FORTRESS ENERGY INC.

ANNUAL INFORMATION FORM

Year ended December 31, 2007

Dated March 31, 2008

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CONVENTIONS

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information with respect to the Corporation has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

ABBREVIATIONS

	Oil and Natural Gas Liquids		**Natural Gas**
Bbl	Barrel	Mcf	thousand cubic feet
Bbls	Barrels	MMcf	million cubic feet
MBbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMBbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	Million British thermal units
Bbls/d	barrels per day	Bcf	billion cubic feet
NGLs	natural gas liquids	GJ	Gigajoule

Other

AECO	Alberta Energy Company's natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
ºAPI	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28º API or higher is generally referred to as light crude oil
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices). BOE'S maybe misleading, particularly if used in isolation. A BOE conversion of 6 Mcf to 1Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/D	barrel of oil equivalent per day
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid is U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSION

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
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

DEFINITIONS

"ABCA" means the Business Corporations Act (Alberta), as amended;

"AIF" means this Annual Information Form;

"Board" means the Board of Directors of the Corporation as constituted from time to time;

"Business Day" means any day other than a Sunday, Saturday or a day on which banking institutions in Calgary, Alberta are authorized or obligated by law to close;

"COGE Handbook" means the "Canadian Oil and Gas Evaluation Handbook";

"Common Shares" means the common shares of the Corporation, as presently constituted;

"Fortress" means Fortress Energy Inc., a corporation incorporated under the ABCA;

"Goose River" means Goose River Resources Ltd.;

"Marauder" means Marauder Resources West Coast Inc.;

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

"Person" or "Persons" includes an individual, body corporate, partnership, syndicate or other form of unincorporated entity;

"Petroleum Properties" means a right, however derived, to explore for, develop, produce or market petroleum substances and include the lands associated with such right and includes as well any lease, permit, license, farm-in agreement, participation agreement, or other arrangement of whatsoever kind and any right to acquire the same;

"Predator" means Predator Exploration Ltd.;

"Principal Holder" means a person who, directly or indirectly, beneficially owns or controls 10% or more of any class of voting securities of the Corporation;

"PrivateCo" means a private oil and gas company acquired by the Corporation on January 26, 2005;

"Prospect" means drillable prospects or lands for farm-out in a geographical area in western Canada;

"Signal" means SignalEnergy Inc., a corporation incorporated under the laws of the Province of Quebec;

"Sproule" means Sproule Associates Limited, independent petroleum reservoir engineers, Calgary, Alberta; and

"Sproule Report" means the independent reserve analysis and report of the Corporation's reserves effective December 31, 2007 prepared by Sproule and dated March 6, 2008.

Unless the content otherwise requires, the "Corporation" when used in this Annual Information Form with respect to events occurring or matters as at a date prior to February 20, 2007 shall refer to Signal (the predecessor in interest of all of the assets of Fortress) and when used with respect to events occurring or matters as at a date from and after February 20, 2007 shall refer to Fortress.

Special Note Regarding Forward-looking Statements

Certain statements contained in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as “seek”, “anticipate”, “plan”, “continue”, “estimate”, “expect, “may”, “will”, “project”, “predict”, “potential”, “targeting”, “intend”, “could”, “might”, “should”, “believe” and similar expressions. 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. The Corporation believes that 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 in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by securities laws.

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

- oil and natural gas production levels;
- capital expenditure programs;
- the quantity of oil and natural gas reserves;
- projections of market 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 acquisitions, exploration and development; and
- treatment under governmental regulatory regimes.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors 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, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems; and
- fluctuations in foreign exchange or interest rates and stock market volatility; and
- change in government regulations.

These factors should not be considered exhaustive. The Corporation undertakes no obligation to publicly update or revise any forward-looking statements, except as required by securities laws.

CORPORATE STRUCTURE

Name, Address and Incorporation

Fortress Energy Inc. ("Fortress") a corporation incorporated under the ABCA, is the entity resulting from the reorganization of SignalEnergy Inc. ("Signal") on February 20, 2007.

A Reorganization (the "Reorganization") of Signal, including an arrangement (the "Arrangement") under the Companies Act (Quebec), was approved by the shareholders at a Special General Meeting of Shareholders held on February 15, 2007 and was effective February 20, 2007. Under the Arrangement, shareholders of Signal could elect to receive cash, common shares of Fortress, or a combination of both, subject to the cash amount being prorated in the event that shareholders elected to receive greater than $30 million. Shareholders representing 63,400,000 common shares of Signal elected to receive cash resulting in a cash distribution to shareholders of $30 million and the redemption of 23,076,923 common shares at a price of $1.30 per share. The remaining 66,539,059 common shares of Signal were exchanged for common shares of Fortress on the basis of one common share of Fortress for every five common shares of Signal, resulting in the issuance of 13,307,815 common shares of Fortress. Signal was then dissolved pursuant to the Companies Act (Québec) and Fortress became the holder of all of the assets formerly held by Signal.

Effective August 31, 2005, five subsidiaries of Signal, namely, Blairmore Energy Ltd., Goose River, PrivateCo, Nanodesign Inc. and Predator amalgamated by way of a horizontal short form amalgamation under the name Predator. Effective January 1, 2008 Fortress amalgamated, by way of a vertical short form amalgamation with its two subsidiaries Predator and Marauder. As a result Fortress has no subsidiaries.

The registered office of the Corporation is located at Suite 1500, 407 – 2nd Street S.W., Calgary, Alberta, T2P 2Y3, Canada. The Corporation has its head office in Calgary, Alberta located at 300, 505 – 3rd Street S.W., T2P 3E6.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

On January 20, 2005, the Corporation completed the acquisition of Predator, a publicly traded oil and gas corporation listed on the TSX Venture Exchange. The Corporation acquired all of the issued and outstanding shares of Predator in exchange for 10,424,097 Common Shares of the Corporation. Predator's main assets were producing natural gas properties in NE British Columbia and Kaybob in West Central Alberta. Predator had approximately 10,000 net acres of undeveloped land, with several drill ready prospects.

On January 26, 2005, the Corporation completed the purchase of all of the shares of PrivateCo for a purchase price of $4,100,000 and 1,000,000 Common Shares. PrivateCo's main assets were producing natural gas properties in the Chigwell region of Central Alberta.

Effective April 1, 2005, the Corporation sold its interest in the Twining area for cash proceeds of $13,250,000. This transaction closed on April 28, 2005. At the time of sale the Twining assets accounted for average production of approximately 170 BOE/D.

On August 9, 2005, the Corporation completed the acquisition of Goose River, a publicly traded oil and gas corporation listed on the TSX Venture Exchange. The Corporation acquired all of the issued and outstanding shares of Goose River in exchange for 21,250,000 Common Shares of the Corporation and cash costs of $11,771,490. Goose River's main assets are oil and natural gas properties in the Bodo, Bashaw and Redwater areas of Alberta.

Effective February 27, 2006 and March 9, 2006, the Corporation entered into an agreement with a private company to sell certain oil and gas properties, tangible equipment, and undeveloped land for net cash proceeds of approximately $91.2 million. The transaction involved the sale of the Corporation's interests in its Ferrier, Carrot Creek, Kaybob, Redwater and other minor properties, with the Corporation retaining its Chigwell/Bashaw and Buick Creek properties. The transaction closed in two stages on February 27, 2006 and March 10, 2006. In 2005, these properties accounted for gross petroleum and natural gas revenues of $17,365,000 and average daily production of approximately 850 BOE/D.

On November 15, 2006, the Corporation completed the acquisition of Marauder, a private oil and gas corporation. The Corporation acquired all of the issued and outstanding shares of Marauder in exchange for 16,349,534 Common Shares of the Corporation and cash costs of $16,660,210. Marauder's main assets are natural gas properties in the Ladyfern area of NE British Columbia and the Mearon area of NW Alberta.

On February 20, 2007 Signal completed the Reorganization. Signal was then dissolved pursuant to the *Companies Act (Québec)* and Fortress became the holder of all of the assets and liabilities formerly held by Signal.

The Corporation has entered into an agreement with an affiliate of AltaGas Income Trust ("AltaGas") that provides the Corporation with the option to construct a 38 km pipeline from a central point at its Square Creek, Alberta development area to the AltaGas processing facility at Clear Prairie. AltaGas will pay for 100% of the costs associated with the construction of the pipeline and in exchange the Corporation will dedicate a portion of its reserves in the Square Creek area and commit to a take-or-pay arrangement in respect of a smaller portion of such reserves until the pipeline costs have been recovered. The take-or-pay obligation provides that the Corporation will transport a minimum volume of natural gas through the pipeline and into the processing facility over a certain number of years. A volume commitment is also a component of this arrangement whereby the Corporation cannot terminate the processing portion of the arrangement until a certain reserve threshold has been met. The construction of the pipeline commenced in December, 2007 and is expected to cost approximately $8 million. The Corporation has active development plans for drilling wells in the Square Creek area in the first quarter of 2008.

NARRATIVE DESCRIPTION OF THE BUSINESS

General

Fortress is a Calgary based junior oil and gas exploration and development company operating in Western Canada.

PRINCIPAL PROPERTIES

The following property descriptions provide brief overviews of the Corporation's principal properties including an overview of operations conducted in 2007.

Buick Creek, British Columbia

The Buick Creek area is located approximately 75 kilometers northwest of Fort St. John, British Columbia and represents the Corporation's first property in northeastern B.C. In Buick Creek, the

Corporation holds an interest in 6,737 gross acres (6,038 net). The Corporation has an interest in 4 wells in this area.

The Buick Creek area produces from the Dunlevy formation (equivalent to the Lower Mannville Formation) and features long-life stable reserves with declines of 10-12% per year.

Operations in 2007 included stimulation of 2 wells which resulted in an increase in production late in 2007. Buick Creek contributed an average of 105 BOE/D of production in 2007 and is presently producing at 140 BOE/D.

Chigwell, Alberta

The Chigwell area is located approximately 75 km southeast of Edmonton, Alberta. The Chigwell property features multi-zone targets in the Edmonton, Belly River, Viking, Glauconite and Ellerslie formations at depths of 250 m for shallow Edmonton tests to 1800 m for Lower Mannville tests. The Corporation now holds an interest in 4,982 gross acres (3,841 net) in Chigwell.

Chigwell contributed an average of 17 BOE/D of production in 2007 and is not presently producing.

Bashaw, Alberta

The Bashaw area is located approximately 70 km south east of Edmonton, Alberta and is in close geographic proximity to the Chigwell property described above. Bashaw was the second major asset acquired in the Goose River acquisition and from a technical perspective is very similar to Chigwell featuring the same multi-zone targets with primary targets being the Edmonton sands and CBM, Belly River and Ostracod formations. The Corporation now holds an interest in 4,629 gross acres (2,198 net) in Bashaw. The Corporation has an interest in 20 wells in the Bashaw area.

The Bashaw assets are non-operated with Enerplus Resources Fund operating all of the Corporation's wells. During 2007, Bashaw contributed average production of 91 BOE/Dfor 2007 and is presently producing at 85 BOE/D.

Ladyfern North, British Columbia

The Ladyfern North area is located approximately 150 km northeast of Fort St. John, BC. At Ladyfern North, the Corporation holds an interest in 6,320 gross acres (5,910 net). The Corporation maintains a 100% working interest (and operatorship) in the producing portion of the property. The Corporation has an interest in 15 wells in this area.

The Ladyfern North area produces from the Notikewin formation (equivalent to the Upper Manville Formation) and features stable reserves with moderate declines of 15-20% per year.

Exploration and development targets in the Ladyfern area have typically focused on the Devonian Slave Point, Triassic Charlie Lake/Halfway and Cretaceous Bluesky/Gething formations. This previous deeper drilling has provided the necessary infrastructure with excess compression and pipeline capacity and also uncovered the uphole potential of the Cretaceous Notikewin sand.

There were no operations conducted at Ladyfern North by the Corporation in 2007. Ladyfern North contributed an average 209 BOE/D for 2007 and is presently producing at 175 BOE/D.

The Corporation's application for the implementation of Good Engineering Practice was approved on May 16, 2005. An application for Good Engineering Practice within a field or defined area is a routine practice amongst industry operators in the Province of British Columbia. Approval of any such application allows an operator to suspend target regulations, standard well spacing and density and individual production allowables (per well) within the application area. Presently the property is drilled to 2 wells per Drilling Spacing Unit ("DSU") on 6 DSUs, 3 wells per DSU on 1 DSU and 1 DSU has only 1 well on it. The Corporation has plans to down-space to a third Notikewin well on 6 DSUs in 2008.

The Corporation has reviewed its own proprietary 3D seismic and has selected an off-target Slave Point development well on its lands. This location is contingent on successful negotiations with the offset land owner to waive the off-target penalty factor and on future gas prices.

As a result of its drilling activity since the 2005-2006 operating season, Fortress has identified over 30 future development and appraisal drilling locations on the Ladyfern lands. These will be drilled to accelerate production as commodity prices permit.

Ladyfern South, British Columbia

The Ladyfern South area is located approximately 125 km northeast of Fort St. John, BC. At Ladyfern South, the Corporation holds an interest in 18,948 gross acres (11,342 net). The Corporation operates the property with EnCana Corporation as a joint venture partner. The Corporation has an interest in 14 wells in this area.

The Ladyfern South area produces predominantly from the Notikewin formation and features stable, long life reserves with moderate declines of 15-20% per year. In the fourth quarter of 2005, the Corporation signed a Farm-In Agreement with EnCana (the "EnCana Agreement") whereby it committed to drill 20 wells (prior to the exercise of certain rights of first refusal) during the 2006 and 2007 winter seasons to earn a 60% interest in 40 Drilling Spacing Units (DSUs).

Operations conducted by the Corporation in 2007 included drilling 5 gross wells Ladyfern South contributed an average 194 BOE/D for 2007 and is presently producing at 157 BOED.

Good Engineering Practice was applied for by EnCana Corporation and approval was received on June 20, 2005. Presently the property is developed at less than normal spacing (1 well per DSU). The Corporation has fulfilled its earning commitments under the EnCana Agreement. Future plans include 6 recompletion operations of EnCana wellbores close to existing infrastructure. The Corporation also has plans to down-space to a second and third well on the earned lands with 22 Notikewin locations planned for 2008 and 13 Notikewin locations planned for 2009.

Velma, British Columbia

The Velma area is located approximately 400 km northeast of Fort St. John, BC. At Velma, the Corporation holds an interest in 8,431 gross acres (6,614 net). The Corporation maintains a 100% working interest (and operates) the producing portion of the property. The Corporation has a 100% working interest in two wells in this area.

The Velma area produces from the Bluesky formation and features stable reserves with moderate declines of 15-20% per year.

Operations conducted by the Corporation in 2007 included installing a separation and sweetening facility Velma contributed an average 150 BOE/D for 2007 and is presently producing at 380 BOED.

In addition to the producing Bluesky wells, Fortress has identified 12 future development locations in the shallower Notikewin Formation. As is the case with Ladyfern South, these development locations will be drilled when supported by commodity prices with the primary purpose of mitigating expected production declines in the area.

Mearon, Alberta

The Mearon North area is located approximately 175 km northeast of Fort St. John, BC. Mearon North sits immediately east of the Ladyfern North property across the border in NW Alberta. At Mearon North, the Corporation holds an interest in 20,269 gross acres (15,725 net). The Corporation maintains a 100% working interest and operates the producing portion of the property. The Corporation has an interest in 14 wells in this area.

The Mearon North area produces from the Notikewin formation (equivalent to Upper Manville) and features stable reserves with moderate declines of 15-20% per year.

There were no operations conducted by the Corporation in 2007. Mearon North contributed an average 240 BOE/D for 2007 and is presently producing at 300 BOE/D.

A Holding was approved by the Alberta Energy and Utilities Board on December 6, 2006 permitting the drilling of a second Notikewin well per section. An application to implement a Holding within a field or defined area is a routine practice amongst operators in the Province of Alberta. The approval of any such application permits the operator to suspend target regulations, alter standard well density and the inter-well distance between producing wells within the application area.   Operations conducted in Q1 of 2007 included the drilling of 5 new wells, all of which were tied in to production facilities.

Square Creek, Alberta

The Square Creek area lies 150 kilometres northeast of Fort St. John and 50 kilometres east of the Alberta- B.C. border. Fortress is the operator of the property and currently holds working interests ranging from 50 percent to 100 percent in approximately 32,000 gross acres of land. The Corporation obtained its interest through a joint venture farm-in with a senior oil and natural gas producer that was entered into by a predecessor of the Corporation.

Square Creek contains a mixture of exploratory, appraisal and development drilling opportunities. Principal targets are the Cretaceous Bluesky and shallower Notikewin formations. Drilling depths in the area vary from 700 metres to 1,200 metres depending on the target Formation.

Fortress has identified two future Bluesky development drilling locations and five future Notikewin drilling locations on the Square Creek area lands.

In 2007, the Corporation initiated farm-in obligations by completing one well and drilling two others, all successful operations. In addition, the Corporation proved up three new gas wells as a result of the aforementioned activities and confirmed the commercial viability of the Notikewin formation. Combined initial flow rates from the Bluesky and Notikewin zones were in excess of 7.1 MMcf/d gross.

During the first quarter of 2008, Fortress operated the drilling of 5 gross wells (3 net), tied-in 7 wells (6 producing wells plus one water disposal well), constructed local central facilities as well as a 41-kilometre pipeline from the property to a processing facility owned and operated by a third-party midstream services.

Land Holdings

The following table sets out the developed and undeveloped land holdings of the Corporation as at December 31, 2007.

	Developed		**Undeveloped**		**Total**		**Net Area to Expire 2008**
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	
Alberta	13,482	9,084	79,759	64,680	93,241	73,764	5,544
B.C.	20,060	16,073	30,020	22,331	50,080	38,404	4,013
Total	33,542	25,157	109,779	87,011	143,321	112,168	9,557

Notes:
(1) "Gross" refers to the total acres in which the Corporation has an interest.
(2) "Net" refers to the total acres in which the Corporation has an interest, multiplied by the percentage working interest therein owned by the Corporation.

Land Evaluation

An independent land evaluation dated as at December 31, 2007 was completed by Independent Land Evaluations Inc. resulting in an undeveloped land total net value of $19,132,243.

RESERVE ESTIMATES

Sproule Report

The following tables set forth certain information relating to the oil and natural gas reserves of the Corporation's properties and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2007 and have been made assuming that development of each property in respect of which the estimate is made will occur, without regard to the likely availability of funding required for that development. Abandonment costs vary per well from $20,000 to $30,000 and were included in the Sproule Report. The information set forth below is derived from the Sproule Report which has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment and disconnect costs for all of the Corporation's wells assigned reserves. No allowances for reclamation, salvage values or production facilities were made. 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 Sproule represent 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 the Corporation'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 Sproule Report is based on certain factual data supplied by the Corporation and Sproule's opinion of reasonable practice in the industry. 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) were supplied by us to Sproule and accepted without any further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

The Corporation's Board of Directors reviews the qualifications, and appointment of the independent qualified reserves evaluators. The Board also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluation and review by the independent qualified reserves evaluators.

Reserves presented are 100% of the reserves attributable to the Corporation and its consolidated subsidiaries. All of the properties, reserves and production of the Corporation are located in Canada in the provinces of Alberta and British Columbia.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101 F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101 F3 are attached as Schedules A and B hereto, respectively.

Summary of Oil and Gas Reserves – Forecast Prices and Costs

Summary of Oil and Gas Reserves
As of December 31, 2007
Forecast Prices and Costs

	Reserves					
	Light/Medium Oil (MBbl)		Natural Gas (MMcf)		NGL (MBbl)	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	-	-	11,419	9,633	68.6	54.9
Developed Non-Producing	-	-	1,433	1,376	-	-
Undeveloped	-	-	11,354	9,617	5.2	4.2
Total Proved	-	-	24,206	20,626	73.8	59.1
Probable	-	-	13,919	12,347	28.1	22.5
Total Proved plus Probable	-	-	38,125	32,973	101.9	81.6

Summary of Net Present Values of Future Net Revenue
As of December 31, 2007
Forecast Prices and Costs

	Before Income Tax Discounted At					**After Income Tax Discounted At**					**Unit Value $/BOE Net Reserves Discounted at 10% before Income Tax**
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	($/BOE)
Proved											
Developed Producing	40,820	34,417	29,955	26,651	24,097	40,820	34,417	29,955	26,651	24,097	18.04
Developed Non-Producing	3,785	3,148	2,666	2,291	1,992	3,785	3,148	2,666	2,291	1,992	11.62
Undeveloped	32,840	24,206	18,601	14,657	11,732	32,840	24,206	18,601	14,657	11,732	11.57
Total Proved	77,445	61,771	51,223	43,599	37,821	77,445	61,771	51,223	43,599	37,821	14.65
Probable	49,375	35,602	26,847	20,860	16,570	38,286	27,803	21,107	16,500	13,179	12.91
Total Proved plus Probable	126,819	97,373	78,070	64,459	54,390	115,731	89,574	72,330	60,099	51,000	14.00

Notes:
(1) The Sproule Report estimates Fortress' share of future capital expenditures necessary to achieve the estimated present worth of future net cash flows based on escalating costs from Proved Reserves to be $16,435,000 and Proved and Probable Reserves to be $26,824,000.

Future Net Revenue - Forecast Prices and Costs

The following table sets forth the following elements of future net revenue attributed to Proved Reserves and Proved plus Probable Reserves of the Corporation as of December 31, 2007 estimated based on forecast prices and costs and calculated without discount

Total Future Net Revenue
(Undiscounted)
As of December 31, 2007
Forecast Prices and Costs

Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Capital Development Costs (M$)**	**Well Abandonment Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**	**Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
Proved	187,587	24,621	66,941	16,435	2,146	77,445	-	77,445
Proved plus Probable	298,405	36,221	105,649	26,824	2,891	126,819	11,089	115,731

The following table set forth the future net revenue (before deducting future income tax expenses) of the Corporation as of December 31, 2007 estimated based on forecast prices and costs and calculated using a discount rate of 10 percent:

Net Present Value of Future Net Revenue by Production Group
As of December 31, 2007
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%) (M$)	Future Net Revenue Before Income Taxes (discounted at 10%) ($/BOE)
Proved	Light/Medium Oil	-	-
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)	51,223	14.65
	TOTAL	51,223	14.65
Proved plus Probable	Light/Medium Oil	-	-
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)	78,070	14.00
	TOTAL	78,070	14.00

Note: (1) Columns may not add due to rounding.

Pricing Assumptions

The escalating cost and price assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating capital costs. In the Sproule Report operating costs are assumed to escalate at 2% per annum. Crude oil and natural gas base case prices as forecasted by Sproule Report effective January 1, 2008 are as follows:

Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Cromer Medium 29.3 API ($Cdn/Bbl)	Natural Gas [1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/Bbl)	Butanes F.O.B. Field Gate ($Cdn/Bbl)	Inflation Rate[2] (%/Yr)	Exchange Rate[3] ($US/$Cdn)
Historical								
2007	72.27	77.06	65.33	6.65	77.30	63.71	2.0	0.935
Forecast								
2008	89.61	88.17	75.83	6.51	90.30	65.72	2.0	1.000
2009	86.01	84.54	72.71	7.22	86.58	63.01	2.0	1.000
2010	84.65	83.16	71.52	7.69	85.17	61.98	2.0	1.000
2011	82.77	81.26	69.89	7.70	83.23	60.57	2.0	1.000
2012	82.26	80.73	69.43	7.61	82.68	60.17	2.0	1.000
Thereafter	Various Escalation Rates							

Notes:
(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

Note: Product sale prices will reflect those reference prices with further adjustments for quality and transportation to point of sale.

The weighted average prices received by the Corporation for 2007 were: Natural Gas - $6.32/Mcf; Oil and Natural Gas Liquids - $68.15/Bbl.

Definitions Applicable to Reserves Tables

"Gross" means the Corporation's total working interest share before deducting royalties and without including any royalty interest of Signal.

"Net" means the Corporation's total working interest and/or royalty interest share after deducting the amounts attributable to royalties owned by others.

"Royalties" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

"Reserves" are the 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: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"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.

"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.

"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.

"Undeveloped" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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, probable, possible) to which they are assigned.

"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.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following table sets forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation:

Year	Undeveloped Reserves	Light and Medium Oil (MBbls)	Heavy Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	MBOE
2004	Proved Undeveloped Reserves	-	-	540	-	90.0
2005	Proved Undeveloped Reserves	43.2	-	1,974	12.4	384.6
2006	Proved Undeveloped Reserves	-	-	7,101	-	1,183.5
2007	Proved Undeveloped Reserves	-	-	11,354	5.2	1,897.5
2004	Probable Undeveloped Reserves	13.0	-	2,790	101.0	579.0
2005	Probable Undeveloped Reserves	624.7	4.1	7,977	151.0	2,109.2
2006	Probable Undeveloped Reserves	1.8	-	5,692	14.5	965.0
2007	Probable Undeveloped Reserves	-	-	9,701	13.0	1,629.8

In general, undeveloped reserves of the Principal Properties of the Corporation are scheduled to be developed within the next two years. See "Principal Properties" for general development plans of the Corporation.

Significant Factors or Uncertainties Affecting Reserves Data

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Corporation. The reserve data included or incorporated by reference herein represents estimates only.

In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Corporation with respect to these reserves will vary from such estimates, and such variances could be material.

Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves.

Consistent with the securities disclosure legislation and policies of Canada, as interpreted by the securities regulatory authorities in Canada, the Corporation has used forecast prices and costs in calculating reserve quantities included herein. Actual future net cash flows also will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below.

Year	Forecast Prices and Costs (undiscounted)	
	Proved (M$)	Proven plus Probable (M$)
2008	8,386	9,862
2009	6,228	10,283
2010	1,820	6,679
Total	16,435	26,824

The source of funding for future development costs of the reserves of the Corporation will be derived from a combination of funds from operations, debt and new equity. Management does not anticipate that the costs of funding, referred to above, will materially affect the disclosed reserves and future net revenues of the Corporation or will make the development of any of the properties uneconomic.

RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

The following table sets out the reconciliation of changes in Gross Reserves (3) (before Royalty) by Principal Product Type for the period from December 31, 2006 to December 31, 2007 using forecast prices and costs:

	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas (1)			Natural Gas Liquids		
Factors	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)
December 31, 2006	6.2	2.9	9.1	-	-	-	16,804	8,428	25,232	56.0	25.7	81.7
Extensions	-	-	-	-	-	-	2,820	1,393	4,213	5.2	0.7	5.9
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	(1,302)	223	(1,079)	17.6	4.7	22.3
Discoveries	-	-	-	-	-	-	2,353	627	2,980	-	-	-
Acquisitions (1)	-	-	-	-	-	-	5,562	3,002	8,564	18.0	3.3	21.3
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(5.9)	(2.9)	(8.8)	-	-	-	233	246	479	(9.8)	(6.3)	(16.1)
Production (2)	(0.3)	-	(0.3)	-	-	-	(2,263)	-	(2,263)	(13.2)	-	(13.2)
December 31, 2007	-	-	-	-	-	-	24,207	13,919	38,125	73.8	28.1	101.9

Notes:

(1) Includes solution gas.

(2) Fortress has no unconventional reserves (Bitumen, Synthetic Crude Oil, etc.)

(3) Gross Reserves means the Corporation's working interest reserves before calculation of royalties, and before consideration of the Corporation's royalty interests.

OTHER OIL AND GAS INFORMATION

Oil and Gas Wells

The following table summarizes the Corporation's interest as at December 31, 2007 in wells, which are producing, or which the Corporation considers to be capable of production.

Alberta	Gross[1]		Net[2]	
	Producing	**Shut-in**[3]	**Producing**	**Shut-in**[3]
Oil	-	-	-	-
Gas	42	13	40	11
Total	42	13	40	11
British Columbia				
Oil	-	-	-	-
Gas	43	13	41.5	11.5
Total	43	13	41.5	11.5

Notes:

(1) "Gross" refers to all wells in which the Corporation has an interest.
(2) "Net" wells refer to the total number of wells in which the Corporation has an interest multiplied by the Corporation's percentage working interest therein.
(3) "Shut-in" wells are defined as wells which have encountered crude oil or natural gas and are capable of producing crude oil or natural gas but which are not producing due to the lack of transportation facilities, available markets or other reasons.

The majority of the Corporation's shut-in wells and booked reserves are in the Ladyfern North & South, and Mearon North areas. Compression was installed in the Ladyfern North property in the first quarter of 2008, and is expected to be on line around mid April. The goal of this compression is to lower the pipeline pressures and resulting in greater velocities up the tubing strings on the affected wells. This will allow the wells to lift water more effectively and maintain the projected production declines. Once the compressor station is on line, the Corporation's plan is to start up any shut in wells in hopes that with the lower pipeline pressures will allow these wells to produce again.

If this plan is successful in Ladyfern North, then the same philosophy will be applied in the Mearon North and Ladyfern South properties. If the plan is unsuccessful then any shut-in wells will be put on a list for abandonment in the following winter. In the Buick Creek area all of the wells were worked over and stimulated in the fourth quarter of 2007. This program was successful in all but two wells. The remaining two wells will need to be abandoned in the following winter. In the Chigwell area the Corporation is unable to produce most of the wells due to high pipeline pressures. Currently the economics will not support field compression, however this property is currently being review from a geological perspective and may yield future opportunities and support the economics to provide compression.

The majority of PUD reserves are in the Ladyfern South area. Up to 40 additional drilling locations have been identified to convert the PUD reserves to PDP. A drilling program in the Ladyfern South area is very sensitive to gas prices, and if the prices are strong in 2009 then a drilling program will be initiated.

Forward Contracts

The Corporation uses commodity contracts to manage its exposure to fluctuations in the price of natural gas. In 2007, the Corporation recorded realized gains on commodity contracts of $393,000 or $1.09/BOE (2006 - $nil) and an unrealized gain of $92,000 or $0.25/BOE.

The following commodity contracts are in place as at December 31, 2007:

Type	Period	Volume (GJ/d)	Fixed Price ($/GJ)
Swap	January 1, 2008 to October 31, 2008	2,000	6.51
Swap	January 1, 2008 to October 31, 2008	3,000	6.505

Additional information concerning Abandonment and Reclamation Costs

The Corporation is liable for its share of the ultimate reclamation of the working interest properties upon abandonment. The Corporation has created a liability for existing asset retirement obligations. The discounted amount recognized during 2007 was $3,050,000. The undiscounted estimated cash flows required to settle the obligation is $4.8 million net of salvage value. The expected timing of payment ranges between three to twelve years and applies a 7.5% credit-adjusted risk-free rate. Due to use of management estimates in determining asset obligation liability, actual results could differ from those reported. The Corporation expects to abandon and reclaim approximately 10 wells within the next three years at an estimated abandonment cost of approximately $500,000. The asset retirement obligation recorded in the Corporation's consolidated balance sheet at December 31, 2007 exceeds that used in the Sproule Report by $159,000 because the Sproule Report makes no allowances for reclamation or production facilities.

Tax Horizon

The Corporation recorded a recovery of future income taxes for the year ended December 31, 2007 of $2,715,000 compared to future income tax expense of $36,000 in 2006. Future income tax reflects the difference between the underlying tax value and carrying value of the Company's assets and liabilities. The change in future income taxes reflects the sale of oil and gas assets in the first quarter of 2006 and the application of available tax pools to minimize the tax liability to the Company. Based in current commodity prices and planned capital expenditures, the Corporation does not expect to be cash taxable in 2008.

The income tax effect of a $5 million flow-through share offering completed in December 2007 will be recorded in the first quarter of 2008 with the filing of the renouncement documents to the taxation authorities. The effective date of the renouncement was December 31, 2007 with all expenditures to be incurred by December 31, 2008.

The estimated tax pools of the Corporation at December 31, 2007 are as follows:

	(M$)
Canadian Oil and Gas Property Expenses	14,790
Canadian Development Expenses	26,931
Canadian Exploration Expenses	15,307
Undepreciated Capital Cost	28,788
Share issuance costs	922
Investment Tax Credits	2,367
Non-capital losses	210
	89,315

For further details regarding income taxes, refer to the Corporations Management Discussion and Analysis and Annual Financial Statements as at and for the year ended December 31, 2007 filed on SEDAR at www.sedar.com.

Costs Incurred

The following table summarizes capital expenditures net of certain proceeds and including capitalized general and administrative expenses related to the Corporation's activities for the years ended December 31, 2007 and 2006:

	Year ended December 31,	
	2007 (M$)	2006 (M$)
Land and seismic	232	94
Drilling and completions	11,696	1,343
Equipment and facilities	10,873	2,293
Property acquisitions	12,963	720
Capitalized overhead costs	1,309	410
Other	1,377	126
	38,450	4,986

Total capital expenditures for 2007 were $38,450,000 compared to $4,986,000 in 2006. The Corporation's initial capital program was $15,000,000 which was allocated to the first quarter drilling program which focused exclusively on the Company's lands in the Ladyfern, Mearon, Square Creek, and Drake areas. The Corporation drilled a total of 14 gross (8 net) wells of which 11 gross (6.5 net) were considered to be development wells and 3 gross (1.5 net) were exploratory. In addition, the Corporation completed 7 recompletion operations existing wells. A total of 8 gross (4.5 net) wells were tied into production facilities in the first quarter of which 1 gross (0.5 net) wells were from Marauder's 2006 drilling program. The wells that were tied to production facilities in the first quarter of 2007 added incremental production of 200 BOE/D. The 2007 drilling program also set up an additional 20 development and 6-8 exploratory drilling opportunities for 2008. In the first nine months of 2006, the Corporation was not actively engaged in exploration or development opportunities due to the sale of oil and gas assets.

The capital program was expanded in the third quarter to include the acquisition of a partner's working interests in the Ladyfern, Mearon and Velma areas for cash of $12.5 million. The acquisition included approximately 250 BOE/D of natural gas production with additional production behind pipe, estimated reserves of 1.0 MMBOE on a proven basis and 1.5 million BOE on a proven plus probable basis, and 54,232 net acres of undeveloped land. The Corporation also completed the installation of its refrigeration plant at Ladyfern to improve the recovery of natural gas liquids and to lower the dew point of the gas entering the third-party processing facility. The plant came on production in late August and is expected to provide greater reliability of processing capabilities and generate additional processing revenues for the Company. The Corporation also completed the surface facilities and the tie-in of two wells at Velma which came on production in late August.

The Corporation's planned capital expenditures for 2008 is $8.1 million, most of which is expected to be incurred in the first quarter and is focused on the Company's Square Creek development area in Alberta.

Commitments

Royalties

The Company will pay to various university research centers royalties amounting to two – five percent on sales of licensed products related to a research contract and acquired technology rights and 15% of sublicense revenues from products related to the acquired technology rights. At December 31, 2007 and 2006, there were no royalties payable under these agreements.

Office space and equipment

The Company is committed to minimum annual lease payments under operating leases for office premises and office equipment to March, 2013, as follows:

	(M$)
2008	431
2009	430
2010	435
2011	439
Thereafter	549
	2,284

Transportation and Processing

On November 27, 2007, the Company entered into an agreement with an affiliate of AltaGas Income Trust ("AltaGas") for the transportation and processing of natural gas from the Company's Square Creek, Alberta area. The agreement requires the Company to construct a 38km pipeline from a central point in the Square Creek development area to the AltaGas processing facility at Clear Prairie to enable the delivery and sale of natural gas. Upon commissioning of the pipeline, which is expected in early April 2008, AltaGas has agreed to purchase the pipeline from the Company. In exchange, the Company has committed to pay the greater of a fee calculated as monthly volumes at an established rate per mcf, or an established minimum monthly processing fee based on estimated gas throughput of 2 mmcf per day until the costs of the pipeline have been recovered, at which time the Company will pay a reduced monthly processing fee until the earlier of April 1, 2015 or the delivery of a total of 15 bcf.

Committed payments are as follows:

	(M$)
2008	949
2009	1,260
2010	1,052
2011	767
2012	767
Thereafter	1,605
	6,400

The Company's joint interest partner in the Square Creek area has agreed to be responsible for all terms and conditions of the agreement related to their 50% working interest in this area. Committed payments, as noted above, represent only the Company's 50% working interest.

Drilling Commitments

As at December 31, 2007, the Company had committed to drill a well in the Square Creek area pursuant to a farm-in agreement, at an estimated cost of $650,000. In January, 2008, the Company drilled this well and satisfied the terms of the agreement.

Guarantees

The Company maintains liability insurance for its directors and officers and indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Company to the extent permitted by law.

Claims and Litigation

The Company is involved in various claims and litigation arising in the normal course of business. The outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favor. If the outcome is unfavorable, it could have a materially adverse impact on the Company's financial position or results of operations.

Letter of Credit

Subsequent to December 31, 2007, the Company issued a letter of guarantee for $1,000,000 with an expiry of February 1, 2009, related to a gas transportation and processing agreement

Exploration and Development Activities

Drilling Activity

During the twelve month period ending December 31, 2007, the Corporation drilled 14 gross (7.8 net) wells resulting in 12 gross (6.3 net) producing wells:

Year Ended December 31, 2007	Crude Oil		Natural Gas		Suspended		Service		Dry		Total
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Net
Exploratory	-	-	2.0	2.0	-	-	-	-	1.0	1.0	2.0
Development	-	-	10.0	5.3	-	-	-	-	1.0	0.5	5.8

For a description of the Corporation's intended exploration and development activities see the description under "*Principal Properties*".

Estimated 2008 Production Volumes

The following table provides the volume of production of the Corporation estimated for 2008 for its reserves:

	Forecast Prices and Costs (undiscounted)	
	Proved Reserves	Proved plus Probable Reserves
2008 Production (Gross)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	3,755	4,070
Natural Gas Liquids (MBbl)	0.4	0.4
Oil equivalent (MBOE)	626.2	678.7
2008 Production (Net)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	2,953	3,181
Natural Gas Liquids (MBbl)	0.3	0.3
Oil equivalent (MBOE)	492.5	530.5

Production History for 2007

Daily Sales Volumes and Netback

The following table sets forth the sales volumes and netbacks attributable to the Corporation's oil and gas assets on a quarterly basis for the periods indicated:

		Average per Unit of Volume			
	Production Volume (Bbls or Mcf)	**Price ($/Bbl or Mcf)**	**Royalties ($/Bbls or Mcf)**	**Costs ($/Bbls or Mcf)**	**Netback [1] ($/Bbls or Mcf)**
Light & Medium Oil (Bbls) [2]					
First Quarter	-	-	-	-	-
Second Quarter	-	-	-	-	-
Third Quarter	-	-	-	-	-
Fourth Quarter	-	-	-	-	-
Natural Gas (Mcf)					
First Quarter	422,936	7.47	1.03	1.47	4.97
Second Quarter	462,529	7.07	1.02	1.37	4.68
Third Quarter	562,243	5.53	0.50	1.71	3.32
Fourth Quarter	685,821	6.49	1.93	2.54	2.02
Natural Gas Liquids (Bbls)					
First Quarter	1,992	60.56	36.71	8.82	15.03
Second Quarter	2,206	52.14	4.70	8.23	39.21
Third Quarter	611	71.42	158.61	10.31	(97.50)
Fourth Quarter	1,168	86.95	10.88	15.26	60.81
Light & Medium Oil & Natural Gas Liquids Combined (Bbls)					
First Quarter	72,481	45.48	6.99	8.82	29.67
Second Quarter	79,294	42.75	6.07	8.23	28.45
Third Quarter	94,318	33.44	4.03	10.31	19.10
Fourth Quarter	115,472	38.37	10.88	15.26	12.23

Notes:

(1) Netback is calculated as price realized by the Corporation (net of transportation costs and including realized gains on commodity contracts), less royalties, and less operating costs.

(2) The Corporation had substantially no light and medium oil production in 2007.

FURTHER DESCRIPTION OF THE BUSINESS

Employees

As of December 31, 2007, the Corporation had 11 employees and 8 consultants.

Competitive Conditions

The Corporation actively competes for reserve acquisitions, exploration leases, licenses 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 individual producers and operators.

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.

Certain of the Corporation's customers and potential customers are themselves 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 in the future. The Corporation's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment

Business Cycle and Seasonality

The Corporation's business is generally not cyclical; however its revenue from the sale of natural gas is highly seasonal, with demand for natural gas rising during cold winter months and hot summer months. Access to the Corporation's properties for exploration and development activities is restricted to the winter months. Any unreasonable winter temperatures could adversely affect the Corporation's drilling activities.

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.

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 international conventions and federal, 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 natural 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 foreign governments and third parties and may require the Corporation to incur costs to remedy such discharge. 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, results of operations or prospects.

RISK FACTORS RELATING TO THE OIL AND GAS BUSINESS

Alberta Royalty Rate Changes

The increased royalties payable to the Alberta government pursuant to its new royalty regime announced on October 25, 2007 may negatively impact the net cash flow of the Corporation. The actual effect on the Corporation will depend upon the actual legislation enacted, production rates, commodity prices, foreign exchange rates, production mix and service costs as they exist on January 1, 2009.

Significant Factors or Uncertainties Affecting Reserves Data

See "*Other Oil and Gas Information – Significant Factors or Uncertainties Affecting Reserves Data*".

Competitive Conditions

See "*Further Description of the Business – Competitive Conditions*".

Business Cycle and Seasonality

See "*Further Description of the Business – Business Cycle and Seasonality*".

Environmental Protection Requirements

See "*Further Description of the Business – Environmental Protection Requirements*".

Volatility of Oil and Natural Gas Prices

The results of operations and financial condition are dependent on the prices received for the Corporation's oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond the Corporation's control. These factors include, but are not limited to, worldwide political instability, foreign supply of oil and natural gas, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels and the overall economic environment. Any decline in oil or natural gas prices could have a material adverse effect on the Corporation's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves. No assurance can be given that oil and natural gas prices will be at levels which will generate profits for the Corporation.

Need to Replace Reserves

The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, are highly dependent upon the Corporation's success in exploring its current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. In addition, there can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

Operating Hazards and Other Uncertainties

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. Although the Corporation maintains insurance in accordance with customary industry practice, the Corporation is not fully insured against all of these risks. Losses resulting from the occurrence of these risks could have a material adverse impact on us. Like other oil and natural gas companies, the Corporation attempts to conduct its business and financial affairs so as to protect against political and economic risks applicable to operations in the jurisdictions where the Corporation operates but there can be no assurance that the Corporation will be successful in so protecting itself.

The Corporation is also subject to deliverability uncertainties related to the proximity of its reserves to pipeline and processing facilities and the possible inability to secure space on pipelines, which deliver oil and natural gas to commercial markets.

Debt Service

The Corporation completed a reorganization in the first quarter of 2007, which included an arrangement whereby the Corporation distributed Common Shares and cash of $30 million to its shareholders. The Corporation has fully utilized its currently available operating credit facilities to finance the balance of its 2007 capital program and a $12.5 million asset acquisition. The Corporation has experienced positive cash flows from operations for 2007. The ability of the Corporation to meet its debt service obligations will depend on the future operating performance and financial results of the Corporation, which will be primarily subject to factors beyond its control. If it is unable to obtain sufficient cash to service its debt, it may be required to refinance all or a portion of its debt, obtain additional financing or sell certain of its assets. There can be no assurance that any such refinancing would be possible or that any additional financing could be obtained on acceptable terms, nor can there by any assurance as to the timing of any such asset sales or the proceeds which could be realized therefrom.

Acquisition Risks

The Corporation intends to continue acquiring oil and natural gas properties. Although the Corporation performs a review of the acquired properties that the Corporation believes is consistent with industry practices, it generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, the Corporation will focus its review efforts on the higher-value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal every existing or potential problem, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Corporation often assume certain environmental and other risks and liabilities in connection with acquired properties. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and actual future production rates and associated costs with respect to acquired properties, and actual results may vary substantially from those assumed in the estimates.

Kyoto Protocol

The Kyoto Protocol came into effect on February 16, 2005. As yet, however, no specific details regarding its implementation in Canada have been made by the Federal Government. The Kyoto Protocol was established to set legally binding targets to reduce emissions of carbon dioxide, methane, nitrous oxide and other so-called “greenhouse gases”. The Corporation’s exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject us to legislation regulating emissions of greenhouse gases. Numerous uncertainties regarding details of the Kyoto Protocol’s implementation remain that make it difficult to ascertain the cost estimate, including when third party costs related to the Kyoto Protocol factor their way into the Corporation’s supply chain of goods and services. There is no assurance that the cost impact to the Corporation of the Kyoto

Protocol or subsequent legislation related to the Kyoto Protocol will not be significant, which could result in a material adverse effect on the Corporation's financial condition or results of operations. Future federal legislation, together with provincial emission reduction requirements, may require the reduction of emissions or emissions intensity produced by the Corporation's operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of the Corporation.

Governmental Regulation

The oil and natural gas business is subject to regulation and intervention by governments in such matters as the awarding of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Such regulation may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas, increase the Corporation's costs and have a material adverse impact on us.

Sale of Additional Common Shares

The Corporation may issue an unlimited number of additional Common Shares in the future to finance its activities without the approval of shareholders. The Board has the discretion to set the price and terms of the issuance of any such additional Common Shares and any issuance of additional Common Shares may have a dilutive effect on the holders of Common Shares.

DIVIDENDS

No cash dividends have been declared by the Corporation in respect of any class of the Corporation's shares for any of the three most recently completed financial years. The Corporation does not currently have a policy of paying dividends.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value, of which 15,986,888 were issued and outstanding as at the date hereof as fully paid and non-assessable.

The holders of the Common Shares are entitled to dividends as and when declared by the Board of Directors, to one vote per share at meetings of shareholders of the Corporation and, upon liquidation, to receive such assets of the Corporation as are distributable to the holders of the Common Shares.

Preferred Shares

The Corporation is authorized to issue an unlimited number of preferred shares without nominal or par value (the "Preferred Shares") issuable in series. No series of Preferred Shares have been created and there are no Preferred Shares outstanding.

The Preferred Shares shall be entitled to preference over the Common Shares of the Corporation and over any other shares ranking junior to the Preferred Shares with respect to distribution of assets in the event of liquidation, dissolution or winding-up of the Corporation.

MARKET FOR SECURITIES

The Common Shares of Fortress are listed and posted for trading on The Toronto Stock Exchange under the symbol FEI. In 2007 there were 5,708,900 Fortress common shares traded at prices ranging from a low of $1.02 to a high of $3.94.

	Volume	High ($)	Low ($)	Close ($)
January 2007(1)	6,831,900	0.99	0.87	0.90
February 2007(1)	3,896,900	0.95	0.73	0.79
March 2007	585,000	3.94	2.75	2.92
April 2007	681,200	3.20	2.85	3.01
May 2007	1,004,000	3.46	2.91	3.19
June 2007	935,500	3.27	3.00	3.09
July 2007	171,200	3.35	2.66	2.75
August 2007	225,300	2.85	1.62	2.24
September 2007	79,300	2.20	1.76	1.80
October 2007	451,600	1.94	1.51	1.56
November 2007	186,200	1.76	1.34	1.35
December 2007	1,389,600	1.44	1.02	1.13
January 2008	98,500	1.40	1.14	1.29
February 2008	87,600	1.70	1.29	1.61

Notes

(1) Represents the shares of Signal traded. On February 20, 2007, the Reorganization was effected resulting in the redemption of 23,076,923 Signal common shares and the exchange of 66,539,059 Signal common shares for 13,307,815 Common Shares of Fortress.

ESCROWED SECURITIES

There were no escrowed securities as at December 31, 2007.

DIRECTORS AND OFFICERS

The name, occupation and security holdings of each of the directors and senior officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held with Fortress	Year First Appointed	Present Occupation During the Last Five Years	Fortress Shares Beneficially Owned
J. CAMERON BAILEY Calgary, Alberta	President and Chief Executive Officer and Director	2003	President and Chief Executive Officer, of Fortress (formerly Signal) Prior thereto, Managing Director of Network Capital Inc., a private investment firm from December 1999	369,980
RICHARD GRAFTON(1) Calgary, Alberta	Director	2008	President and Chief Executive Officer, Grafton Capital Corporation Prior thereto, Vice-Chairman of Canaccord Capital Prior thereto, Managing Director and a Founding Shareholder of FirstEnergy Capital Corp.	-

Name and Municipality of Residence	Position Held with Fortress	Year First Appointed	Present Occupation During the Last Five Years	Fortress Shares Beneficially Owned
GEORGE WATSON(1) (2) Calgary, Alberta	Director	2003	Chief Executive Officer of Critical Control Solutions Inc., a public technology company, since January, 2000. Prior thereto, President and Chief Executive Officer of TransCanada Pipelines Ltd.	30,938
WILL FRANKLIN (1) Houston, TX	Director	2007	Director of Lime Rock Partners since 2003 Prior thereto, Associate at Riverstone Holdings	-
JOHN CLARKSON(2) Cochrane, Alberta	Director	2007	Independent businessman since 2007 Prior thereto, Managing Director of Lime Rock Management Ltd. since 2003 Prior thereto, Managing Director of Clearwater Capital Corporation	-
DONALD LEITCH Calgary, Alberta	Director	2007	Partner, Carscallen Leitch LLP	-
DARREN JACKSON Calgary, Alberta	Vice-President, Operations and Chief Operating Officer	2007	Vice President Operations, Chief Operating Officer of Fortress Prior thereto,	32,829
JAMIE JEFFS Calgary, Alberta	Vice President, Finance and Chief Financial Officer	2005	Vice President, Finance and Chief Financial Officer of Fortress (formerly Signal) Prior thereto, Vice President, Finance, of CriticalControl Solutions Corp. from June 2002 to July 2005 Prior thereto, Director, Finance of VeriticalBuilder.com Inc. from July 2000 to June 2002	25,445
JOHN MILFORD Calgary, Alberta	Executive Vice President, Exploration	2007	Vice President, Exploration and Corporate Development of Fortress Prior thereto, Vice President, Exploration of Marauder Resources East Coast Inc. from 2005 to 2006 Prior thereto, Founder and President of Mojo Energy from 2003 to 2005 Prior thereto, Founder and President, of Primal Energy Corporation from 1999 to 2003	119,633
ROBERT D'ADAMO	Vice President, Land	2007	Vice President, Land Prior thereto, Senior Land Negotiator for EnCana Corporation since 2006 Prior thereto, Vice President, Business Development, Land and Marketing at NAV Energy Trust. Prior thereto, 1997 to 2003, Manager, Land Negotiations at Petro-Canada Oil and Gas	25,316

Notes:
(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.

As at December 31, 2007, the directors, officers and senior management of the Corporation, as a group, beneficially owned, directly or indirectly, 604,141 Common Shares of the Corporation or approximately 3.8% of the issued and outstanding Common Shares.

The term of the office of each director will expire at the next annual general meeting of the shareholders.

Conflicts of Interest

Circumstances may arise where members of the board of directors of the Corporation are directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such board members will be provided to the Corporation. Pursuant to the ABCA, directors who have an interest in a proposed transaction upon which the board of directors is voting are required to disclose their interests and refrain from voting on the transaction.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation:

(a) as at the date of this AIF or has been, within the 10 years before the date of the AIF, a director or executive officer of any company, that while that person was acting in that capacity,

  (i) was 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;

  (ii) 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

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

(b) has, within the 10 years before the date of the AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become 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, officer or shareholder.

AUDIT COMMITTEE INFORMATION

The full text of the audit committee mandate is included in Schedule “C” of this AIF.

Composition of the Audit Committee as at March 31, 2008

George Watson

Mr. Watson holds a Bachelor of Science (Engineering) degree and MBA from Queen’s University, as well as an AMP from Harvard University. Mr. Watson served as Chief Financial Officer of TransCanada Pipelines Ltd. for several years. Mr. Watson is independent and financially literate.

Will Franklin

Mr. Franklin is a Director of Lime Rock Partners, a firm specializing in providing growth capital for the energy sector. He has over 13 years experience in corporate finance, private equity, and energy and is a graduate of the University of Texas at Austin (B.A., B.B.A.) and the Harvard Business School (M.B.A). Mr. Franklin is independent and financially literate.

Rick Grafton

Mr. Grafton is President & CEO of Grafton Capital Corporation, a private capital company concentrating on long term value creation. Prior thereto, Mr. Grafton acted as Executive Vice President & Managing Director, Global Head of Energy of Canaccord Adams. He was responsible for all aspects of the firm's oil and gas operations. Mr. Grafton was a former Managing Director and a Founding Shareholder of FirstEnergy Capital Corp. ("FirstEnergy"). Mr. Grafton graduated from the University of British Columbia with a Bachelor of Commerce majoring in Finance in 1977. Mr. Grafton is independent and financially literate.

Pre-Approval Policies and Procedures

Under the mandate of the audit committee, the audit committee must pre-approve the retention of the auditor for any significant non-audit services permitted under applicable securities laws and the fee for such service.

External Auditor Service Fees

The following table provides information about the fees billed to the Corporation for professional services rendered by Ernst & Young LLP Chartered Accountants during fiscal years 2007 and 2006:

	2007 ($)	2006 ($)
Audit Fees (1)	120,000	150,000
Audit-Related Fees (2)	117,000	50,000
Tax Fees (3)	102,645	2,900
All Other Fees (4)	1,100	1,504
Total	340,745	204,404

Notes:

(1) Audit fees consist of fees for the audit of the Corporation's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as Audit Fees. During fiscal years 2007 and 2006, the services provided in this category included due diligence reviews in connection with acquisitions and dispositions, research of accounting and audit-related issues and procedures related to the reorganization of Signal and the issuance of flow-through common shares.

(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal year 2007, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns.

(4) During fiscal year 2007, the services provided in this category included Annual CPAB levy (Public Accountability Board).

PROMOTERS

There are no persons or companies, within the three most recently completed financial years or during the current financial year, acting as promoters of the Corporation.

LEGAL PROCEEDINGS

There are no legal proceedings in progress for any claims for damages that exceed 10% of the current assets of the Corporation. There have been no penalties or sanctions imposed against the Corporation by a court or regulatory body (whether relating to securities legislation or otherwise) or settlement agreements entered into with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

On November 15, 2006, Signal acquired all of the issued and outstanding shares of Marauder. Shareholders of Marauder were paid an aggregate of $15,000,000 cash and 16,349,534 common shares of Signal. As a result of the transaction, LRP Luxembourg Holdings Sarl ("Lime Rock") holds in the aggregate 14.68% of the issued and outstanding common shares of Signal. Pursuant to the acquisition of Marauder, Lime Rock was entitled to two (2) nominees to the Board of Signal. After the Reorganization, Lime Rock holds greater than 10%of the issued and outstanding Fortress common shares.

Except as described above there have been no material transactions with directors, executive officers or with a beneficial owner who owns more than ten percent of the Common Shares, or with any of their associates or affiliates within the last three most recently completed financial years or during the current financial year.

AUDITOR, TRANSFER AGENT AND REGISTRAR

The Corporation's Auditor is Ernst & Young LLP, Chartered Accountants located at 1000, 440 - 2nd Avenue S.W., Calgary, Alberta. Ernst & Young LLP, Chartered Accountants have been the auditors of the Corporation since 1996.

The Corporation's Transfer Agent and Registrar is Olympia Trust Company, its offices in Calgary and Toronto.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, there have been no material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year that are still in effect other than the Arrangement Agreement effecting the Reorganization as described under the heading "CORPORATE STRUCTURE - Name, Address and Incorporation".

INTERESTS OF EXPERTS

Sproule Associates Limited has prepared a report pursuant to National Instrument 51-101 dated March 6, 2008, relating to the Corporation's oil and gas reserves.

The Corporation has been advised that Sproule Associates Limited and their officers, directors and employees hold less than 1% of the securities issued by the Corporation.

ADDITIONAL INFORMATION

Additional information including director's and officer's renumeration and indebtnesses, principal holders of the Corporation's securities and securities issued, and authorized for issuance under the Corporation's equity compensation plan will be contained in the Corporation's 2008 proxy materials relating to its annual shareholders meeting to be held on May 26, 2008.

Additional financial information is provided in the Corporation's financial statements and MD&A for its most recently completed financial year.

Additional information relating to the Corporation can be found in the public documents of the Corporation which can be accessed on the SEDAR website at www.sedar.com.

SCHEDULE "A"
FORM 51-101F2

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Fortress Energy Inc. (the "Company"):

1. We have evaluated the Company'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 Company's management. Our responsibility is to express an opinion on the Reserves Data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2007, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of Fortress Energy Inc., As of December 31, 2007, prepared January to March 2008	Canada				
Total			Nil	78,070	Nil	78,070

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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:

Sproule Associates Limited
Calgary, Alberta
March 06, 2008

Colleen M. Rogers, C.E.T.
Shareholder

L Precul

Lucia M. Precul, P.Eng.
Associate

M. Maughan.

Michael W. Maughan, C.P.G., P.Geol.
Vice-President, Geoscience

Harry J. Helwerda, P.Eng.
Executive Vice-President

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

Management of Fortress Energy Inc. (the "Corporation") is 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 consists of the following:

(a) (i) proved plus probable oil and gas reserves estimated as at December 31, 2007 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves as at December 31, 2007 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporations' reserves data. The report of the independent reserves evaluator will be filed with the securities regulatory authorities concurrent with this report.

The Board of Directors of the Corporation has:

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

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

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

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 approved:

(a) the content and filing with the securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator and the reserves data; and

(c) the content and filing of this report.

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

Dated this 31st day of March, 2008.

"signed"
J. Cameron Bailey
President and Chief Executive Officer

"signed"
Darren Jackson
Chief Operating Officer

"signed"
George Watson
Director

"signed"
Donald Leitch
Director

SCHEDULE "C"

AUDIT COMMITTEE MANDATE

The Audit Committee (the "Committee") of the Board of Directors (the "Board") of Fortress Energy Inc. ("Corporation") shall have the oversight responsibility, authority and specific duties as described below.

I. Composition, Independence and Compensation

The Committee shall be comprised of three or more directors as determined by the Board. The members shall be independent as determined by applicable regulatory requirements.

All members of the Committee shall have a working familiarity with basic finance and accounting practices, and shall have the ability to read and understand the financial statements of the Corporation and the accounting issues raised therein and at least one member of the Committee shall have accounting or related financial management expertise.

Members of the Committee shall be appointed by the Board and shall serve until their successors are duly appointed. The Chair of the Committee may be designated by the members of the Committee.

II. Responsibility

The Committee's primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to (i) the integrity of the annual and quarterly financial statements to be provided to shareholders and regulatory bodies; (ii) the Corporation's compliance with accounting and finance based legal and regulatory requirements; (iii) the independent auditor's qualifications and independence; (iv) the system of internal accounting and financial reporting controls that management has established; and, (v) performance of the external audit process and the independent auditor. The Committee shall also prepare such reports as are required to be prepared by it by applicable securities law. In addition, the Committee provides an avenue for communication between each of the internal audit, the independent auditors, financial and senior management and the Board. The Committee shall have a clear understanding with the independent auditors that they must maintain an open and transparent relationship with the Committee, and that the ultimate accountability of the independent auditors is to the Committee, as representatives of the shareholders. The Committee shall make regular reports to the Board concerning its activities. The Committee, in its capacity as a committee of the Board, subject to shareholder approval requirements, is directly responsible for the appointment, compensation, retention and oversight of the work of the independent auditors.

The Committee shall make regular reports to the Board concerning its activities.

III. Meetings

The Committee shall meet at least four times annually and as many additional times as the Committee deems necessary to carry out its duties effectively. The Committee shall meet in separate sessions with management, the senior internal audit executive of the Corporation and the independent auditors at each regularly scheduled meeting.

IV. Specific Duties

To carry out its oversight responsibilities, the Committee shall:

A. AUDIT SPECIFIC DUTIES

(i) Auditor Qualifications and Selection

1. Subject to applicable law requiring shareholder approval of auditors, be solely responsible for selecting, retaining, compensating, overseeing and, where necessary, terminating the independent auditors, who shall be registered with the Canadian Public Accountability Board. The independent auditor shall be required to report directly to the Committee. The Committee shall be entitled to adequate funding from the Corporation for the purpose of compensating the independent auditor for completing an audit and audit report.

2. Evaluate the independent auditor's qualifications, performance and independence. As part of that evaluation, at least annually obtain and review a report by the independent auditor describing: the firm's (auditor's) internal quality-control procedures; any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps taken to deal with any such issues; and (to assess the auditor's independence) all relationships between the independent auditor and the Corporation; and ensure that the independent auditors do not provide non-audit services that would disqualify them as independent under applicable regulations.

3. Review the experience and qualifications of the senior members of the independent auditor team and the quality control procedures of the independent auditor; ensure that the lead audit partner of the independent auditor is replaced periodically, in accordance with regulatory requirements applicable to the Corporation; recommend to the Board guidelines for the Corporation's hiring of senior employees and former employees of the independent auditor who were engaged on the Corporation's account.

(ii) Audit Process

1. Pre-approve all auditing services; subject to applicable securities laws, pre-approve the retention of the independent auditor for any significant non-audit services permitted under applicable securities law and the fee for such services. All pre-approvals of such non-audit services shall be disclosed as required by applicable securities law. The Committee may delegate to one or more of its members the authority to grant pre-approvals required hereunder provided that any pre-approvals so granted are presented in writing to the Committee at the next regularly scheduled meeting.

2. Meet with the independent auditor prior to the audit to review the scope and general extent of the independent auditor's annual audit including the planning and staffing of the audit. This review should include an explanation from the independent auditors of the factors considered by the auditors in determining their audit scope, including the major risk factors.

3. Require the independent auditor to provide a timely report setting forth (i) all critical accounting policies, significant accounting judgments and practices to be used; (ii) all alternative treatments of financial information within Generally Accepted Accounting Principles ("GAAP") that have been discussed with management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the

independent auditor; and, (iii) other material written communications between the independent auditor and management.

4. Upon completion of the annual audit, review the following with management and the independent auditors:

- The annual financial statements including related footnotes and the MD&A to be included in the Corporation's annual report to shareholders or included in the Corporation's Annual Information Form.
- The significant accounting judgements and reporting principles, practices and procedures applied by the Corporation in preparing its financial statements including any newly adopted accounting policies and the reasons for their adoption.
- The results of the audit of the financial statements and the related audit report thereon. The independent auditors should confirm to the Committee that no limitations were placed on the scope or nature of their audit procedures.
- Significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit, including any problems or disagreements with management which, if not satisfactorily resolved, would have caused the independent auditors to issue a non-standard report on the Corporation's financial statements.
- The co-operation received by the independent auditors during their audit, including access to all requested records, data and information.
- Any other matters not described above that are required to be communicated by the independent auditors to the Committee pursuant to Auditing Standards.

5. Generally, as part of the review of the annual financial statements, receive an oral report(s), at least annually, concerning legal and regulatory matters that may have a material impact on the financial statements. Discuss major financial risk exposures and steps management has taken to monitor and control such exposures.

B. ONGOING DUTIES

1. Review and reassess the adequacy of this Mandate periodically and recommend any proposed changes to the Board for approval.

2. Report regularly to the Board and review with the Board any issues that arise with respect to the quality or integrity of the Corporation's financial statements, the Corporation's compliance with legal or regulatory requirements, the performance and independence of the Corporation's independent auditor, or the performance of the internal audit function.

3. Discuss the types of information that it is appropriate for the Corporation to disclose in earnings press releases or other earnings guidance. Review with management and the Corporation's independent auditors all quarterly financial statements and MD&A prior to the filing of such reports with the applicable securities regulators and prior to any public announcement of financial results for the periods covered, including the results of the independent auditor's reviews of the quarterly financial statements, significant adjustments, new accounting policies, and any disagreements between the independent

auditors and management. The Chair of the Committee may represent the entire Committee for purposes of this review.

4. The Committee shall have the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties.

5. 5. Perform any other activities consistent with this Mandate, the Corporation's By-Laws and applicable law, as the Committee or the Board deems necessary or appropriate.

C. INTERNAL CONTROL SUPERVISION DUTIES

1. Review with the Corporation's management and the independent auditors the Corporation's internal accounting and financial reporting controls, any significant deficiencies in them and any proposed major changes to them.

2. Review with management, the Chief Financial Officer and the independent auditors the methods used to establish and monitor the Corporation's policies with respect to unethical or illegal activities by Corporation employees that may have a material impact on the financial statements.

3. Meet with management and the independent auditors to discuss any relevant significant recommendations that the independent auditors may have, particularly those characterized as "material" or "serious".

4. Review the appointment of the senior accounting executive.

5. Review with management any correspondence with regulators or governmental agencies and any employee complaints or published reports which raise material issues regarding the Corporation's financial statements or accounting policies.

6. Review with management and the independent auditor any off-balance sheet financing mechanisms, transactions or obligations of the Corporation.

7. Review with management and the independent auditor any related party transactions.

8. Establish, implement and, as necessary, revise the procedures for (i) the receipt, retention, and treatment of complaints received by the Corporation regarding accounting, financial reporting controls, or auditing matters; and, (ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

9. 9. Review with the independent auditors the quality of the Corporation's accounting personnel; review with management the responsiveness of the independent auditors to the Corporation's needs.

D. REGULATORY COMPLIANCE DUTIES

1. Prepare the necessary disclosure regarding the Committee and its duties and action as is required under applicable regulatory policy.

2. Prepare such reports as are required to be prepared by the Committee pursuant to applicable securities law.