

STORM EXPLORATION INC.

RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2007

MARCH 28, 2008

TABLE OF CONTENTS

NOTE REGARDING FORWARD-LOOKING STATEMENTS	i
SELECTED ABBREVIATIONS	1
CONVERSION	1
CURRENCY OF INFORMATION	2
THE CORPORATION	2
GENERAL DEVELOPMENT OF THE BUSINESS	3
2007 Developments	3
2006 Developments	3
2005 Developments	4
Significant Acquisitions	4
NARRATIVE DESCRIPTION OF BUSINESS	4
MANAGEMENT OF THE CORPORATION	6
AUDIT COMMITTEE	11
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	12
SELECTED FINANCIAL INFORMATION	26
DESCRIPTION OF SHARE CAPITAL	26
DIVIDENDS	27
MARKET FOR SECURITIES	28
INDUSTRY CONDITIONS	28
RISK FACTORS	33
MATERIAL CONTRACTS	36
INTERESTS OF EXPERTS	36
TRANSFER AGENT AND REGISTRAR	37
ADDITIONAL INFORMATION	37
APPENDIX A - FORM 51-101F2	A-1
APPENDIX B - FORM 51-101F3	B-1
APPENDIX C - AUDIT COMMITTEE TERMS OF REFERENCE	C-1

NOTE REGARDING FORWARD-LOOKING STATEMENTS

All forward-looking statements in this Annual Information Form (“AIF”), and in certain documents incorporated by reference herein, 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:

- volatility in market prices for oil and natural gas;
- 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;
- the other factors discussed under “Risk Factors” herein;
- those material risks discussed in Storm’s Management’s Discussion & Analysis under Risk Assessment.

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 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 annual information form, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbl	thousand barrels
Mmbbl	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
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 annual information form is stated as at December 31, 2007 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 Peace River Arch area of Alberta and British Columbia, Kotcho/Cabin/Junior in north eastern British Columbia and Red Earth in north central 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.

Under the Plan of Arrangement the Corporation also received a 26% (now 13%) 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 and holds a significant interest in a 1.2 million acre exploratory permit at Remada Sud in the Ghadames basin in south east Tunisia and has a 100% interest in the Hammamet Offshore Exploration Block comprising approximately 1.1 million acres in the Pelagian Basin offshore Tunisia. In 2005, SVI completed a 225 kilometre seismic program in the Remada Sud area and completed the drilling and evaluation of its first exploratory test. The well was suspended after non-commercial quantities of oil were recovered from the Silurian Acacus formation. In 2008, SVI plans to drill a second onshore well that will test one of two large structures in the Remada Sud area. Each has potential gas in place of 200 Bcf. Offshore Tunisia, nine prospects have been identified through a review of available 2-D seismic data over the Gulf of Hammamet block. A 400 to 500 square kilometre marine 3-D seismic program was completed in the summer of 2007 to better define these prospects. One well is planned for late 2009 or 2010. Also, in 2007, SVI has agreed to acquire interests in two additional offshore concessions which were not part of the original offshore Gulf of Hammamet block. In late 2005 SVI, through a 37% owned UK registered affiliate, Silverstone Energy Limited, (“Silverstone”), entered into a farm-in the prolific V-fields area of the United Kingdom sector of the North Sea. In 2006, three wells were successfully drilled in the Viking Field area of the southern North Sea, with the three discoveries having estimated gas in place approximating 320 Bcf. One of these discoveries is expected to be developed in late 2008. During 2008, an additional three wells are planned in the North Sea, with one well targeting a 40 to 100 Mmbbl medium gravity oil prospect in the central North Sea Mariner-Gryphon area and two other wells targeting 75 Bcf gas prospects in the Viking Field.

On March 18, 2008 Silverstone bid to acquire 100% of the outstanding shares of AIM listed Granby Oil and Gas Plc. for £23.1 million and the assumption of approximately £31 million of project based debt. Granby’s assets are concentrated in the company’s core areas in the Southern Gas Basin and the heavy oil fairway in

Quad 9 of the central North Sea. The major asset is a 54% operated interest in the Tristan NW Field which is due to commence production by mid April and will represent Silverstone's first production. The transaction will be financed in part by a 5 million share rights offering that will be completed in April. Silverstone has irrevocable commitments from 42% of Granby's shareholders prior to the offer and purchased shares in the market to hold in excess of 50% of the shares shortly after the transaction was announced. If successful, the offer will close after April 8, 2008.

Storm is a reporting issuer (or the equivalent) in the provinces of British Columbia, Alberta, Ontario and Québec. 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

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. 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 and a continuing high level of investment in this area is expected in 2008.

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. 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.

2005 Developments

In 2005, the Corporation participated in no major acquisition or disposition transaction. Minor acquisitions totalled \$4.4 million and minor dispositions totalled \$3.3 million, including an asset sale and farmout agreement with a private industry partner, the terms of which included the investment by Storm of \$100,000 in common shares of the private entity. Subsequently, the investee company completed an initial public offering and Storm sold its investment for proceeds, after transaction costs, of \$1,784,000.

Net capital expenditures totalled \$42.6 million in 2005 and were funded by operating cash flow and increased debt. No shares were issued during the year, except upon exercise of stock options, performance warrants and share purchase warrants. Operational growth was supported by an expansion of the Company's bank line of credit.

The Corporation began 2005 with a 26% ownership position in SVI. During 2005, SVI completed a private placement offering of common shares, with the Corporation participating in a rights offering component of the private placement. Nevertheless, as a result of the private placement, Storm's equity interest in SVI was reduced from 26% to 16%. Storm's participation in the private placement by SVI amounted to \$2,000,000, largely funded by proceeds from the sale of the above common share investment. Storm's participation in the rights offering was, and remains, consistent with the Corporation's policy of ensuring that its investment in SVI does not conflict with its domestic investment programs.

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 will 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 balances its aggressive operating philosophy with a conservative financial strategy, based on funding the Corporation's capital expenditure program out of cash flow, available debt (within a defined 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; 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 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 oil and gas industry is highly competitive. The Corporation's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities, include companies that have greater financial and personnel resources available to them than the Corporation.

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 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 efficient transactions in a highly competitive environment.

Cyclical Nature of Business

The oil and natural gas business in western Canada is generally cyclical. However, Storm's properties generally, with the exception of Kotcho/Cabin/Junior in north eastern British Columbia, provide year round access, enabling drilling and workover activities to continue throughout the year. Storm's revenue from the sale of natural gas (approximately 87% of total revenue) can, however, be seasonal, with demand, and hence pricing, for natural gas rising during cold winter months and hot summer months.

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 rapidly 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 and 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.

Employees

As of December 31, 2007, the Corporation had 26 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>
Matthew J. Brister ^{(1) (3)} London, U.K.	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	
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
John A. Brussa ⁽²⁾ Calgary, Alberta	Director	June 29, 2004

<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	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 Weirzba ⁽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 11,901,822 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.

Matthew J. Brister, Chairman and 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 has been the Chairman of the Corporation since completion of the Plan of Arrangement. 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 Storm Energy Inc. ("SEI"). From May, 1987 to July, 1998, Mr. Brister was employed by Pinnacle Resources Ltd. ("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.

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 its Chief Operating Officer. From December, 1998 until August 2003, 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 is a 1983 graduate of the University of Calgary, 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 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, Corporate Secretary

Mr Turnbull is the Regional Managing Partner of the Calgary office of McCarthy Tétrault 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 is currently a director of Storm Exploration Inc., Heritage Oil Corporation, Seaview Energy Inc., Sunshine Oilsands Ltd., BNP Resources Inc., Action Energy Inc., Flagship Energy Inc. and Mohave Exploration & Production Inc., all publicly traded entities listed on the TSX or TSX Venture Exchange.

Throughout his career, he has served as an officer or director of Baytex Energy Ltd., Barrington Petroleum Ltd., Castle Rock Petroleum., 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.

John A. Brussa, Director

Mr. Brussa is a partner in the Calgary-based energy 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 reporting issuers: 1322256 Alberta Ltd. (formerly Inex Pharmaceuticals Corporation), 6550568 Canada Inc., Baytex Energy Ltd. (Baytex Energy Trust), BlackWatch Energy Services Operating Corp. (BlackWatch Energy Services Trust), Cirrus Energy Corporation, Crew Energy Inc., Divestco Inc., Endev Energy Inc., Enseco Energy Services Corp., Flagship Energy Inc., Galleon Energy Inc., Harvest Operations Corp. (Harvest Energy Trust), Highpine Oil & Gas Limited, 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 Ltd. (Progress Energy Trust), Strategic Energy Fund and Trafalgar Energy Ltd.

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.

Stuart G. Clark, Director

Mr. Clark has a Bachelor of Commerce (Honours) from the University of Manitoba. Mr. Clark was the Executive Director of SEM from August, 2002 to May, 2003. Prior to August, 2002 Mr. Clark was Vice President, Finance and Chief Financial Officer of 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 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.

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., Delphi Energy Corp. and Flagship Energy Inc.

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, there has been no director or officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation that is, or within the 10 years before the date of this annual information form has been a director or officer of any other issuer that, while that person was acting in that capacity:

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

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 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 their 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 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 their ability to act with a view to the best interests of Storm.

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 under section 1.5 of Multilateral

Instrument 52-110 (“MI 52-110”). All members of the Audit Committee are independent as such term is described under section 1.4 of MI 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, 2007 were \$70,000.

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, 2007 were \$24,000.

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, 2007 were \$8,700.

All Other Fees

Fees for additional advice were \$4,000.

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 17, 2008. The Paddock Report evaluated, as at December 31, 2007, Storm’s crude oil, NGL and natural gas reserves. The Paddock December 31, 2007 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 such Reports 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	551	46,899	773	9,141	495	37,790	600	7,393
Developed Non-Producing	0	2,601	31	465	0	2,130	24	379
Undeveloped	355	13,605	368	2,990	306	11,149	308	2,472
Total Proved	906	63,105	1,172	12,596	801	51,069	932	10,244
Probable	427	39,519	867	7,880	370	32,074	710	6,426
Total Proved plus Probable	1,333	102,624	2,039	20,476	1,171	83,143	1,642	16,670

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	289,534	225,821	189,780	165,984	148,793
Developed Non-Producing	12,335	10,113	8,616	7,534	6,709
Undeveloped	102,172	67,395	50,206	39,691	32,462
Total Proved	404,041	303,329	248,602	213,209	187,964
Probable	294,402	169,923	120,401	93,436	76,022
Total Proved plus Probable	698,443	473,252	369,003	306,645	263,986

After Future Income Tax and Discounted at					
	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Proved					
Developed Producing	265,169	206,750	173,525	151,563	135,704
Developed Non-Producing	8,800	7,176	6,084	5,298	4,702
Undeveloped	73,804	47,727	34,750	26,785	21,305
Total Proved	347,773	261,653	214,359	183,646	161,711
Probable	214,028	122,029	85,321	65,306	52,381
Total Proved plus Probable	561,801	383,682	299,680	248,952	214,092

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	Future	Future Net
						Revenue Before Income Tax (M\$)	Income Tax (M\$)	Revenue After Income Tax (M\$)
Total Proved	706,997	128,441	147,298	23,073	4,144	404,041	56,268	347,773
Total Proved plus Probable	1,207,261	215,318	240,759	47,656	5,085	698,443	136,642	561,801

Future Net Revenue by Production Group

		Future Net Revenue	Unit Value
		Before Income Taxes (Discounted at 10%) (M\$)	(\$/Mcf) (\$/Bbl)
Proved	Light and Medium Crude Oil	27,069	\$29.89 Bbl
	Heavy Crude Oil	-	-
	Natural Gas	221,533	\$3.55 Mcf
	Total	248,602	
Proved Plus Probable	Light and Medium Crude Oil	35,786	\$26.84 Bbl
	Heavy Crude Oil	-	-
	Natural Gas	333,217	\$3.28 Mcf
	Total	369,003	

Future net revenues from natural gas exclude solution gas but does 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, 2007 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)		
2008	7.75	6.80	90.00	88.75	71.00	53.25	2	1.000
2009	8.25	7.28	88.00	86.73	69.38	52.04	2	1.000
2010	8.42	7.43	84.00	82.70	66.16	49.62	2	1.000
2011	8.58	7.58	82.00	80.67	64.54	48.40	2	1.000
2012	8.75	7.73	80.00	78.65	62.92	47.19	2	1.000
2013	8.93	7.88	81.60	80.22	64.18	48.13	2	1.000
2014	9.11	8.04	83.23	81.82	65.46	49.09	2	1.000
2015	9.29	8.20	84.90	83.46	66.77	50.08	2	1.000
2016	9.48	8.36	86.59	85.13	68.10	51.08	2	1.000
2017	9.67	8.53	88.33	86.83	69.47	52.10	2	1.000
2018	9.86	8.70	90.09	88.57	70.86	53.14	2	1.000
2019	10.06	8.88	91.89	90.43	72.27	54.20	2	1.000
2020	10.26	9.05	93.73	92.15	73.72	55.29	2	1.000
Thereafter +2% per annum								

The weighted average realized sales prices including hedging for the year ended December 31, 2007 were \$7.08 Mcf for natural gas, \$75.82Bbl for crude oil and \$66.44Bbl 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, 2007 against such reserves as at December 31, 2006 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, 2006	919	515	1,434	515	154	669	48,665	18,998	67,663	9,545	3,835	13,380
Acquisitions	8	2	10	58	15	73	4,582	1,224	5,806	830	221	1,051
Revisions	410	(40)	370	331	362	693	(6,251)	(5,346)	(11,597)	(301)	(569)	(870)
Discoveries	-	-	-	354	340	694	28,245	27,090	55,335	5,062	4,855	9,917
Extensions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(250)	(50)	(300)	(3)	(4)	(7)	(310)	(2,195)	(2,505)	(305)	(420)	(725)
Economic Factors	-	-	-	-	-	-	(762)	(252)	(1,014)	(127)	(42)	(169)
Production	(181)	-	(181)	(83)	-	(83)	(11,064)	-	(11,064)	(2,108)	-	(2,108)
December 31, 2007	906	427	1,333	1,172	867	2,039	63,105	39,519	102,624	12,596	7,880	20,476

Net 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, 2006	808	437	1,245	401	120	521	37,975	14,695	52,670	7,538	3,006	10,544
Acquisitions	7	2	9	46	12	58	3,708	993	4,701	671	180	851
Revisions	367	(26)	341	271	303	574	(4,195)	(3,472)	(7,667)	(62)	(301)	(363)
Discoveries	-	-	-	282	278	560	22,858	21,987	44,845	4,092	3,943	8,035
Extensions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(221)	(43)	(264)	(2)	(3)	(5)	(251)	(1,781)	(2,032)	(265)	(344)	(609)
Economic Factors	-	-	-	-	-	-	(72)	(348)	(420)	(12)	(58)	(70)
Production	(160)	-	(160)	(66)	-	(66)	(8,954)	-	(8,954)	(1,718)	-	(1,718)
December 31, 2007	801	370	1,171	932	710	1,642	51,069	32,074	83,143	10,244	6,426	16,670

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)
2008	23,073	47,483
2009	-	-
2010	-	173
2011	-	-
2012	-	-
2013	-	-
2014	-	-
2015	-	-
2016	-	-
Remaining Years	-	-
Total Undiscounted	23,073	47,656
Total Discounted at 10% per year	21,996	45,403

The Corporation estimates that its internally generated cash flow 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.

The Corporation expects to fund its total 2008 capital program with internally generated cash flow 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:

Peace River Arch, Northwest Alberta and Northeastern British Columbia

The Peace River Arch is Storm's largest operating area with current production approximating 5,700 Boe per day. A total of 19 wells were drilled in this area in 2007, with a 90% success rate, resulting in 14.4 net oil and gas wells. The area is largely year round access and offers multiple play types and multiple horizon opportunities. Products are natural gas and associated liquids and light sweet crude oil providing high netbacks. The Corporation operates most of its production and drilling in this area.

Cabin/Kotcho/Junior, Northeastern British Columbia

This area is largely winter access and drilling targets natural gas in the prolific but higher risk Slave Point formation. Storm has not been active in this area in the winter of 2007 – 2008. Current production approximates 950 Boe per day.

Oil and Gas Wells

The following table summarizes the Corporation's interest as at December 31, 2007 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	36	23	49	21	22	13	42	25
British Columbia	2	1	39	33	1	0.3	25	20
Totals	38	24	88	54	23	13.3	67	45

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, 2007		
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Red Earth, Alberta	78,660	66,000	20,171
Kotcho/Cabin/Junior	56,191	36,000	5,174
Peace River Arch	99,827	79,000	1,121
Other	74,073	45,000	7,289
Total	308,751	226,000	33,755

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, 2007.

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	0	0	0	0	0	0
Natural gas wells	16	14.3	3	2.1	19	16.4
Service wells	-	-	-	-	-	-
Dry holes	3	2	3	2.3	6	4.3
Total	19	16.3	3	4.4	25	20.7

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 148 (98 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 \$1.2 million using a 10% discount rate. Abandonment and reclamation costs for future undeveloped drilling locations are not yet included. Storm owns an interest in 216 wells (136.3 net). Per the reserves report, over the next three years, Storm's net well abandonment cost is expected to total \$242,000. Storm's total undiscounted net cost to abandon and reclaim all wells, facilities and pipelines (net of salvage) is expected to be \$5.1 million.

Tax Horizon

The Corporation has resource pools of approximately \$208 million available for deduction against future taxable income. As at December 31, 2007 the Corporation also has a capital loss in the amount of \$9.7 million, available for application against future capital gains. As a result the Corporation does not expect to pay income tax in 2008. However, measurement of losses and tax pools and their availability, are subject to concurrence or potential audit by Canada Revenue Agency.

Costs Incurred

The following table summarizes the Corporation's property acquisition costs, exploration costs and development costs for the year ended December 31, 2007, net of dispositions of proved properties of \$3.1 million.

Total (M\$)	Property Acquisition Costs (\$000)			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
	24,485	3,860	44,099	21,446

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 2008.

2008	Crude Oil (Mbbls)	NGL (Mmbls)	Natural Gas (Mmcf)
Peace River Arch	110.1	267.9	12,776
Kotcho-Cabin	-	-	1,965
Other	5.1	4.7	72
Total	115.2	272.6	14,813

Net of Royalties – Production by Product

2008	Crude Oil (Mbbls)	NGL (Mmbls)	Natural Gas (Mmcf)
Peace River Arch	91.8	217.1	9,943
Kotcho-Cabin	-	-	1,529
Other	4.0	2.1	61
Total	95.8	219.2	11,533

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2007, 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 2007	June 30 2007	September 30 2007	December 31 2007	Total 2007
Light and Medium Crude Oil (Bbl/d)	553	514	404	514	496
Natural Gas (Mcf/d)	30,048	29,891	30,104	31,133	30,296
NGL (Bbl/d)	216	217	197	289	230
Total BOE/D	5,776	5,713	5,618	5,992	5,775

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

Quarter Ended	March 31 2007	June 30 2007	September 30 2007	December 31 2007	Total 2007
Revenue including royalty income	\$65.37	72.27	81.55	87.88	76.36
Royalties paid	(10.63)	(11.35)	(12.66)	(13.92)	(12.09)
Production costs	(6.88)	(8.46)	(9.44)	(7.99)	(8.10)
Transportation	(1.69)	(2.34)	(3.56)	(4.71)	(3.03)
Netback per barrel	\$46.17	50.12	55.89	61.26	\$53.14

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

Quarter Ended	March 31 2007	June 30 2007	September 30 2007	December 31 2007	Total 2007
Revenue including royalty income	\$8.74	7.54	5.51	6.79	\$7.13
Royalties paid	(1.75)	(1.68)	(1.14)	(1.47)	(1.51)
Production costs	(1.23)	(1.31)	(1.14)	(1.19)	(1.22)
Transportation	(0.36)	(0.38)	(0.39)	(0.34)	(0.37)
Netback per Mcf	\$5.40	4.17	2.84	3.79	\$4.03

Prices, Royalties Paid, Production Costs and Netback – NGL

Quarter Ended	March 31 2007	June 30 2007	September 30 2007	December 31 2007	Total 2007
Revenue including royalty income	\$57.72	63.19	71.94	73.36	\$67.04
Royalties paid	(17.21)	(15.09)	(20.54)	(17.96)	(17.67)
Production costs	-	-	-	-	-
Transportation	(3.26)	(4.82)	(4.29)	(3.63)	(3.97)
Netback per barrel	\$37.25	43.28	47.11	51.77	\$45.40

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, 2007 for each product type.

Area	Crude Oil (Bbl/d)	Natural Gas (Mcf/d)	NGLs (Bbl/d)	BOE (Bbl/d)
Peace River Arch	431	23,951	222	4,644
Cabin/Kotcho/Junior	-	6,061	-	1,010
Red Earth, Alberta	62	-	-	62
Other	3	284	8	59
Estimated Total Production per Day	496	30,296	230	5,775

SELECTED FINANCIAL INFORMATION

Summary of Operating Results

The following table sets forth selected financial information of the Corporation for the year ended December 31, 2007.

	Year ended December 31, 2007
(M\$, except per share amounts)	
Revenue before royalties	98,291
Cash flow from operations	51,943
Per share - basic	1.20
- diluted	1.18
Net income	11,049
Per share - basic	0.25
- diluted	0.25
Total assets – December 31, 2007	260,907
Bank indebtedness – December 31, 2007	74,472

Note:

- (1) Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital items. Cash flow per share is calculated on the same basis as earnings per share.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of Storm consists of an unlimited number Common 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, and 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, 2007, an aggregate of 43,256,965 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 Shares

Storm is authorized to issue an unlimited number of Common Shares. Holders of Common 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 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 Venture Exchange and the TSX for the period January 1, 2007 to December 31, 2007.

<u>Month</u>	<u>High (\$)</u>	<u>Low (\$)</u>	<u>Volume (\$)</u>
January, 2007	\$7.15	\$6.30	779,602
February, 2007	\$7.35	\$6.36	1,002,665
March, 2007	\$7.80	\$6.76	893,746
April, 2007	\$8.95	\$7.41	997,912
May, 2007	\$9.43	\$8.10	760,979
June, 2007	\$9.25	\$8.15	766,044
July, 2007	\$9.04	\$7.48	431,091
August, 2007	\$9.10	\$7.27	725,008
September, 2007	\$8.87	\$7.50	1,274,860
October, 2007	\$9.09	\$7.90	670,761
November, 2007	\$9.10	\$8.15	2,606,370
December, 2007	\$8.90	\$8.11	829,445

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 lands other than Crown lands 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 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.

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. This program was phased out on December 31, 2006.

Crude oil and natural gas royalty holidays for specific wells and royalty reduction reduce the amount of Crown royalties paid by the Corporation to the provincial governments. In general, the ARTC provides a rebate on Alberta Crown royalties paid.

On October 25, 2007 the Provincial Government of Alberta announced changes to the provincial royalty regime to be effective January 1, 2009. Final details relating to the royalty changes are not yet available; however the total amount of royalties to be paid by producers to the Provincial Treasury will increase considerably. High productivity wells will be subject to the highest levels of increase; however, as the new royalty arrangements reflect both well productivity and commodity pricing, royalty levels for lower productivity wells may be reduced. In 2007 approximately 62% of the Corporation's production came from British Columbia; in 2008, successful drilling may result in production from British Columbia increasing to 80%. Nevertheless, although Storm's current operations are to a degree protected from the full affect of the new royalty regime, the Corporation continues to have activity in the Province of Alberta and has a considerable investment in undeveloped land in the province. Accordingly, it is likely that future operations of the Corporation will be affected by the changed royalty structure, possibly materially so.

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. 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. 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 expected to result in stricter standards and enforcement, larger fines and 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. Although the Corporation maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is by no means assured that such insurance will cover all possible events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance invalid. Furthermore, the Corporation expects incremental future costs associated with compliance with 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.

As at December 31, 2007, the Corporation owned approximately 216 gross and 136.3 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, 2007, the total amount required to settle the Corporation's future asset retirement obligations, including environmental remediation, is estimated to be \$13.1 million, an increase of \$1.3 million over the year prior. The Corporation estimates abandonment and reclamation costs by taking consideration the costs associated with decommissioning, abandonment, remediation and reclamation, and also includes the salvage values of any existing equipment which can be reasonably salvaged, all adjusted according to the Corporation's working interest and discounted in accordance with NI 51-101. Such costs and salvage values are individually attributed to assets then aggregated to determine the aggregate liability

The oil and gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for 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.

Environmental legislation in the Province of Alberta has been consolidated into 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 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

The Corporation's exploration and production facilities and other operations and activities will emit a small amount greenhouse gasses ("GHG") which may subject the Corporation to existing and proposed legislation regulating emissions of GHGs. 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 of GHG emissions. This is an absolute GHG emissions reduction target. Although the policy announcements of the Government of Canada have brought into question domestic compliance with and enforcement of the Kyoto Protocol requirements, Bill C-288, the *Kyoto Implementation Act*, was passed by the House of Commons on February 14, 2007 intending that Canada meet its Kyoto Protocol GHG reduction requirements, and remains in force today.

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. On March 10, 2008 the targets in the Regulatory Framework were confirmed and

additional details of pending federal GHG regulations, including the details of the tradable compliance mechanisms and the establishment of a domestic carbon trading market, were announced. The Regulatory Framework indicates that the federal GHG regime will apply to upstream and oil and gas emitters likely including the Corporation. The Regulatory Framework requires an 18% intensity based reduction (from 2006 levels) by the end of 2010 for existing facilities, and annual 2% intensity based reductions thereafter. For newer facilities built between 2004 and 2011, the Regulatory Framework mandates clean fuel adjustments to a newer facility's baseline GHG emissions from which the annual 2% improvements (starting in its fourth year of operations) must be made. Facilities commencing operations in 2012 or later will be subject to unique standards by 2018 based in part on the integration of CCS or other green technology at such new facilities. If a facility is not able to abate GHG emissions sufficiently to meet the reduction target, it may utilize other compliance mechanisms, namely: early offset credits for improvements realized between 1992 and 2006; credits for Technology Fund contributions; credits obtained from other regulated entities which improved beyond requirements; offsets obtained from non-regulated entities which reduced or removed GHGs from business as usual practices; or Clean Development Mechanism (CDM) credits obtained from international markets. While Technology Fund contributions are likely to be the preferred compliance mechanism in the early years, Technology Fund contribution costs increase and contribution limits decline from 70% in 2010 to 0% by 2018 meaning that regulated facilities will be required to abate or participate in the domestic carbon trading market to meet reduction requirements. Technology Fund proceeds will be available for future technology investments, and may also be obtained indirectly for investments made in large-scale and transformative projects. CDM credits (generated via the Kyoto Protocol CDM program) will also be limited in type and in quantity to 10% of a firm's compliance obligation. The offsets system will therefore eventually play a greater role as a compliance option, and is to be established nationally and administered such that proven GHG reductions or removals achieved by non-regulated projects, facilities, or entities may be sold to regulated entities.

In addition to the intensity based reduction targets, the Regulatory Framework also proposes a national long-term objective of absolute GHG reductions (from 2006 levels) of 20% by 2020, and by 60-70% by 2050, but does not contain details on how the absolute reductions will be achieved.

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 obtain compliance mechanisms which deem the facility in compliance, namely: (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 from business as usual; 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 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 or green 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.

The Corporation anticipates that future federal legislation will require the reduction of emissions or emissions intensity with 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. A federal-provincial (Alberta) CCS Task Force released a report in January of 2008 recommending, among other things, that: (i) CCS receive annual federal budget funds in the immediate term; (ii) CCS incentives and/or requirements be incorporated into GHG regulations; and (iii) domestic research be targeted to CCS technology developments.

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.

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 a material 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 net 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 net production revenue 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.

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, 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, 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 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 impact on the Corporation's ability to finance future investment.

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 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. However 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.

Title Reviews

Although title reviews will be completed according to industry standards prior to the purchase of most oil and natural gas producing 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.

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, 2007 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 a material 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 co-transfer agents and registrars for the Common Shares of Storm are Valiant Trust Company at its office in Calgary, Alberta and BNY Trust Company of Canada.

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, 2007. Management and auditors' reports on the financial statements are dated February 25, 2008 and Management's Discussion and Analysis is dated February 25, 2008.

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 28, 2008. 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, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, 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, 2007.

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.	January 17, 2008	Canada	-	\$369,003,000	-	\$369,003,000
Totals			-	\$369,003,000	-	\$369,003,000

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 28, 2008

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, 2007 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 28, 2008

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 insure 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 affect 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.