three major development projects including the Vulcan East discovery in the North Sea, the Remada Sud light oil discovery in Tunisia and the Cosmos fallow discovery offshore Tunisia. In addition to these development projects, SVI has accumulated a land position containing multiple higher impact, larger scale prospects with one being tested in the first half of 2009 at Jenein Centre in Tunisia.

The Corporation has an investment in Storm Gas Resource Corp. (“SGR”) which was incorporated in June 2007 to identify and participate in unconventional natural gas opportunities; initially the Devonian shale resource in the Horn River Basin of north eastern British Columbia. Storm’s initial ownership position was 45%, the remaining shareholders being SVI, also at 45%, and SGR employees at 10%. Storm’s initial investment in SGR at \$1.00 per share was satisfied by a cash contribution of \$833,000 and the transfer of undeveloped lands at a value of \$417,000. During 2008, SGR completed a private equity issue and raised \$38.2 million (net of share issue costs) at a price of \$6.50 per share. Storm invested \$4.9 million to acquire

0.8 million shares as part of this offering. Storm's investment to date in SGR totals \$6.2 million and the ownership position totals 2.05 million shares, representing a 22% ownership interest of SGR. At the end of 2008, SGR's balance sheet showed a cash position of approximately \$30 million and the land position in the Horn River Basin totalled 106 gross sections or 62 net sections. SGR's focus in the short term will be directed towards expanding its Devonian shale land position in the Horn River Basin and testing the productivity of its land position with vertical wells as well as horizontal wells. SGR is identifying other areas with unconventional gas potential where undeveloped land can be acquired at reasonable cost.

Storm conducts its business through Storm Production Partnership (the "Partnership") a general partnership formed pursuant to the laws of Alberta. The partners of the Partnership are Storm and 1318640 Alberta Ltd., an Alberta corporation wholly-owned by Storm.

Storm is a reporting issuer (or the equivalent) in each of the provinces of Canada. On July 2, 2004, the common voting shares (the "Common Shares") of Storm were listed and posted for trading on the Toronto Stock Exchange (the "TSX") under the symbol "SEO".

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

2009 Developments

On March 6, 2009, the Corporation completed a bought deal public offering of 1.85 million Common Shares at a price of \$10.60 per share for total proceeds of \$19.6 million. The proceeds of the offering were used to reduce amounts owing under Storm's credit facilities.

2008 Developments

During 2008, Storm's production growth largely came from drilling 12 horizontal Montney development wells (11.7 net) at the Parkland property in north eastern British Columbia with eight of these being completed and tied in before year end resulting in production at Parkland property increasing from 3,305 Boe per day in January 2008 to 5,500 Boe per day in December 2008. In addition, 10 vertical Montney wells (9.1 net) were drilled and significantly expanded the areal extent of Storm's Montney discovery.

In November, 2008, construction started at a second facility at Parkland which was completed and operational on January 14, 2009. Initial capacity of this facility is 12 Mmcf per day which increased the total capacity at Parkland to 45 Mmcf per day with current gross raw gas throughput being 36 Mmcf per day with net sales being approximately 6,000 Boe per day.

In July 2008, the Corporation participated in a private placement of common shares of SVI in the amount of \$1,250,000 and acquired 200,000 shares. As the Corporation's participation was not pro rata to its existing interest, the Corporation's ownership position in SVI was reduced from 13% to 12%. Subsequently, as described above, SVI issued additional common shares, reducing the Corporation's ownership position to 6%.

Also in July 2008, the Corporation participated in a private placement of common shares in Storm Gas Resource Corp. in the amount of \$4,940,000 and acquired 800,000 shares. The terms of the private placement were such that the Corporation's initial ownership position of 45 % was reduced to 22%.

2007 Developments

On September 6, 2007, the Corporation completed a bought deal private placement of 1.4 million flow-through Common Shares at a price of \$10.75 per share for total proceeds of \$15.1 million. The terms of the issue require that the Corporation renounce to subscribers Canadian Exploration Expense (“CEE”) in a like amount to be incurred prior to December 31, 2008, which renunciation occurred prior to the deadline. During the year the Corporation issued 87,000 Common Shares upon the exercise of stock options and 131,000 Common Shares under a performance warrant plan. The performance warrant plan has terminated and no further shares are issuable thereunder.

On May 23, 2007, the Corporation announced the acquisition of the remaining 25% working interest it did not already own in certain lands in the Parkland area of north eastern British Columbia. The cost of the acquisition was \$25.5 million plus the Corporation’s working interest in six producing oil wells at Red Earth. The Corporation acquired 482 MBOE proved and 571 MBOE proved and probable reserves (net of the Red Earth disposition). Undeveloped lands acquired totalled 5,675 net acres.

On August 14, 2007, the Corporation announced the discovery of natural gas in the Montney formation in the Parkland area. This discovery resulted in the Corporation focusing its efforts on exploitation of the resource thus identified and on expanding its land position in the area. Exploitation activities at Parkland accounted for most of the Corporation’s capital expenditures in the second half of 2007, including the drilling and bringing on stream of horizontal wells drilled into the Montney formation.

2006 Developments

On June 1, 2006, the Corporation completed a bought deal private placement of 1.9 million flow-through Common Shares at a price of \$8.20 per Common Share, for gross proceeds of \$15.58 million. The terms of the share issue required the Corporation to renounce to subscribers Canadian Exploration Expense (“CEE”) in the amount of \$15.58 million, to be incurred prior to December 31, 2007, which renunciation occurred prior to the deadline. Other shares issued in the year resulted from the exercise of stock options, performance warrants and share purchase warrants.

On June 15, 2006, the Corporation completed the acquisition, effective May 1, 2006, of certain oil and natural gas properties within its Peace River Arch and Cabin/Kotcho/Junior core areas for a total purchase price of approximately \$40 million. See “Significant Acquisitions”. In August, the Corporation sold certain oil and gas properties in the Brazeau Pembina areas of central Alberta for proceeds of approximately \$9,400,000.

During December 2006, SVI completed the private placement of 8.5 million common shares at \$5 per share, for gross proceeds to SVI of \$43 million. Storm purchased 200,000 SVI common shares pursuant to the private placement, increasing its investment in SVI by \$1,000,000; however the Corporation’s percentage ownership in SVI fell from 16% to 13% (or 4.3 million shares) as a result of the private placement.

Significant Acquisitions

On June 8, 2007, the Corporation completed an acquisition, which added production of 465 Boe per day, and increased Storm’s working interest to 100% in certain lands in the Parkland area of north eastern British Columbia. The cost of the acquisition was \$25.5 million plus the Corporation’s working interest in six oil wells at Red Earth, producing 110 net barrels of oil per day. Undeveloped lands acquired totalled 5,675 net acres.

On June 15, 2006, the Corporation completed the acquisition, effective May 1, 2006, of certain oil and natural gas properties within its Peace River Arch and Cabin/Kotcho/Junior core areas for a total purchase price of approximately \$40 million. The acquisition was financed through an expansion of the Corporation’s existing

credit facilities. Production from the acquired properties was approximately 1,000 Boe per day at the time of acquisition, of which 75% was natural gas. The Peace River Arch properties produced 600 Boe per day of this total, with the Cabin/Kotcho/Junior properties producing the remaining 400 Boe per day. Undeveloped land totalling 13,000 net acres was included in the acquisition, with \$2.1 million of the acquisition cost being allocated toward the purchase of this land. At the time of acquisition, the Corporation had identified 15 development opportunities on the acquired assets including ten drilling locations and five workovers.

NARRATIVE DESCRIPTION OF BUSINESS

General

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, and the generation of its own prospects, operatorship of its assets wherever possible and maintenance of high working interests.

The Corporation expects 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 approved 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 levels within corporate guidelines. Hedging may be used as part of a debt management program.

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 have prevailed in the first quarter of 2009 and thus enhance its competitive position.

Competitive Conditions

The Corporation actively competes for reserve acquisitions, exploration leases, licences and concessions 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 and other entities, such as royalty trusts.

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 and to consummate commercially attractive transactions in a highly competitive environment.

Cyclical Nature of Business

Storm's properties generally, with the exception of the Horn River Basin and Kotcho/Cabin/Junior in north eastern British Columbia, provide year round access, enabling drilling and workover activities to continue throughout the year. The majority of Storm's revenue comes from the sale of natural gas (approximately 86% of total revenue in 2008) with natural gas pricing being dependent on storage levels and demand which peaks during the cold winter months. This can result in significant price volatility which Storm attempts to mitigate through growth in production volumes and by keeping debt at less than 1.5 times the current year's estimated cash flow.

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

Renegotiation or Termination of Contracts

It is not expected that the Corporation's business will be affected in the current financial year by the renegotiation or termination of contracts or sub-contracts which are material to the Corporation's business.

Employees

As of December 31, 2008, the Corporation had 27 full-time employees, and 7 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:

<u>Name and Municipality of Residence</u>	<u>Position Held</u>	<u>Date First Elected or Appointed as Director⁽⁴⁾</u>
Stuart G. Clark ⁽¹⁾ Calgary, Alberta	Chairman and Director	June 29, 2004
Brian Lavergne Calgary, Alberta	President, Chief Executive Officer and Director	September 20, 2004
Donald G. McLean Calgary, Alberta	Vice President, Finance and Chief Financial Officer	

<u>Name and Municipality of Residence</u>	<u>Position Held</u>	<u>Date First Elected or Appointed as Director⁽⁴⁾</u>
Robert S. Tiberio Calgary, Alberta	Chief Operating Officer	
Harry Ediger Calgary, Alberta	Vice President, Land	
Eric Blakely Calgary, Alberta	Vice President, Exploration	
John J. Devlin Calgary, Alberta	Controller	
Gregory G. Turnbull ⁽²⁾ Calgary, Alberta	Corporate Secretary and Director	May 13, 2005
Matthew J. Brister ⁽¹⁾⁽³⁾ London, U.K.	Director	June 29, 2004
John A. Brussa ⁽²⁾ Calgary, Alberta	Director	June 29, 2004
Henry R. Lawrie ⁽¹⁾⁽³⁾ Calgary, Alberta	Director	June 29, 2004
Mark A. Butler ⁽²⁾ Calgary, Alberta	Director	May 19, 2004
Grant Wierzba ⁽³⁾ Calgary, Alberta	Director	May 13, 2005

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 Voting 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 11,622,230 Common Voting Shares of Storm and 140,625 Common Non-Voting Shares of Storm.

Each of Messrs. Lavergne, McLean, Ediger, Tiberio, Blakely and Devlin devotes his full time and attention to the business and affairs of Storm. The remaining directors and officers 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 last five years is set forth below.

Stuart G. Clark, Chairman and Director

Mr. Clark has a Bachelor of Commerce (Honours) from the University of Manitoba. Mr. Clark was a Director of Storm Energy Ltd. ("SEM") from August, 2002 to June, 2004. Prior to August, 2002 Mr. Clark was a Director and Vice President, Finance and Chief Financial Officer of Storm Energy Inc. ("SEI") from

November, 1998 to November 8, 2001 when he assumed the office of Executive Director until August, 2002. From January, 1986 to July, 1998, Mr. Clark was employed by Pinnacle Resources Ltd. (“Pinnacle”) in positions of increasing responsibility, the last being Executive Vice President and Chief Financial Officer. Mr. Clark was a director of Pinnacle from January, 1986 to July, 1998 and a director of Quadron Resources Ltd., a publicly traded oil and gas company which was listed on the TSX prior to its acquisition by HCO Energy Ltd. in June, 1995. From April, 1989 to May, 1994, Mr. Clark was a director of Avid Oil and Gas Ltd., a publicly traded oil and gas company which was listed on the TSX and the TSX Venture Exchange prior to its acquisition by Husky Energy Ltd. in July, 2001. Mr. Clark is a director of Rock Energy Inc. Mr. Clark was appointed Chairman of the Corporation on May 9, 2008.

Brian Lavergne, President, Chief Executive Officer and Director

Mr. Lavergne has a Bachelor of Science in Mechanical Engineering from the University of Alberta (1989) and is a registered Professional Engineer in the Province of Alberta. Mr. Lavergne has been the President and Chief Executive Officer of Storm since completion of the Plan of Arrangement. Mr. Lavergne was Vice President, Production of SEM from August, 2002 until June, 2003, when he was appointed Chief Operating Officer until June 2004. From December, 1998 until August 2002, Mr. Lavergne was employed with SEI, his last position being Vice President, Production. From February, 1994 to December, 1998, Mr. Lavergne was employed by Renaissance Energy Ltd. in positions of increasing responsibility including Exploitation Manager and Operations District Manager.

Donald G. McLean, Vice President, Finance, Chief Financial Officer

Mr. McLean has been the Chief Financial Officer of the Corporation since completion of the Plan of Arrangement. Mr. McLean was the Chief Financial Officer of SEM from August, 2002 to June, 2004. Mr. McLean was the Chief Financial Officer of SEI from September, 2001 to August, 2002. Mr. McLean is a member of the Institute of Chartered Accountants of Alberta. Mr. McLean was a director of Pinnacle from 1991 to 1998. From 1991 to 2001, Mr. McLean was Chief Financial Officer and director of a number of public and private companies. Prior to 1991, Mr. McLean was a partner of Deloitte & Touche LLP, an accounting firm.

Robert S. Tiberio, Chief Operating Officer

Mr. Tiberio has been the Chief Operating Officer of the Corporation since completion of the Plan of Arrangement. Mr. Tiberio was appointed Vice President of Production of SEM in June, 2003 and held that position until June, 2004. Prior to Mr. Tiberio’s appointment as Vice President of Production, he was a senior Exploitation Engineer with SEM. Prior thereto, Mr. Tiberio spent 10 years with Renaissance Energy Ltd. and Husky Energy in positions of increasing responsibility, ultimately as General Manager of Southern Alberta and Saskatchewan.

Harry Ediger, Vice President, Land

Mr. Ediger has a Bachelor of Arts in Economics from the University of Western Ontario, a Bachelor of Commerce (Honours) from the University of Windsor and is a member of the Canadian Association of Petroleum Landmen. Mr. Ediger has been the Vice President, Land of the Corporation since completion of the Plan of Arrangement. Prior thereto, Mr. Ediger was the Vice President, Land of SEM from August, 2002 to June, 2004. From May, 1999 to August, 2002, Mr. Ediger was the Vice President, Land of SEI. From August, 1987, to March, 1997, Mr. Ediger was employed by Cimarron Petroleum Ltd. in positions of increasing responsibility and from November, 1994 until March, 1997, held the position of Vice President, Land. From April, 1997 to May, 1999, Mr. Ediger was a self-employed consultant. Mr. Ediger was a co-founder of Moxie Petroleum Ltd., a publicly traded oil and gas company which was listed on the TSX Venture Exchange.

Eric C. Blakely, Vice President, Exploration

Mr. Blakely graduated from the University of Calgary in 1983 with a BSc Honours Geology and a geophysics minor. Mr. Blakely has been the Vice President, Exploration of the Corporation since completion of the Plan of Arrangement. Mr. Blakely is a member of Canadian Society of Exploration Geophysicists. He was Exploration Manager of SEM, a position he held in the company and its predecessors since October, 1998. For several years prior to that Mr. Blakely held positions as Chief Geophysicist at Startech Energy Inc. and Pinnacle Resources Ltd..

John J. Devlin, Controller

Mr. Devlin joined the Corporation in February, 2005. He has a B. Comm. (1979) from Concordia University. From 1998 until February, 2005, Mr. Devlin was a self employed financial consultant. Prior thereto, Mr. Devlin was the Treasurer of Pinnacle.

Gregory G. Turnbull, Director and Corporate Secretary

Mr Turnbull is the Regional Managing Partner of the Calgary office of McCarthy Téroult LLP, which he joined in July 2002 following his previous position as partner of Donahue LLP, which he joined in 2001. From 1987 to 2001 Mr. Turnbull was a partner of Gowlings LLP and predecessor firms. Mr. Turnbull was a director of SEM and SEI.

Mr. Turnbull is currently a director of Crescent Point Energy Trust, Storm Exploration Inc., Heritage Oil Limited, Seaview Energy Inc., BNP Resources Inc., Action Energy Inc. and Ammonite Energy Inc., all publicly traded entities listed on the TSX or TSX Venture Exchange. Mr. Turnbull is also currently a director of a number of private companies.

Throughout his career, he has served as an officer or director of Baytex Energy Ltd., Barrington Petroleum Ltd., Castle Rock Petroleum., Flagship Energy Inc., Hawk Oil Inc., Hawk Energy Inc., Kensington Energy Ltd., Lexxor Energy Inc., Newquest Energy Inc., Mannville Oil & Gas Ltd., Petrostar Petroleum Inc., Pinnacle Resources Ltd., Quadron Resources Ltd., Quintex Energy Ltd., Rally Energy Ltd., ResoQuest Resources Ltd., Seventh Energy Ltd., Tri-Ex Oil & Gas Ltd., Trigas Exploration Ltd., Trimox Energy Inc., Twin Energy Ltd., and Westward Energy Inc.

Matthew J. Brister, Director

Mr. Brister has a Bachelor of Science in Geology from the University of Calgary and is a registered Professional Geologist in the Province of Alberta. Mr. Brister was the Chairman of the Corporation from completion of the Plan of Arrangement until May 9, 2008. Mr. Brister was the President and Chief Executive Officer of SEM from August, 2002 to June, 2004. From November, 1998 to August, 2002, Mr. Brister was the President and Chief Executive Officer of SEI. From May, 1987 to July, 1998, Mr. Brister was employed by Pinnacle in positions of increasing responsibility and from January, 1994 to July, 1998 was President and Chief Executive Officer thereof. Pinnacle was a publicly traded oil and gas company listed on the TSX and the Montreal Exchange prior to its acquisition by Renaissance Energy Ltd. in July, 1998. Mr. Brister is the Chief Executive Officer and a director of SVI and is also a director of SGR.

John A. Brussa, Director

Mr. Brussa is a partner in the Calgary-based law firm of Burnet, Duckworth & Palmer LLP specializing in the area of taxation. Mr. Brussa is a past governor of the Canadian Tax Foundation and is a director or trustee of a number of charitable and non-profit organizations. He is a director of the following publicly traded companies: Baytex Energy Ltd. (Baytex Energy Trust), BlackWatch Energy Services Corp., Cirrus Energy

Corporation, Crew Energy Inc., Deans Knight Income Corporation, Divestco Inc., Enseco Energy Services Corp., Galleon Energy Inc., Harvest Operations Corp. (Harvest Energy Trust), Highpine Oil & Gas Limited, Monterey Exploration Ltd. North American Energy Partners Inc., Ontario Energy Savings Corp. (Energy Savings Income Fund), Orleans Energy Ltd., Penn West Petroleum Ltd. (Penn West Energy Trust), Progress Energy Resources Corp. (formerly ProEx Energy Ltd.), Trafalgar Energy Ltd. and Yoho Resources Inc.

P. Grant Wierzba, Director

Mr. Wierzba has a Bachelor of Sciences in Engineering from the University of Alberta and is a registered professional engineer in the Province of Alberta. Mr. Wierzba was Vice President Operations and Chief Operating Officer of SEM from August 2002 until June 2003. From November 1998 until August 2002 he held the same position at SEI. From March 1996 until July 1998, Mr. Wierzba was employed by Pinnacle Resources Ltd. in positions of increasing responsibility, the last being Senior Vice President and Chief Operating Officer and was also a director of the company. From 1980 until February 1996 Mr. Wierzba was employed by Renaissance Energy Ltd. in positions of increasing responsibility, his final role being Senior Vice President, Operations.

Henry R. Lawrie, Director

Mr. Lawrie is a Fellow of the Institute of Chartered Accountants of Alberta. Mr. Lawrie had a 40 year career with PricewaterhouseCoopers LLP and predecessor firms, serving in Calgary, Dallas and Midland, Texas, and Toronto. He was a member of the firm's Policy Board and was managing partner of the firm's Calgary office and co-chaired the firm's Oil and Gas specialty group. He also chaired the Alberta Securities Commission Oil and Gas Securities Taskforce and the Canadian Institute of Chartered Accountants Oil and Gas Full Cost Accounting Taskforce. Mr. Lawrie has served as Chief Accountant of the Alberta Securities Commission, and he is currently a director of Berens Energy Ltd., Bow Valley Energy Ltd., CanElson Drilling Inc. and Delphi Energy Corp.

Mark A. Butler, Director

Mr. Butler is a business consultant and from June 2005 until December 2007 was President of WestPac LNG Corporation, a private company. He was Chief Operating Officer of the Corporation until June 2004 and previously was General Counsel and Vice-President Commercial Transactions, with responsibility for product licensing and intellectual property management. Mr. Butler holds a Bachelor of Law degree from the University of Saskatchewan and a Masters of Business Administration from the University of Calgary.

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 AIF 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) or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. John A. Brussa, a director of the Corporation, was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses and the creation of two public corporations: Imperial Metals Corporation and IEI Energy Inc. (later Rider Resources Ltd.). The plan of arrangement was completed in April 2002.

Mr. Gregory G. Turnbull, a director of the Corporation, was a director of Mobilift Inc., a corporation engaged in the development, system integration and commercialization of innovative fall prevention technology. Mobilift Inc. was placed into receivership in September, 2001 by its major creditor after Mr. Turnbull left the board in August 2001.

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:

- (d) 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
- (e) 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 of Storm 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 CBCA, directors who have an interest in a proposed transaction upon which the board of directors is voting are required to disclose their interests and refrain from voting on the transaction.

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

Mr. Gregory G. Turnbull, a director of Storm, is a partner of McCarthy Tétrault LLP, a law firm that provides legal services to Storm. The board of directors of Storm 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 of Storm 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 communications among the board of directors of Storm, 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 Henry Lawrie (Chairman), Stuart Clark and Matthew 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, 2008 were \$75,000

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, 2008 were \$31,500

Tax Fees

The aggregate fees billed by the Corporation's external auditor for taxation services including tax compliance, tax advice and tax planning in the fiscal year ended December 31, 2008 were \$9,500

All Other Fees

Fees for additional advice were \$1,000

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”), Paddock Lindstrom & Associates Ltd. (“Paddock”) prepared a report (the “Paddock Report”) dated January 12, 2009. The Paddock Report evaluated, as at December 31, 2008, Storm's crude oil, NGL and natural gas reserves. The Paddock December 31, 2008 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 Paddock Report based on constant and forecast price and cost assumptions. The tables summarize the data contained in the Paddock Report and as a result may contain slightly different numbers than the Paddock 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 Paddock. 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 Paddock 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 Paddock Report is based on certain factual data supplied by the Corporation and Paddock'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 Paddock) were supplied by the Corporation to Paddock and accepted without any further investigation. Paddock 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 (Mbbls)	Sales Gas (Mmcf)	Natural Gas Liquids (Mbbls)	6:1 Oil Equivalent (Mboe)	Light Crude Oil (Mbbls)	Sales Gas (Mmcf)	Natural Gas Liquids (Mbbls)	6:1 Oil Equivalent (MBOE)
Proved								
Developed Producing	483	59,525	1,200	11,604	397	46,093	941	9,020
Developed Non-Producing	-	5,135	121	977	-	3,919	93	746
Undeveloped	355	69,798	1,815	13,803	257	51,112	1,371	10,147
Total Proved	838	134,458	3,136	26,384	654	101,124	2,405	19,913
Probable	418	79,385	1,869	15,518	293	60,830	1,473	11,904
Total Proved plus Probable	1,256	213,843	5,005	41,902	947	161,954	3,878	31,817

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

	Before Future Income Tax and Discounted at				
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)
Proved					
Developed Producing	437,118	327,876	268,956	231,185	204,471
Developed Non-Producing	38,433	28,401	22,739	19,108	16,567
Undeveloped	472,847	303,568	212,638	156,398	118,296
Total Proved	948,398	659,845	504,333	406,691	339,334
Probable	668,487	378,937	251,139	180,483	135,992
Total Proved plus Probable	1,616,885	1,038,782	755,472	587,174	475,326

	After Future Income Tax and Discounted at				
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)
Proved					
Developed Producing	370,929	279,984	230,280	198,172	175,356
Developed Non-Producing	27,739	20,366	16,207	13,544	11,683
Undeveloped	344,503	217,123	148,274	105,550	76,585
Total Proved	743,171	517,473	394,761	317,266	263,624
Probable	488,884	274,866	180,154	127,780	94,861
Total Proved plus Probable	1,232,055	792,339	574,915	445,046	358,485

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\$)	Future Income Tax (M\$)	Future Net Revenue After Income Tax (M\$)
Total Proved	1,758,191	413,703	250,743	140,279	5,068	948,398	205,227	743,171
Total Proved plus Probable	2,933,277	677,218	413,731	218,833	6,610	1,616,885	384,830	1,232,055

Future Net Revenue by Production Group

		Future Net Revenue Before Income Taxes (Discounted at 10%)	Unit Value (\$/Mcf) (\$/Bbl)
		(M\$)	
Proved	Light and Medium Crude Oil	23,032	\$27.49/Bbl
	Heavy Crude Oil	-	-
	Natural Gas	481,301	\$3.59/Mcf
	Total	504,333	
Proved Plus Probable	Light and Medium Crude Oil	31,764	\$25.29/Bbl
	Heavy Crude Oil	-	-
	Natural Gas	723,708	\$3.39/Mcf
	Total	755,472	

Future net revenues from natural gas exclude solution gas but do include the value of natural gas liquids. Unit values above are after royalties and operating costs.

Notes and Definitions

In the tables set forth above in “Disclosure of Reserves Data” and elsewhere in this AIF, 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 Paddock Report (as defined herein) in accordance with NI 51-101 and this AIF, 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 and
 - (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). 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

Paddock employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2008 in estimating the Corporation’s reserves data using forecast prices and costs.

Year	Natural Gas		Crude Oil		Natural Gas Liquids		Inflation Rate (%/yr)	CDN/US Exchange Rate (\$US/\$Cdn)
	Henry Hub (\$US/MMBTU)	AECO-C Spot (\$Cdn/MMBTU)	WTI @ Cushing (\$US/Bbl)	EDM Ref Price (\$Cdn/Bbl)	Butane (\$Cdn/Bbl)	Propane (\$Cdn/Bbl)		
2009	6.75	7.24	60.00	70.18	56.14	42.11	2.0	0.84
2010	7.50	7.90	67.50	77.21	61.77	46.33	2.0	0.86
2011	8.00	8.26	75.00	83.93	67.14	50.36	2.0	0.88
2012	8.50	8.60	82.50	90.34	72.27	54.20	2.0	0.90
2013	9.00	9.13	90.00	98.65	78.92	59.19	2.0	0.90
2014	9.30	9.45	91.80	100.62	80.50	60.37	2.0	0.90
2015	9.49	9.64	93.64	102.63	82.11	61.58	2.0	0.90
2016	9.68	9.83	95.51	104.68	83.75	62.81	2.0	0.90
2017	9.87	10.03	97.42	106.78	85.42	64.07	2.0	0.90
2018	10.07	10.23	99.37	108.91	87.13	65.35	2.0	0.90
2019	10.27	10.43	101.35	111.09	88.87	66.66	2.0	0.90
2020	10.47	10.64	103.38	113.31	90.65	67.99	2.0	0.90
Thereafter +2% per annum								

The weighted average realized sales prices including hedging for the year ended December 31, 2008 were \$8.72 Mcf for natural gas, \$98.06 Bbl for crude oil and \$83.97 Bbl for NGLs.

Reconciliations of Changes in Reserves

Reserves Reconciliation

The following table sets forth reconciliations of the Corporation's gross and net reserves comprising total proved, total probable and total proved plus probable reserves as at December 31, 2008 against such reserves as at December 31, 2007 based on forecast price and cost assumptions.

Gross Reserves

Factors	Light Crude Oil (Mbbbls)			NGLs (Mbbbls)			Sales Gas (Mmcf)			6:1 Oil Equivalent (MBOE)		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
December 31, 2007	906	427	1,333	1,172	867	2,039	63,105	39,519	102,624	12,596	7,880	20,476
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Revisions	(25)	(39)	(64)	(94)	(163)	(257)	(4,021)	(6,936)	(10,957)	(783)	(1,358)	(2,141)
Discoveries	2	(1)	1	8	(5)	3	341	(219)	122	67	(43)	24
Extensions	36	32	68	2,345	1,176	3,521	89,073	47,257	136,330	17,221	9,085	26,306
Dispositions	(5)	(1)	(6)	(19)	(6)	(25)	(831)	(236)	(1,067)	(163)	(46)	(209)
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production ⁽¹⁾	(76)	-	(76)	(276)	-	(276)	(13,209)	-	(13,209)	(2,554)	-	(2,554)
December 31, 2008	838	418	1,256	3,136	1,869	5,005	134,458	79,385	213,843	26,384	15,518	41,902

(1) For purposes of this reconciliation, 2008 condensate production has been grouped with NGL production

Net downward revisions to prior year reserves totaled 6.3% on a total proved basis and 10.5% on a proved plus probable basis. Poorer than expected performance at wells producing from the Halfway and Doig formations at Parkland accounted for the majority of the revision. Approximately 25% of this was the result of new, high rate Montney horizontal wells elevating gathering system pressures, which resulted in the reduction of production from Halfway and Doig wells. The remainder was due to a combination of water encroachment and reservoir size being smaller than predicted. Reserves lost as a result of higher gathering system pressures are expected to be recovered as gathering system pressures have decreased with the completion of the second Parkland facility (additional compression) and with the twinning of part of the gathering system in late 2008.

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 impacting 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 Paddock, 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, the subjective decisions, new geological or production information and a changing 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)
2009	82,139	89,848
2010	58,140	72,055
2011	-	56,930
2012	-	-
2013	-	-
2014	-	-
2015	-	-
2016	-	-
Remaining Years	-	-
Total Undiscounted	140,279	218,833
Total Discounted at 10% per year	128,711	192,983

The Corporation estimates that its internally generated cash flow plus unused capacity on its bank credit facility 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; internally generated cash flow from operations, debt financing and new equity.

Future development costs total \$140 million on a total proved basis and \$219 million on a total proved plus probable basis. A breakdown of these amounts is provided below:

	Total Proved	Total Proved plus Probable
Development of Montney discovery at Parkland	\$114 million 20 horizontal wells	\$182 million 32 horizontal wells
Completion and expansion of 2nd Parkland facility	\$5.5 million to complete \$7.5 million to expand to 25 mmcf/d capacity	\$5.5 million to complete \$9 million expand to 40 mmcf/d capacity
Other	\$13 million	\$22 million
	\$140 million	\$219 million

Storm plans to drill seven of the proved undeveloped horizontal Montney gas wells in 2009.

The Corporation expects to fund its total 2009 capital program with internally generated cash flow plus a limited amount of debt although quarterly fluctuations in funding levels are expected. Generally the Corporation's objective is to maintain its debt to cash flow ratio to no greater than approximately 1.5 times current year's estimated cash flows.

Oil and Gas Properties

The following is a description of the oil and natural gas properties, plants, facilities and installations in which the Corporation has an interest and that are material to its operations and activities. The production numbers stated refer to the Corporation's working interest share before deduction of Crown and freehold royalties.

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

Parkland/Fort St. John Area, North Eastern British Columbia

This area includes the Corporation's Montney discovery and is the largest of Storm's core areas, with net production averaging 5,592 Boe per day in the fourth quarter. Average production in 2008 was 4,219 Boe per day, an increase of 63% from average 2007 production of 2,592 Boe per day. Current production is approximately 6,000 Boe per day with approximately 500 Boe per day shut-in to maximize netbacks from the area.

During 2008, 12 horizontal Montney development wells (11.7 net) and ten vertical Montney delineation wells (9.1 net) were drilled.

Development of the Montney discovery continues to progress as expected. Storm is currently producing 27 Mmcf per day of gross raw gas from 11 horizontal Montney gas wells plus 3 Mmcf per day of gross raw gas from 10 Montney vertical wells. Two more horizontal wells drilled late in 2008 were completed, tested, pipeline connected, and came on production before the end of March 2009. First year rates from producing horizontal wells are averaging approximately 2.2 Mmcf per day of raw gas which represents 400 Boe per day of sales per well.

Grand Prairie Area, North Western Alberta

Production from this area averaged 1,706 Boe per day in the fourth quarter of 2008 and production in 2008 averaged 1,816 Boe per day, which is a decline of 11% from average 2007 production of 2,052 Boe per day. Current production is approximately 1,600 Boe per day.

During 2008, one standing well (1.0 net) was recompleted and tied in and is currently producing 50 BOE per day. Despite the lack of activity, declines continue to moderate in this area which is indicative of the higher quality nature of this more mature asset.

Cabin-Kotcho-Junior Area, North Eastern British Columbia

Net production from this area averaged 807 Boe per day in the fourth quarter of 2008 while average production of 884 Boe per day during 2008 represents a 12% decline from average production of 1,010 Boe per day in the year earlier period. Current production is approximately 800 Boe per day. There are five producing wells and all produce from the Slave Point formation which is characterized as having a strong underlying aquifer meaning that produced water rates increase over the life of a well and can be very high late in a well's life.

There was no drilling in this area during 2008.

Since early 2008, Storm has jointly acquired 43 gross sections of undeveloped land in the Horn River Basin at a 40% working interest (8,940 net acres) prospective for Devonian shale gas. This land position was acquired at an average cost of \$500 per acre. These lands were purchased in partnership with Storm Gas Resource Corp. ('SGR') which owns the remaining 60% working interest. Combined with Storm's 22% ownership position in SGR, Storm's exposure to this unconventional shale gas play is approximately 53%. The two vertical test wells being drilled this winter are part of a central project area which encompasses 25 gross sections (10.0 net) containing an estimated 1.9 Tcf of Discovered Petroleum Initially in Place (internal estimate by Storm and SGR) which is based on average gross pay of 80 metres in the Muskwa and Otter Park shales. The Klua/Evie shale was not included in this estimate because less information is available regarding the productivity of this shale in the area. The core from one of this winter's test wells should also provide information on the reservoir characteristics of the shales (porosity, total organic content, thermal maturity, gas content scf/ton) which will be used to verify the estimate of Discovered Petroleum Initially in Place. The economic potential associated with exploiting these shales is not expected to be known until after several horizontal wells have been drilled, providing longer term production data which will facilitate an estimate of potential full-cycle capital costs as well as an estimate of the expected recoverable reserves. This is likely at least two to three years away, making this an early stage project with a high level of associated risk.

Surmont Oil Sands Lease, Alberta

An evaluation of the estimated bitumen contingent resource contained in the McMurray formation on Storm's 3,840 acres (6 sections) of oil sands leases was prepared by McDaniel & Associates Consultants Ltd. effective July 1, 2008. The best case estimate of discovered bitumen resource (defined as bitumen in place exploitable using a Steam-Assisted-Gravity Drainage or SAGD process) is 312 million barrels with the best estimate of contingent bitumen resources recoverable using a SAGD process being 113 million barrels.

In 2008, Storm drilled seven oil sands evaluation wells (7.0 net) to further evaluate and expand estimated bitumen in place. Four were drilled in January 2008 and three more in December 2008. The three wells drilled in December 2008 encountered average net bitumen pay of 22 metres based on log analysis by Storm's technical staff and were not included in the contingent resource evaluation completed by

McDaniel & Associates Consultants Ltd. Storm has no plans at present to initiate development of this resource and no assurance can be provided that this resource will ever be exploited with a conventional SAGD project

Oil and Gas Wells

The following table summarizes the Corporation's interest as at December 31, 2008 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	38.0	21.8	50.0	21.8	23.0	13.8	46.0	23.5
British Columbia	2.0	1.0	46.0	41.3	2.0	1.3	41.0	28.7
Totals	40.0	22.8	96.0	63.1	25.0	15.1	87.0	52.2

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 of December 31, 2008		
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Fort St. John/Parkland – BC	70,267	53,500	-
Kotcho/Cabin/Junior – BC	67,044	45,236	-
Grand Prairie Area – AB	29,766	20,177	1,212
Other	108,022	70,612	13,507
Total	275,099	189,525	14,719

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, 2008.

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	-	-	-	-	-	-
Natural gas wells	21.0	19.78	-	-	21.0	19.78
Test wells	-	-	7.0	7.0	7.0	7.0
Dry holes	-	-	1.0	1.0	1.0	1.0
Total	21.0	19.78	8.0	8.0	29.0	27.78

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 146 (100 net) wells totalling \$3.6 million 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 \$1.3 million using a 10% discount rate. Abandonment and reclamation costs for future undeveloped drilling locations are not yet included. Storm owns an interest in 248 wells (153.2 net). Based on the Paddock Report, over the next three years,

Storm's net well abandonment cost is expected to total \$281,000. Storm's total undiscounted net cost to abandon and reclaim all wells, facilities and pipelines (net of salvage) is expected to be \$6.6 million.

Tax Horizon

The Corporation has resource pools of approximately \$202 million available for deduction against future taxable income. As at December 31, 2008 the Corporation also has a capital loss in the amount of \$10 million, available for application against future capital gains. As a result the Corporation does not expect to pay income tax in 2009. However, measurement of losses and tax pools and their availability, are subject to audit and reassessment by Canada Revenue Agency, potentially several years later.

Costs Incurred

The following table summarizes the Corporation's property acquisition costs, exploration costs and development costs for the year ended December 31, 2008, net of dispositions of proved properties of \$5.0 million.

Total (M\$)	Property Acquisition Costs (\$000)			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
	(4,268)	7,634	72,836	18,762

Production Estimates

Gross – Production by Product

The following table discloses for each product type the total volume of production estimated by Paddock on a proved plus probable basis, for 2009.

2009	Crude Oil ⁽¹⁾ (Mbbls)	NGL (Mmbls)	Natural Gas (Mmcf)
Fort St. John/Parkland – BC	126	183	12,695
Grand Prairie Area – AB	96	31	2,735
Cabin – Kotcho – Junior – BC	-	-	1,605
Other	5	1	54
Total	227	215	17,089

Net of Royalties – Production by Product

2009	Crude Oil ⁽¹⁾ (Mbbls)	NGL (Mmbls)	Natural Gas (Mmcf)
Fort St. John/Parkland – BC	102	147	9,641
Grand Prairie Area – AB	79	21	1,909
Cabin – Kotcho – Junior – BC	-	-	1,270
Other	4	1	43
Total	185	169	12,863

(1) Include condensate production volumes

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2008, the Corporation's share of average daily production volume, prior to royalties, and the prices received, royalties paid, production costs incurred and netbacks on a per unit of volume basis for each product type.

Average Daily Production Volume

Quarter Ended	March 31 2008	June 30 2008	September 30 2008	December 31 2008	Total 2008
Light and Medium Crude Oil (Bbl/d) ⁽¹⁾	579	519	535	686	580
Natural Gas (Mcf/d)	33,525	31,786	37,050	41,919	36,089
NGL (Bbl/d)	333	313	397	489	383
Total BOE/D	6,500	6,130	7,107	8,161	6,978

(1) Includes condensate production volumes

Prices, Royalties Paid, Production Costs and Netback – Light and Medium Crude Oil

\$/Bbl					
Quarter Ended	March 31 2008	June 30 2008	September 30 2008	December 31 2008	Total 2008
Revenue including royalty income	99.30	125.76	119.03	63.63	98.86
Royalties paid	(14.82)	(21.71)	(19.48)	(10.21)	(16.07)
Production costs	(8.44)	(8.42)	(8.63)	(6.95)	(8.04)
Transportation	(5.28)	(5.87)	(4.56)	(4.57)	(5.03)
Netback per barrel	70.76	89.76	86.36	40.90	69.72

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

(\$/Mcf)					
Quarter Ended	March 31 2008	June 30 2008	September 30 2008	December 31 2008	Total 2008
Revenue including royalty income	8.63	10.26	9.01	7.51	8.75
Royalties paid	(1.83)	(2.33)	(2.02)	(1.50)	(1.89)
Production costs	(1.31)	(1.24)	(1.12)	(1.02)	(1.16)
Transportation	(0.34)	(0.32)	(0.28)	(0.27)	(0.30)
Netback per Mcf	5.15	6.37	5.59	4.72	5.40

Prices, Royalties Paid, Production Costs and Netback – NGL

(\$/Bbl)					
Quarter Ended	March 31 2008	June 30 2008	September 30 2008	December 31 2008	Total 2008
Revenue including royalty income	79.29	114.07	99.30	56.68	84.32
Royalties paid	(17.34)	(25.42)	(24.22)	(10.14)	(18.47)
Production costs	-	-	-	-	-
Transportation	(3.45)	(1.83)	(1.33)	(1.16)	(1.84)
Netback per barrel	58.50	86.82	73.75	45.38	64.01

Production Volume by Area

The following table discloses for each major area, and in total, the Corporation's production volumes for the year ended December 31, 2008 for each product type.

Area	Crude Oil ⁽¹⁾ (Bbls/d)	Natural Gas (Mcf/d)	NGLs (Bbls/d)	BOE (Bbls/d)
Fort St. John / Parkland – BC	293	21,942	269	4,219
Cabin/Kotcho/Junior – BC	-	5,303	-	884
Grand Prairie Area – AB	268	8,645	108	1,817
Other	19	199	6	58
Total Production per Day	580	36,089	384	6,978

(1) Include condensate production volumes

SELECTED FINANCIAL INFORMATION

Summary of Operating Results

The following table sets forth selected financial information of the Corporation for the year ended December 31, 2008.

	Year ended December 31, 2008
(M\$, except per share amounts)	
Revenue before royalties	148,524
Funds from operations	87,490
Per share - basic	\$1.96
- diluted	\$1.91
Net income	34,686
Per share - basic	\$0.78
- diluted	\$0.76
Total assets – December 31, 2008	328,376
Bank indebtedness – December 31, 2008	81,904

Note:

(1) Funds from operations and funds from operations per share are non-GAAP measurements that represent cash generated from operating activities before net changes in non-cash working capital items. Funds per share is 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 from operations are not intended to represent or be equivalent to cash flow to operating activities calculated in accordance with Canadian GAAP.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of Storm consists of an unlimited number Common Voting Shares, an unlimited number of Common Non-Voting Shares, an unlimited number of Class "A" Common Voting Shares, an unlimited number of Class "B" Common Non-Voting Shares, an unlimited number of Class I Preferred Shares, issuable in series, an unlimited number of Class II Preferred Shares, issuable in series, and an unlimited number of Class III Preferred Shares, issuable in series. As at December 31, 2008, an aggregate of 43,427,526 Common Voting Shares were issued and outstanding; an aggregate of 1,275,000 Common Non-Voting Shares of the Corporation were issued and outstanding; and no Class "A" common voting shares,

Class “B” common voting shares, Class I preferred shares, Class II preferred shares or Class III preferred shares were issued or outstanding. As at March 31, 2009, an aggregate of 45,277,526 Common Voting Shares were issued and outstanding; an aggregate of 1,275,000 Common Non-Voting Shares of the Corporation were issued and outstanding; and no Class “A” common voting shares, Class “B” common voting shares, Class I preferred shares, Class II preferred shares or Class III preferred shares were issued or outstanding.

The following is a summary of the rights, privileges, restrictions and conditions that will attach to the Common Shares and the Common Non-Voting Shares.

Common Voting Shares

Storm is authorized to issue an unlimited number of Common Voting Shares. Holders of Common Voting Shares (a) are entitled to receive dividends as and when declared by the board of directors of Storm, subject to the rights of holders of shares of any class having priority over the Common Shares, provided that no dividends may be declared in respect of or any benefit conferred upon the holders of the Common Non-Voting Shares unless the same dividend or benefit is conferred upon the holders of the Common Shares, (b) are entitled to share rateably, together with the holders of the Common Non-Voting Shares, in the assets of Storm as are available for distribution in event of any liquidation, dissolution or winding up of Storm or other distribution of the assets of Storm among its shareholders for the purpose of winding up its affairs, subject to the rights of the holders of shares of any class having priority over the Common Voting Shares, and (c) are entitled to receive notice of and to attend any meeting of the shareholders of Storm and to vote at any meeting of shareholders of Storm.

Common Non-Voting

Storm is authorized to issue an unlimited number of Common Non-Voting Shares. Holders of Common Non-Voting Shares (a) are entitled to receive dividends as and when declared by the board of directors of Storm, subject to the rights of holders of shares of any class having priority over the Common Non-Voting Shares, provided that no dividends may be declared in respect of or any benefit conferred upon the holders of the Common Shares unless the same dividend or benefit is conferred upon the holders of the Common Non-Voting Shares, (b) are entitled to share rateably, together with the holders of the Common Shares, in the assets of Storm as are available for distribution in the event of any liquidation, dissolution or winding up of Storm or other distribution of the assets of Storm among its shareholders for the purpose of winding up its affairs, subject to the rights of holders of shares of any class having priority over the Common Non-Voting Shares, and (c) are entitled to receive notice of and to attend any meeting of the shareholders of Storm provided that, except as required by law, holders of Common Non-Voting Shares will not be entitled to vote at any meeting of the shareholders of Storm.

In addition, the terms of the Common Non-Voting Shares provide that such shares will be redeemable at the option of the holder thereof in the event of a bona fide offer (an “Offer”) to acquire all of the issued and outstanding Common Shares, which Offer has not been rejected by holders of the Common Shares holding not less than 50% of the outstanding Common Shares. The redemption price payable in respect of each Common Non-Voting Share redeemed will be the value of the consideration offered under an Offer.

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 of the Corporation on the basis of the Corporation’s earnings, financial requirements and other conditions existing at such future time.

MARKET FOR SECURITIES

On July 2, 2004, the Common Shares were listed and posted for trading on the TSX under the symbol “SEO”. The following table sets forth the price range and trading volume of these securities as reported by the TSX for the period January 1, 2008 to December 31, 2008.

<u>Month</u>	<u>High (\$)</u>	<u>Low (\$)</u>	<u>Volume</u>
January, 2008	10.15	8.52	2,601,894
February, 2008	12.01	10.00	2,708,537
March, 2008	12.20	11.04	1,908,395
April, 2008	14.25	11.74	3,090,162
May, 2008	16.20	13.50	3,275,504
June, 2008	19.41	15.12	5,149,361
July, 2008	19.75	15.51	5,334,391
August, 2008	17.10	14.23	2,154,754
September, 2008	16.18	11.53	4,449,673
October, 2008	13.85	6.92	4,605,238
November, 2008	14.25	10.93	2,753,701
December, 2008	14.15	11.10	4,719,413

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, Saskatchewan and British Columbia, all of which should be carefully considered by investors in the oil and gas industry. 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 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 National Energy Board of Canada (the “NEB”). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

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, Alberta and Saskatchewan 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.

The North American Free Trade Agreement

The North American Free Trade Agreement (“NAFTA”) among the governments of Canada, United States of America 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. Prior to 2007, in the Province of Alberta, a producer of oil or natural gas was entitled to a credit against the royalties payable to the Crown by virtue of the ARTC program. The ARTC provided a rebate on Alberta Crown royalties paid, however this program was phased out on December 31, 2006.

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 new royalty regime effective January 1, 2009 applicable to new and existing conventional oil and natural gas wells in Alberta. 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 will be 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 will be 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 will apply 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 barrels or 500 MMcf of natural gas.

The three-point incentive program also includes an investment of \$30 million by the Government of Alberta in an abandonment and reclamation project for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and gas wells and to stimulate new activity within the services sector.

Subsequent to these changes to the royalty structure, the Alberta provincial government announced that it would launch a study of the competitiveness of Alberta's conventional oil and gas business. Terms of reference for this study have not been made public, however, it is possible that the royalty regime may be subject to further review.

In 2008, approximately 74% of the Corporation's production came from British Columbia and, in 2009, further drilling success in British Columbia where Storm's capital programs are focused will further decrease the proportion of production from Alberta. As a result, the changes to Alberta's royalty regime have limited impact on Storm. Nevertheless, although the majority of Storm's current production and reserves are not affected by Alberta's royalty regime, the Corporation continues to be somewhat active in the Province of Alberta and has a considerable investment in undeveloped land in Alberta. Accordingly, future operations of the Corporation may be more influenced by the changed royalty structure.

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 11,450m³ 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 have been flared, natural gas produced in association with oil has a lower royalty than the royalty payable on non conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the Province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands (“Strategy”). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia’s heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry. This program has evolved over past years as a result of the Province’s stated objective to increase competitiveness, and on March 2, 2009 the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program (“Program”) which allocates \$120 million in royalty credits for oil and gas companies. The Program provides access to royalty credits to oil and gas companies with respect to certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. Companies must apply to the Ministry of Energy and Mines for British Columbia prior to 2:00 p.m. on April 30, 2009 to be considered for approval under the program.
- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

The British Columbia Energy Plan announced on February 27, 2007 outlines the requirements for the development of goals for conservation, energy efficiency and clean energy. In addition, its stated goal is to promote competitiveness through the implementation of a Net Profit Royalty Program (“NPRP”) among others, and facilitate the development of the oil and gas industry. The NPRP’s objective is to share the capital risk of successful developments. Pursuant to the Net Profit Royalty Regulation, the holder of a lease can apply to pay monthly net profit royalties on production of oil and for natural gas wells within a proposed project. The amount paid is calculated on the producers interest in the project, and it ranges from 2% to 5% of the gross revenue and 15% to 35% of the net revenues received. In addition, it depends at which stage the well is, which may be either pre-payout, after-payout or already producing marketable gas.

The British Columbia Government has introduced other royalty programs, in addition to the ones previously mentioned, including a royalty program for deep discovery wells, royalty programs with a stated goal of attracting investment to less productive shallow gas wells (Ultra-Marginal Royalty Program), and the implementation of royalty credits to assist the development of the coalbed gas reserves found in the Province.

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.

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 and penalties, 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.

Environmental legislation is evolving in a manner 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. 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* (the "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 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, 2008, the Corporation owned approximately 248 gross and 153.2 net wells for which abandonment and reclamation costs are expected to be incurred. As disclosed in the Corporation's

consolidated financial statements for the year ended December 31, 2008, the total amount required to settle the Corporation's future asset retirement obligations, including environmental remediation, is estimated to be \$13.0 million, a decrease of \$0.1 million from the year prior. 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.

Kyoto Protocol and Domestic GHG Regulations

In common with all producers, the Corporation's exploration activities and production facilities emit greenhouse gases ("GHG") which directly subjects the Corporation to proposed legislation regulating emissions of GHGs in British Columbia.

Canada is a signatory to the United Nations Framework Convention on Climate Change and in 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. Practically speaking, increases in national emissions and policy announcements of the Government of Canada have brought into question domestic compliance with and enforcement of the Kyoto Protocol requirements. The *Kyoto Implementation Act* was enacted by the government of Canada in 2007, requiring that Canada meet its Kyoto Protocol requirements, however a recent judicial decision has brought into question its enforceability.

In April of 2007 the Government of Canada released a national GHG (and other air emissions) reduction plan titled *Turning the Corner* accompanied by a proposed regulatory framework (the "Regulatory Framework") containing, among other things, near-term intensity based targets and long-term absolute targets for industrial GHG emissions reductions across Canada. In 2008 the targets in the Regulatory Framework were confirmed and additional details of planned federal GHG regulations were announced. The Regulatory Framework indicated that a federal GHG regime would apply to upstream and oil and gas emitting facilities, and would require an 18% intensity based reduction (from 2006 levels) by the end of 2010 for existing facilities, and annual 2% intensity based reductions thereafter. Newer facilities built between 2004 and 2011 would be subject to clean fuel requirements and annual 2% reduction requirements (starting in the fourth year of operations). Facilities commencing operations in 2012 or later will be subject to unique standards by 2018, based in part on the integration of new technology. Proposed compliance mechanisms included: early offset credits; credits for Technology Fund contributions; credits obtained from other regulated entities which improved beyond requirements; offset credits obtained from non-regulated entities which reduced or removed GHGs; or international Clean Development Mechanism (CDM) credits.

For a number of Canadian and North American political and economic reasons, it is now uncertain whether the proposed Regulatory Framework, or a variation thereof, will result in federal GHG regulations reflecting this approach. The Government of Canada is now evaluating both domestic and North American options for a cap and trade regulatory regime, and industrial facility owners across Canada await further information regarding Canada's approach to regulating GHG emissions. In addition to the intensity based reduction targets, the Regulatory Framework proposed a national long-term objective of absolute GHG reductions (from 2006 levels) of 20% by 2020, and of 60-70% by 2050, but did not contain details on how the absolute reductions will be achieved. 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.

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 Government of British Columbia released an Energy Plan in February of 2007 outlining a provincial environmental strategy with a goal of zero net GHG emissions, which promotes investment in research and innovation, and world leadership in sustainable environmental management. A Innovative Clean Energy Fund has been designed to attract new technologies to British Columbia, and its objective with respect to the oil and gas industry is to assist in promoting clean energy, energy efficiency, and conservation practices while remaining competitive to attract oil and gas exploration and development. The Energy Plan also calls for: a new Net Profit Royalty Program; the creation of a Petroleum Registry and infrastructure royalty program (roads, pipelines, etc.); the elimination of flaring at producing wells; emissions reduction policies; tight gas, coalbed gas, and other unconventional development; incentives for increased recoveries from existing reserves; and an Oil and Gas Technology Transfer Incentive Program. In further support of the Energy Plan, in February of 2008 the Government of British Columbia announced intentions to legislate a revenue-neutral carbon tax on all fossil fuels consumed in the province, effective July 1, 2008 and subject to implementation phases beginning at \$10/tonne of CO₂ equivalent in 2009 and increasing to \$30/tonne in 2012. The tax revenue increases are to be offset by tax credits and reductions to be made available by the Government of British Columbia. Storm's 8-13 and 3-9 processing facilities at Parkland are subject to this new carbon tax. The fuel gas being used to run Storm's compressors at both facilities are subject to a tax which increases by \$0.25 per GJ on July 1st of each year from a current level of \$0.4966 per GJ to \$1.4998 per GJ on July 1, 2012. Storm expects payments of this carbon tax to amount to approximately \$350,000 in 2009. Storm plans to minimize the impact of this carbon tax by electrifying both facilities at Parkland over the next two to three years. Electrification of the recently constructed 3-9 facility is planned for the fall of 2009.

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, although 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.

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 evaluation 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.

Capital Markets

As a result of the weakened global economic situation, the Corporation, along with all other oil and gas entities, may have reduced access to bank debt and to equity (the Corporation's primary sources of capital) and is likely to face increased borrowing costs. Although the Corporation's business and asset base have not changed adversely, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of capital markets and investor 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 current expected funds generated from operations along with expected bank availments, the Corporation believes it has sufficient funds available to fund 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.

Royalties

The changes to the Alberta royalty regime described on pages 31 and 32 hereof, as well as the potential for changes in the royalty regimes applicable in other provinces, particularly British Columbia where most of Storm's assets are situated, have created uncertainty surrounding the ability to accurately estimate future royalties, resulting in additional volatility and uncertainty for producers.

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 are 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 equipment 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. See “Industry Conditions”. 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 Regulation”.

Volatility of Oil and Gas Prices

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation’s 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 of the Corporation’s reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation’s production revenue, and, correspondingly, internally generated cash flow, causing a reduction in its oil and gas exploration and development activities. In addition, bank borrowings available to the Corporation are in part determined by the borrowing base of the Corporation. A sustained material decline in prices from historical average prices could further reduce the Corporation’s borrowing base, therefore reducing the bank credit available to the Corporation which may possibly require that a portion of the Corporation’s bank debt be repaid. In addition, banks including Storm’s bankers, have recently sustained considerable losses as a result of exposure to non-performing debt instruments. It is possible that this circumstance may result in a reduction in the amount of credit available to the Corporation or available only on onerous terms.

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 and oil spills, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury 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, pipeline damage and a range of other risks, some of which may not be foreseeable. In addition, economic conditions may affect the solvency of the Corporation’s insurers, for example, if faced with high and simultaneous claim levels.

Availability of Equipment

Oil and natural gas exploration and development activities are dependent on the availability of drilling 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 all 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 produce sour gas, which necessitates the use of equipment built to sour gas specifications. 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 will maintain 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.

Although GHG emissions laws are expected to be implemented in Canada in the next few years, there is currently uncertainty among industry as to the potential application and extent of reduction requirements, and potential compliance options. As a result, it is not possible to predict the operational and financial impacts of future GHG emissions laws, if any, applicable to the Corporation.

Accounting for Oil and Gas Properties

The Corporation uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed at least annually for impairment to ensure that the carrying amount of these costs is recoverable based on forecast future cash flows plus the cost of undeveloped properties. To the extent that such capitalized costs (net of accumulated depreciation and depletion) less future taxes exceed the present value of estimated future net cash flows from the Corporation's proved oil and natural gas reserves, those excess costs would be required to be charged to operations. Further detail is provided in the Corporation's consolidated financial statements for the year ended December 31, 2008.

Adoption of IFRS

The adoption by the Canadian Institute of Chartered Accountants of International Financial Reporting Standards, effective January 1, 2011, is likely to result in fundamental changes to accounting for oil and gas activities.

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.

Interest Rates

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt with a corresponding reduction in Storm's cash flow and its investment capacity.

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, 2008 by Paddock. 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 increase the Corporation's debt levels above acceptable levels. Depending on future exploration and development plans, the Corporation may require additional financing 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 CBCA.

Dependence on Key Personnel

Storm's success depends in large measure on certain key personnel including Brian Lavergne, Donald G. McLean, Harry Ediger, Eric Blakely, Robert S. Tiberio 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.

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, or before the most recently completed financial year, but still in effect, can reasonably be regarded as presently material to Storm.

INTERESTS OF EXPERTS

As of the date hereof, the partners and associates of PricewaterhouseCoopers LLP, the auditors of Storm, as a group, held no Common Shares directly and indirectly in the Corporation.

As of the date hereof, principals of Paddock, as a group, held no Common Shares directly and indirectly in the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares of Storm is Valiant 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 financial information is provided in the Corporation's audited consolidated financial statements, and Management's Discussion and Analysis for the year ended December 31, 2008. Management and auditors' reports on the financial statements are dated February 23, 2009 and Management's Discussion and Analysis is dated February 23, 2009.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions is contained in the Corporation's Information Circular dated March 31, 2009. A copy of the Information Circular may be obtained from the SEDAR website at www.sedar.com.

APPENDIX A

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

This is the form referred to in item 2 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

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

To the board of directors of Storm Exploration Inc. (the "Corporation"):

1. We have evaluated the Corporation's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Corporation'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 Corporation evaluated by us for the year ended December 31, 2008.

¹ For the convenience of readers, CSA Staff Notice 51-324 Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities 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
Paddock Lindstrom & Associates Ltd.		Canada	-	\$755,472,000	-	\$755,472,000
Totals			-	\$755,472,000	-	\$755,472,000

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Paddock Lindstrom & Associates Ltd, Calgary, Alberta, Canada,

“D.L. Paddock, P.Eng.”

 D.L. Paddock, P. Eng.
 Vice President

March 31, 2009

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

Management of Storm Exploration Inc. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31,2008 estimated using forecast prices and costs.

Paddock Lindstrom & Associates Ltd., independent qualified reserves evaluators, has evaluated the Corporation'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 Corporation has

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

- (d) the content and filing with securities regulatory authorities of Form 51-101 F1 containing reserves data and other oil and gas information;
- (e) the filing of Form 51-101 F2 which is the report of the independent qualified reserves evaluators on the reserves data; and
- (f) 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

“Brian Lavergne”

Brian Lavergne
President and Chief Executive Officer

“Donald G. McLean”

Donald G. McLean
Vice President, Finance and Chief Financial Officer

“Matthew J. Brister”

Matthew J. Brister
Director

“Henry Lawrie”

Henry Lawrie
Director

“Grant Weirzba”

Grant Weirzba
Director and Chairman of the Reserves Committee

March 31, 2009

APPENDIX C

STORM EXPLORATION INC. AUDIT COMMITTEE TERMS OF REFERENCE

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

I. The Board of Directors

The Board of Directors ("Board") has responsibility for the stewardship of Storm Exploration Inc. (the "Company"). To discharge that responsibility, the Board is obligated by the Canada Business Corporations Act) 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 consider whether, in all material respects:

- (a) 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) the accounting principles, significant judgements and disclosures which underlie or are incorporated in the Company's financial statements are appropriate in the prevailing circumstances;
- (c) 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 results in accordance with generally accepted accounting principles ("GAAP"); and
- (d) 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 by management:

- (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 and are as required by securities law, properly certified;
- (ii) the internal financial controls are regularly assessed for effectiveness and efficiency as part of reviews of interim and annual financial statements and management's discussion and analysis ("**MD&A**")
- (iii) the Company's quarterly and annual financial statements, and MD&A thereof are properly prepared by management to comply with GAAP and securities law requirements; 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.

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

III. 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 GAAP; 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.

IV. Limitations on Committee's Duties

In contributing to the Committee's discharging of its duties under these Terms of Reference, each member of the Committee 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 but limited 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.

B. Audit Committee Terms of Reference

These Terms of Reference outline 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;

- Specific Responsibilities and Duties.

I. *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 Company and Committee advisors or Company staff members as applicable. In particular, management will ensure that any complaints regarding accounting, financial control or audit matters, are directed immediately to the chair of the Audit Committee.

3. *Financial Literacy*

All Audit 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 Audit 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 affect the Company's financial disclosure.

The work plan will be focused primarily on the annual and interim financial statements and MD&A 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 or other statutory requirements.

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.

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 and discuss its own performance. In addition, the Committee shall at least once a year 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 Audit 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.

II. Operating Procedures

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

III. Specific Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall:

Financial Reporting

6. 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 but limited assurance (but not to ensure) that the statements (i) are accurate within reasonable levels of materiality, (ii) complete, and (iii) represent fairly the Company's financial position and results in accordance

with GAAP. The Committee shall report thereon to the Board before such financial statements are approved by the Board.

7. Receive from the external auditors reports on their review of the annual and quarterly financial statements.
8. 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.
9. 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.
10. 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.
11. Review 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 shall not include complaints about minor issues. (Examples of minor issues include late payment of invoices, disputes over immaterial accounts owing or receivable or payable, revenue and expense allocations and other similar items characteristic of the normal daily operations of the accounting department of an oil and gas company.)
12. Review and insure the public disclosure of the Company's procedure for receiving and dealing with complaints is clearly articulated.

Accounting Policies

13. 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.
14. Obtain reasonable assurance that they are in compliance with GAAP from management and external auditors and report thereon to the Board.
15. 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 the quality of financial reporting.
16. Participate, as applicable, in the resolution of disagreements, between management and the external auditors.

Risk and Uncertainty

17. Acknowledging that it is the responsibility of management and of interest to the Board, 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 reviewing with management:
 - (a) the Company's tolerance for financial risks;

- (b) its assessment of the significant financial risks facing the Company;
 - (c) the Company's policies and any proposed changes thereto for managing those significant financial risks; and
 - (d) its plans, processes and programs to manage and control such risks.
18. Review actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion.
 19. Review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments.
 20. Review the adequacy of insurance coverages maintained by the Company.
 21. 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

22. When required, 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.
23. Receive regular reports from management and the external auditors on all significant deviations from GAAP or the Company's internal control processes or indications which may suggest fraud and the corrective activity undertaken in respect thereto.
24. Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Committee, 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 judgement, through existing reporting structures in the Company.
25. Review, and periodically consider 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

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

Relationship with External Auditors

28. Recommend to the Board the nomination of the external auditors.
29. Approve the remuneration and the terms of engagement of the external auditors as set forth in the Engagement Letter for (i) the annual audit, (ii) the quarterly reviews and (iii) other services.
30. Review the performance of the external auditors annually or more frequently as required.
31. 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.
32. 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 provided to the Company.
33. 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.
34. Meet with the external auditors in the absence of management to consider, *inter alia*, whether 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.
35. 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.
36. 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 judgement of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee of any disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved.

Other Responsibilities

37. Consider annually the reasonableness of the expenses of the Chairman of the Board and the Chief Executive Officer.
38. After consultation with the Chief Financial Officer and the external auditors, consider at least annually the quality and sufficiency of the Company's accounting and financial personnel and other resources.
39. Approve in advance non-audit services, including tax advisory and tax compliance services, provided by the external auditors. However, the Committee may establish the nature and 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 is to be provided to the Committee at the next following meeting.
40. Investigate any matters that, in the Committee's discretion, fall within the Committee's duties.
41. Perform such other functions as may from time to time be assigned to the Committee by the Board.

42. Review and update the Terms of Reference on a regular basis for approval by the Board.
43. The Committee is to 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, MD&A, information circulars and annual information forms.
44. Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Company.
45. Cooperate and discuss matters of common interest between financial audit and reserves evaluation or audit committees.

The audit committee must approve the hiring or engagement of any partner or employee of the present or former external auditor of the Company.