

FINANCIAL AND OPERATING SUMMARY

	2007		2006	
	(\$000's)	\$/boe	(\$000's)	\$/boe
Petroleum and natural gas sales	13,895	38.43	9,090	44.92
Realized gain on commodity contracts	393	1.09	-	-
	14,288	39.52	9,090	44.92
Royalties	(2,688)	(7.43)	(1,398)	(6.93)
Operating costs	(4,030)	(11.15)	(2,161)	(10.71)
Operating netback ⁽¹⁾	7,570	20.94	5,531	27.28
General and administrative expenses	(3,786)	(10.47)	(4,350)	(21.57)
Net interest income (expense)	(856)	(2.37)	1,433	7.25
Funds from operations ⁽¹⁾	2,928	8.10	2,614	12.96
Unrealized gain on commodity contracts	92	0.25	-	-
Depletion, depreciation and accretion	(11,192)	(30.95)	(4,955)	(24.57)
Stock-based compensation	(2,513)	(6.95)	(822)	(4.08)
Loss before other items:	(10,685)	(29.55)	(3,163)	(15.69)
Gain on sale of oil and gas property, plant and equipment	-	-	15,835	78.51
Goodwill impairment	-	-	(4,548)	(22.55)
Income (loss) before income taxes	(10,685)	(29.55)	8,124	40.27
Future income tax recovery (expense)	2,715	7.51	(36)	(0.18)
Net income (loss)	(7,970)	(22.04)	8,088	40.09

(1) Non-GAAP measures. See discussion in the following MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 31, 2008

Management's discussion and analysis ("MD&A") should be read in conjunction with the consolidated financial statements of Fortress Energy Inc. ("Fortress" or the "Company", formerly known as SignalEnergy Inc.) for the years ended December 31, 2007 and 2006. The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). All tabular amounts in the following discussion are in thousands of Canadian dollars unless otherwise noted. Additional information is available on the Company's web site at www.fortressenergy.ca or under the Company's profile at www.sedar.com.

Non-GAAP Measurements

The terms "funds from operations" and "operating netback" used in the MD&A are not recognized measures under GAAP. Management believes that in addition to net income, funds from operations and operating netback are useful supplemental measures as they provide an indication of the results generated by the Company's principal business activities before the consideration of how those activities are financed. Investors are cautioned, however, that these measures should not be construed as alternatives to net income determined in accordance with GAAP, as an indication of the Company's performance.

Reconciliation of "Funds from Operations" to Cash Flow from Operating Activities per GAAP

The Company's method of calculating funds from operations may differ from that of other companies, and, accordingly it may not be comparable to measures used by other companies. The Company calculates funds from operations by taking cash flow from operating activities as determined under GAAP before changes in non-cash operating working capital and abandonment expenditures. The consolidated statements of cash flows included in the consolidated financial statements present the reconciliation between net income (loss) and funds from operations. A summary of this reconciliation is as follows:

(\$000's)	2007	2006
Cash flow from operating activities	3,570	741
Change in non-cash operating working capital	(722)	1,873
Abandonment expenditures	80	-
Funds from operations	2,928	2,614

BOE Presentation

Natural gas reserves and volumes recorded in thousand cubic feet are converted to barrels of oil equivalent ("boe") on the basis of six thousand cubic feet ("mcf") of gas to one barrel ("bbl") of oil. The term "barrels of oil equivalent" may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead.

Forward Looking Statements

Statements in this MD&A may contain forward looking information including expectations of future production, components of cash flow and earnings, expected future events and/or financial results that are forward looking in nature and subject to substantial risks and uncertainties. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. The Company cautions the readers that actual performance will be affected by a number of factors, as many may respond to changes in economic and political circumstances throughout the world. Events or circumstances may cause actual results to differ materially from those predicted, a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to: the risks associated with the oil and gas industry, commodity prices and exchange rate changes; industry related risks could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans; risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. These external factors beyond the Company's control may affect the marketability of oil and natural gas produced, industry conditions including changes in laws and regulations, changes in income tax regulations, increased competition, fluctuations in commodity prices, interest rates, and variations in the

Canadian/United States dollar exchange rate. The reader is cautioned not to place undue reliance on this forward looking information.

Statements throughout this MD&A that are not historical facts may be considered “forward looking statements.” These forward looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company’s objectives, goals or future plans are forward looking statements. Since forward looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to any number of risks including, but not limited to:

- a. Risks associated with the oil and gas industry and regulatory bodies (e.g. operational risks in exploration, development and production, or changes in royalty rates);
- b. Delays or changes in plans with respect to exploration or development projects or capital expenditures;
- c. Uncertainty of estimates and projections relating to recoverable reserves, costs and expenses;
- d. Health, safety and environmental risks; and
- e. Commodity price and exchange rate fluctuations.

DESCRIPTION OF THE BUSINESS

Fortress Energy Inc. was formed through the reorganization (the “Reorganization”) of SignalEnergy Inc. (“Signal”), including an arrangement (the “Arrangement”) under the Companies Act (Quebec), which was approved at a Special Meeting of Shareholders on February 15, 2007 and was effective February 20, 2007. Further details are provided in notes 2 and 10 to the audited consolidated financial statements.

Fortress’ primary focus is the exploration and development of natural gas reserves in Western Canada. The Company has approximately 87,011 net acres of undeveloped land in the Ladyfern, Velma and Buick Creek areas in NE British Columbia and the Chigwell, Bashaw, Square Creek, Halverson, Mearon and Dahl areas of Alberta.

The Company’s strategy is to ‘acquire and exploit’ properties that are early in their development cycle that offer exploration, appraisal and development drilling opportunities, while maintaining low finding and development costs. Fortress operates most of its production enabling it to have complete control over cost management of its capital programs.

CORPORATE HIGHLIGHTS

During the year ended December 31, 2007, Fortress accomplished the following:

- Drilled 11 gross development wells, 3 gross exploration wells and completed 7 recompletion operations at Ladyfern South, Mearon North and Square Creek. This program added 200 boe/d of new production and two new pool discoveries.
- Increased proven reserves to 4,108 mboe and proven plus probable reserves to 6,456 mboe.
- Increased average production to 1,256 boe/d for the fourth quarter of 2007 from 522 boe/d for the fourth quarter of 2006.
- Completed the reorganization of SignalEnergy Inc. on February 15, 2007.
- Announced the addition of Mr. Robert D’Adamo, VP Land, and Mr. Darren Jackson, COO, to the management team.
- Completed a strategic asset acquisition in the Ladyfern, Mearon and Velma areas in July for \$12.5 million, adding proven reserves of 1,040 mboe and proven plus probable reserves of 1,546 mboe. The acquisition included 54,232 net acres of undeveloped land, consolidating the Company’s land position in its core Ladyfern, Mearon and Velma areas.
- Secured a new \$25 million bank borrowing facility.

- Announced an agreement with AltaGas to construct a 41 km pipeline for the Square Creek development area to the AltaGas processing facility at Clear Prairie. Construction commenced in December and the final commissioning of the pipeline will be completed in early April 2008. .
- Raised \$5 million (\$4.4 million net) through a public offering of common shares on a flow-through basis in December.

DETAILED FINANCIAL ANALYSIS

Production

	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Sales volume:				
Natural gas (mcf/d)	7,455	3,012	5,845	2,744
Oil and NGL's (bbl/d)	13	20	16	95
Total(boe/d)	1,256	522	990	553
Sales price:				
Natural gas (\$/mcf)	6.19	7.19	6.32	6.95
Oil and NGLs (\$/bbl)	86.95	56.47	68.15	59.94
Total (\$/boe)	38.07	44.13	38.43	44.92
Benchmark prices:				
AECO average price (\$/mcf)	6.00	6.89	6.60	6.54
Edmonton par (\$/boe)	80.75	65.24	75.49	73.72

Sales volumes for the year ended December 31, 2007 increased to 990 boe/d compared to 553 boe/d for 2006 as result of the Company's acquisition of Marauder Resources West Coast Inc. ("Marauder") on November 15, 2006 which added sales gas volumes of 450 boe/d. The Company's 2007 drilling program, which included 14 gross (8 net) wells in the Ladyfern South, Mearon North and Square Creek areas, and 7 recompletion operations, added additional volumes of 200 boe/d in the second quarter of 2007. In July 2007, the Company acquired a partner's working interest in Ladyfern North, Mearon North and Velma increasing the Company's working interest to 100% in these areas. This strategic acquisition added additional volumes in the third quarter of 225 boe/d which the Company had increased in the fourth quarter to 425 boe/d with the start up of two wells at Velma in late August. In the first quarter of 2006, the Company sold its oil and natural gas assets in the Redwater, Carrot Creek, Ferrier and Kaybob areas which recorded sales volumes of 674 boe/d in that quarter. The Company retained its Buick Creek, Chigwell and Bashaw properties which were producing at a rate of approximately 330 boe/d at the time of the sale.

Sales volumes in the fourth quarter of 2007 increased to 1,256 boe/d from 522 boe/d in the fourth quarter of 2006. Late in the third quarter of 2007, the Company added a refrigeration plant to its Ladyfern property improving its natural gas liquids recovery and lowering the dew point of the gas entering a third party processing facility, improving the time on production for these wells. In late August 2007, the Company brought two wells at Velma on stream and after optimizing in September these wells were producing at a combined rate of 426 boe/d. The Velma wells are tied into the Ladyfern gathering system and the start-up of these wells increased the line pressures and reduced production volumes from the Company's Ladyfern wells by approximately 120 boe/d. As part of the first quarter 2008 capital program, the Company is adding compression at Ladyfern to restore lost production. The Company's acquisition of Marauder in November 2006 added incremental sales volumes for the fourth quarter of 2006 of 230 boe/d.

Natural gas accounted for substantially all of the Company's sales in 2007. The change in sales mix from 2006 is a result of the sale of the Company's oil producing assets in the first quarter of 2006 and the Marauder acquisition in the fourth quarter of 2006. The average price realized in 2007 for natural gas (net of transportation costs and before realized gains on commodity contracts) was \$6.32/mcf compared to the AECO average price of \$6.60/mcf. For the fourth quarter of 2007, the Company realized a natural gas price of \$6.19/mcf (net of transportation costs and before realized gains on commodity contracts) compared to the average AECO price of \$6.00/mcf.

Revenue

	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Petroleum and natural gas sales (\$000's)	4,396	2,149	13,895	9,090
\$/boe	38.07	44.13	38.43	44.92

Petroleum and natural gas sales for the year ended December 31, 2007 were \$13,895,000 compared to \$9,090,000 for the year prior. This increase is due to an increase in sales volumes from 553 boe/d in 2006 to 990 boe/d in 2007 which is attributable to the acquisition of Marauder, the 2007 drilling program and the asset acquisition in July. This increase was affected by a reduction in natural gas prices realized by the Company in 2007 of 14.4% from 2006 prices.

For the three months ended December 31, 2007, the Company recorded sales of \$4,396,000 compared to \$2,149,000 for the same period in 2006. This increase is attributed to the items previously noted.

A reconciliation of petroleum and natural gas sales between 2007 and 2006 is as follows:

	(\$000's)
Petroleum and natural gas sales – year ended December 31, 2006	9,090
Effect of increased production year-over-year	7,144
Effect of decreased product prices year-over-year	(2,339)
Petroleum and natural gas sales – year ended December 31, 2007	13,895

Realized and Unrealized Gains on Commodity Contracts

The Company uses commodity contracts to manage its exposure to fluctuations in the price of natural gas. In 2007, the Company 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. In the fourth quarter of 2007, the Company recorded realized gains on commodity contracts of \$35,000, or \$0.30/boe, and unrealized gains of \$19,000, or \$0.16/boe.

The following commodity contracts were in place at December 31, 2007 and March 31, 2008:

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

Royalties

	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Royalties (net of Alberta Royalty Tax Credit) (\$000's)	1,317	24	2,688	1,398
\$/boe	11.41	0.49	7.43	6.93
Percentage of petroleum and natural gas sales	30.0	1.1	19.3	15.4

Royalties were \$2,688,000 for the year ended December 31, 2007 compared to \$1,398,000 for the prior year. The increase reflects increased sales volumes in 2007. As a percentage of petroleum and natural gas sales (net of transportation costs and before realized gains on commodity contracts), royalties increased to 19.3% in 2007 compared to 15.4% from the prior year. This increase is attributed to increased production volumes in the fourth quarter from the start-up of the Company's Velma property which records a royalty rate of approximately 20%. Contributing to this increase was a \$294,000 charge resulting from a reassessment by Alberta Taxation of Alberta Royalty Tax Credits ("ARTC") claimed for prior taxation years and a charge for royalties of \$235,000 related to prior periods, which were based on best estimates at that time. These additional charges are approximately 3.8% of petroleum and natural gas sales for 2007. The Company's wells at Ladyfern North qualify for the Ultra-Marginal Royalty Program which assesses a reduced royalty

rate for low producing wells in the province of British Columbia, resulting in an effective royalty rate of approximately 8% for these wells.

For the fourth quarter of 2007, royalties increased to \$1,317,000 from \$24,000 for the fourth quarter of 2006. This increase is attributed to increased sales in the fourth quarter of 2007. As a percentage of petroleum and natural gas sales royalties were 30.0% in the fourth quarter of 2007 compared to 1.1% for the fourth quarter of 2006. The increase in the fourth quarter of 2007 compared to the royalty rate realized for all of 2007 is due to increased production from the Velma property and additional charges, previously noted. The fourth quarter of 2006 reflects a reduction in royalties of \$426,000 to reflect unrecognized Alberta Royalty Tax Credits ("ARTC").

On October 25, 2007, the Alberta Government released "The New Royalty Framework" which summarizes the Government's decision on Alberta's new royalty structure pertaining to oil and gas resources, including oil sands, conventional oil and gas, and coal bed methane. This is in response to recommendations recently put forth by the Alberta Royalty Review Panel. This new royalty structure will take effect on January 1, 2009. Based on our review of the new royalty structure, our current production will be affected only in a modest way at current prices. In some cases, royalty rates will actually decline from current rates depending upon rates of production in 2009 and future years. On this basis, and assuming current prices, we believe that a majority of our inventory will continue to provide economic returns. The actual effect on the Company will be determined based on the actual legislation enacted, production rates, commodity prices, foreign exchange rates, production mix and service costs as they exist on January 1, 2009. For 2007, approximately 34% of the Company's production was from Alberta with the remaining 66% from British Columbia. In addition, approximately 36% of the proven plus probable reserves at December 31, 2007 are in Alberta, with the remaining 64% from British Columbia.

Operating Expenses

	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Operating (\$000's)	1,762	279	4,030	2,161
\$/boe	15.26	5.73	11.15	10.71

Operating expenses increased in 2007 to \$4,030,000 from \$2,161,000 in 2006 due to an increase in sales volumes, as previously noted. In 2007, operating expenses were \$11.15/boe compared to \$10.71/boe in 2006. Operating expenses for 2007 include natural gas processing, road usage and maintenance, and contract operating expenses related to 2006 totaling \$341,000, or \$0.94/boe. Excluding these 2006 costs, operating expenses for 2007 amounted to \$10.21/boe.

For the fourth quarter of 2007, operating expenses were \$1,762,000, or \$15.26/boe, compared to \$279,000 for the fourth quarter of 2006, or \$5.73/boe. Operating expenses increased in the fourth quarter of 2007 due to increased production volumes from the start-up of the Velma wells late in the third quarter and an under estimation in prior quarters attributed to a lack of experience with the Marauder assets. In addition, the Company recorded incremental consulting services of \$77,000 (or \$0.67/boe) and methanol costs of \$72,000 (\$0.62/boe). Additional operating expenses are typically recorded in the fourth quarter due to the "winter access" nature of the Company's properties as certain operations can only be conducted during these winter months.

General and Administrative Expenses

	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Gross (\$000's)	1,608	1,405	5,399	4,760
Partner recoveries (\$000's)	(115)	-	(304)	-
Capitalized (\$000's)	(362)	(240)	(1,309)	(410)
Net (\$000's)	1,203	1,165	3,786	4,350
\$/boe	10.42	24.19	10.47	21.57

General and administrative expenses decreased to \$3,786,000 in 2007 from \$4,350,000 in 2006. In the first quarter of 2006, the Company sold a substantial portion of its oil and gas assets and became the target of a

takeover transaction. As a result of the asset sale, the Company substantially curtailed its operations in the first quarter of 2006. In 2006, the Company underwent a downsizing incurring severance and retention costs of approximately \$959,000 and incremental legal costs of \$360,000. After the closing of the Marauder transaction, the Company rehired technical staff to execute on its capital program for first quarter of 2007. Gross general and administrative expenses increased in 2007 to \$5,399,000 from \$4,760,000 in 2006. This increase reflects an allowance for doubtful accounts receivable balances of \$525,000. General and administrative expenses for the three months ended December 31, 2007 were \$1,203,000 compared to \$1,165,000 for the three months ended December 31, 2006.

As a result of the rehiring of staff and significant ramp up in exploration and development activities, general and administrative expenses capitalized in 2007 increased to \$1,309,000 from \$410,000 in 2006. The Company's policy is to capitalize salaries, consulting fees and software costs that are directly attributable to exploration and development activities.

Stock-based Compensation Expense

	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Stock-based compensation expense (\$000's)	2,084	-	2,513	822
\$/boe	18.05	-	6.95	4.08

Stock-based compensation expense for the year ended December 31, 2007 increased to \$2,513,000 from \$822,000 for 2006. On October 4, 2007, the Company cancelled 1,193,000 stock options that were outstanding resulting in a charge to the consolidated statement of operations of \$2,063,000 of previously unrecognized compensation cost related to these options. As a result of the sale of oil and gas assets and a takeover bid in the first quarter of 2006, the Company vested all outstanding stock options on March 1, 2006. As a result, the recognition of stock-based compensation expense in 2006 was accelerated.

Interest Income and Expense

Interest income of \$219,000 for the year ended December 31, 2007 represents interest earned on the invested cash from the sale of oil and gas assets in the first quarter of 2006 to the time of the Reorganization and \$30 million redemption of common shares in February 2007. At December 31, 2006, the Company held \$35,048,000 of commercial paper investments with a yield of 4.3%. Interest income for 2006 also relates to invested cash from the sale of oil and gas properties in the first quarter.

Interest expense increased to \$1,075,000 in 2007 from \$498,000 in the prior year due to increased borrowings to finance operations and the asset acquisition that was completed in July. With the sale of oil and gas assets in the first quarter of 2006, the Company repaid its revolving credit facility that was outstanding at that time. Interest expense for 2007 also reflects interest and penalties of \$105,000 related to the audits of ARTC and a 2003 flow-through share issuance of a subsidiary company.

Interest expense in the fourth quarter of 2007 was \$434,000 representing interest on the Company's bank line and interest and penalties resulting from the ARTC audit, compared to \$133,000 in the fourth quarter of 2006 which relates entirely to interest on unspent flow-through obligations.

Depletion, Depreciation and Accretion Expense

	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Depletion and depreciation expense (\$000's)	4,536	1,418	11,039	4,865
Accretion of asset retirement obligations (\$000's)	71	15	153	90
Total (\$000's)	4,607	1,433	11,192	4,955
Depletion and depreciation expense (\$/boe)	39.90	29.52	30.53	24.12
Accretion of asset retirement obligations (\$/boe)	0.61	0.31	0.42	0.45
Total (\$/boe)	40.51	29.83	30.95	24.57

Depletion and depreciation expense was \$11,039,000 for the year ended December 31, 2007 compared to \$4,865,000 for the prior year. This increase is attributed to a 79% increase in sales volumes over 2006 levels, and an additional depletion and depreciation charge of \$1,404,000 resulting from a ceiling test impairment at December 31, 2007. Depletion and depreciation expense for 2007 increased to \$30.53/boe from \$24.12/boe in 2006. The impact of the ceiling test impairment charge is \$3.88/boe for the year ended December 31, 2007 and results from minor downward technical revisions to reserves and a decrease in forecast natural gas prices for 2008 and 2009. The impact of the ceiling test impairment on the fourth quarter depletion and depreciation expense is \$12.16/boe.

Estimated future development costs for proved undeveloped properties included in the calculation of depletion expense at December 31, 2007 increased to \$16,435,000 from \$15,595,000 at the end of 2006. Undeveloped land costs at December 31, 2007 increased to \$7,371,000 from \$3,158,000 at December 31, 2006 and were excluded from assets subject to depletion.

Accretion expense for the year ended December 31, 2007 was \$153,000 compared to \$90,000 for the prior year. This increase is due to additional wells added in the first quarter of 2007 and an increase in working interests resulting from the asset acquisition in July of 2007. Accretion expense for the fourth quarter of 2007 of \$71,000 increased from the fourth quarter of 2006 due to additional wells added, as previously noted. In addition, the Company recorded additional accretion expense of \$30,000 in the fourth quarter of 2007 as a result of a loss on settlement of retirement obligations.

Income Tax

The Company 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 on current commodity prices and planned capital expenditures, the Company 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. As of March 31, 2008, the Company has incurred approximately \$1,000,000 of eligible expenditures.

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

	(\$000's)
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

Net Income (Loss)

(\$000's except per share and per boe amounts)	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Net income (loss)	(5,442)	(5,609)	(7,970)	8,088
Net income (loss) per share - basic and diluted	(0.40)	(0.08)	(0.59)	0.11
Net income (loss) per boe	(47.13)	(116.80)	(22.04)	40.09

The Company recorded a net loss of \$7,970,000 for the year ended December 31, 2007 compared to net income of \$8,088,000 for the prior year. This translates into a basic and diluted net loss per share of \$0.59 for 2007 and basic and diluted net income per share for 2006 of \$0.11. The 2007 net loss is attributable to a reduction in the operating netback realized, a significant increase in depletion and depreciation expenses as a result of a ceiling test impairment, and an increase in stock-based compensation expense. Net income for 2006 was the result of a gain on sale of oil and gas assets recorded of \$15,835,000.

For the fourth quarter of 2007, the Company recorded a net loss of \$5,442,000 compared to \$5,609,000 for the fourth quarter of 2006. In the fourth quarter of 2006 the Company recorded a reduction of \$4,120,000 to the previously recorded gain on sale of oil and gas assets resulting from additional capital expenditures required to complete commitments to the purchaser of those assets. In the fourth quarter of 2007, the Company recorded additional depletion and depreciation expenses of \$1,404,000 as a result of a ceiling test impairment, as previously noted.

Funds from Operations

(\$000's except share and per boe amounts)	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Funds from (used in) operations	(282)	1,089	2,928	2,614
Funds from operations (\$/boe)	(2.44)	22.68	8.10	12.96
Funds from operations per share – basic and diluted	(0.02)	0.02	0.22	0.04

Funds from operations for the year ended December 31, 2007 were \$2,928,000 compared to \$2,614,000 for 2006. This increase is attributed to an increase in production in 2007 of 79% over the prior year, reduced by a lower operating netback realized which decreased from \$27.28 for 2006 to \$20.94 as a result of lower natural gas prices realized and an increase in operating costs. The Company also recorded additional general and administrative expenses related to doubtful accounts receivable balances in the fourth quarter of 2007.

Funds used in operations for the fourth quarter of 2007 were \$282,000 – a decrease of \$1,371,000 from the fourth quarter of 2006. This decrease is due to a substantially lower operating netback in the fourth quarter of 2007, reflecting reduced natural gas prices and increases in royalties and operating expenses, and additional general and administrative expenses, as noted.

Capital Expenditures

(\$000's)	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Land and seismic	38	(33)	232	94
Drilling and completions	1,495	(704)	11,696	1,343
Equipment and facilities	1,766	(367)	10,873	2,293
Property acquisitions	20	255	12,963	720
Corporate acquisition	-	23,208	-	23,208
Capitalized overhead costs	362	240	1,309	410
Other	211	56	1,377	126
	3,892	22,655	38,450	28,194

Total capital expenditures for 2007 were \$38,450,000 compared to \$28,194,000 in 2006. The Company's initial capital program was \$15,000,000 which was allocated to the first quarter drilling program focusing exclusively on the Company's lands in the Ladyfern, Mearon, Square Creek, and Drake areas. The Company 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 wells. In addition, the Company completed 7 recompletion operations of 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 Company was not actively engaged in exploration or development opportunities due to the sale of oil and gas assets in the first quarter.

The capital program was expanded in the third quarter of 2007 to include the acquisition of a partner's working interests in the Ladyfern, Mearon and Velma areas for cash of \$12,535,000. The acquisition included approximately 280 boe/d of natural gas production with additional production behind pipe, estimated reserves of 1,040 mboe on a proven basis and 1,546 mboe on a proven plus probable basis, and 54,232 net acres of undeveloped land. The Company 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 line in late August and is expected to provide greater reliability of processing capabilities and generate additional processing revenues for the Company. The Company also completed the surface facilities and the tie-in of two wells at Velma which came on production in late August.

The Company's approved capital expenditures for 2008 is \$8,100,000 which is expected to be incurred primarily in the first quarter and is focused on the Company's Square Creek development area in Alberta.

Share Capital

	Three months ended December 31,		Year ended December 31,	
	2007	2006	2007	2006
Weighted average common shares outstanding – basic and diluted	13,417,746	74,494,047	13,417,746	74,494,047

Options to purchase 397,000 common shares at December 31, 2007 (December 31, 2006 – 110,000) were not included in the calculation of weighted average – diluted common shares outstanding because they were anti-dilutive.

Outstanding securities	
Common shares	15,970,059
Stock options	397,000
Total outstanding securities at December 31, 2007	16,367,059
Common shares issued in the first quarter of 2008	16,829
Total outstanding securities at March 31, 2008	16,383,888

The estimated fair value of stock options of \$0.50 per share (December 31, 2006 - \$0.71) is amortized to expense over the three-year vesting period on a straight-line basis. In 2007, the Company recorded compensation expense of \$2,513,000 (2006 – \$822,000).

On December 21, 2007, the Company closed a public offering of 2,703,000 flow-through common shares at \$1.85 per share for total gross proceeds of \$5,000,550 (\$4,395,000 net of share issuance costs). The full expenditure commitment was renounced to subscribers effective December 31, 2007 with all expenditures to be incurred by December 31, 2008. As of March 31, 2008, the Company has incurred eligible expenditures of approximately \$1,000,000.

Liquidity and Capital Resources

The Company has a working capital deficiency of \$24,029,000 at December 31, 2007. The Company has a \$25 million revolving, demand credit facility with its bank (the "Bank"), bearing interest at the Bank's prime lending rate plus 0.25% (effective interest rate for 2007 of 6.5%) and collateralized by an interest over all present and after acquired property of the Company. The authorized limit is subject to annual review and re-determination of the Company's borrowing base by the Bank.

The credit facility has a covenant that requires the Company to maintain its working capital ratio at 1:1 or greater while the credit facility is outstanding. The working capital ratio is defined as current assets plus the unutilized portion of the credit facility divided by current liabilities less the balance drawn against the credit facility. The Company is in compliance with this covenant at December 31, 2007 but will not be at March 31, 2008. Due to the winter access nature of the Company's properties much of its capital program is conducted in the first quarter of the year causing a working capital deficiency. The Company has kept the Bank apprised of its working capital covenant.

(\$000's)	As at December 31, 2007
Revolving operating loan available	25,000
Working capital deficiency	(24,029)
Capital resources available	971

The Company's initial capital budget for 2008 is \$8,100,000. The 2008 capital program will be funded through a combination of cash flow from operations and the available credit facility. The Company is contemplating an additional equity financing in the second quarter of 2008 and has taken initial steps in this regard.

Cash provided by operating activities was \$3,570,000 for 2007 compared to \$741,000 for 2006. This increase is due to an increase in funds from operations in 2007 of \$234,000 resulting from an increase in sales volumes, and an increase in non-cash working capital balances of \$2,595,000. For the fourth quarter of 2007, funds used in operations were \$282,000 compared to funds from operations of \$1,089,000 - due to a decrease in the operating netback realized and additional general and administrative expenses attributed to bad debts expense incurred in the fourth quarter of 2007.

Cash used in financing activities for 2007 was \$3,638,000 compared to \$19,776,000. In the first quarter of 2007, the Company redeemed 23,076,923 common shares as part of the Reorganization of Signal for \$30,400,000. The Company was advanced additional funds on its bank credit facilities to fund a \$12,535,000 asset acquisition in July, 2007. In December of 2007, the Company completed a flow-through share offering for gross proceeds of \$5,001,000 (net \$4,395,000). In the first quarter of 2006 the Company used the proceeds from the sale of oil and gas assets to repay the Company's operating line of credit which had \$28,600,000 drawn at that time. In addition, the Company received proceeds of \$3,199,000 for the exercise of employee stock options in 2006.

Cash used in investing activities for 2007 was \$36,644,000 compared to cash provided by investing activities of \$55,730,000 for 2006. Cash used in investing activities for 2007 reflects capital expenditures for the Company's drilling program, new facilities and the strategic asset acquisition in July. In 2006, cash provided by investing activities reflects net cash proceeds of \$91,223,000 on the sale of oil and gas assets in the first quarter of 2006 and relatively minor capital expenditures of \$4,986,000 due to the downsizing of its operations in 2006.

Related Party Transactions

In 2007, the Company was charged \$522,000 in legal fees by a law firm where a director of the Company is a partner, of which \$212,000 is included in accounts payable and accrued liabilities at December 31, 2007.

All related party transactions are in the normal course of business and have been measured at the agreed to exchange amounts, which are the amounts of consideration established and agreed to by the related parties and which are similar to those negotiated with third parties.

Subsequent Events

Subsequent to December 31, 2007, the Company issued a letter of credit for \$1,000,000 with an expiry of February 1, 2009 related to a gas transportation and processing agreement (refer to note 13 to the consolidated financial statements).

On January 1, 2008, the Company amalgamated with its subsidiary companies.

Commitments and Contingencies

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 payables under these agreements. These agreements relate to a predecessor company which was a cancer drug discovery enterprise.

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:

	(\$000's)
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 41 km 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:

	(\$000's)
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, represents only the Company's 50% working interest. Included in accounts receivable at December 31, 2007 is \$745,000 due from AltaGas that relates to preliminary construction costs incurred by the Company.

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.

SELECTED QUARTERLY INFORMATION

	2007				2006			
	Q4	Q3 (1)	Q2 (1)	Q1	Q4	Q3	Q2	Q1
Production:								
Natural gas (mcf/d)	7,455	6,111	5,082	4,699	3,010	1,777	1,833	4,366
Oil and NGL's (bbl/d)	13	7	29	22	20	35	69	263
Barrels of oil equivalent (boe/d)	1,256	1,025	876	805	522	331	375	991
Average realized price:								
Natural gas (\$/mcf)	6.19	5.07	6.86	7.47	7.19	5.31	6.04	7.86
Oil and NGLs (\$/bbl)	86.95	71.42	52.14	60.56	57.19	65.43	57.08	59.62
Barrels of oil equivalent (\$/boe)	38.07	30.68	41.52	45.48	44.13	35.46	40.08	50.45
Benchmark prices:								
AECO average price (\$/mcf)	6.00	5.12	7.11	7.37	6.89	5.68	6.02	7.58
Edmonton Par (\$/bbl)	80.75	80.70	72.65	67.86	65.24	80.26	80.43	68.90
Financial (\$'000's unless otherwise noted):								
Petroleum and natural gas sales	4,396	2,893	3,310	3,296	2,149	1,079	1,362	4,500
Net income (loss)	(5,442)	(1,603)	(617)	(308)	(5,635)	(13)	270	13,440
Net income (loss) per share – basic (\$)	(0.39)	(0.12)	(0.05)	(0.02)	(0.07)	(0.00)	0.00	0.19
Net income (loss) per share – diluted (\$)	(0.39)	(0.12)	(0.05)	(0.02)	(0.07)	(0.00)	0.00	0.19
Funds from (used in) operations	(282)	505	1,147	1,558	1,089	821	17	687
Operating costs (\$/boe)	15.26	10.31	8.23	8.82	5.73	8.51	13.13	13.07
Weighted average shares outstanding – basic ('000)	13,561	13,266	13,258	13,262	81,439	73,266	72,595	70,598
Weighted average shares outstanding – diluted ('000)	13,561	13,266	13,258	13,262	81,439	73,266	73,316	71,239

(1) Restated to eliminate the effect of realized gains on commodity contracts.

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding required disclosure. The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that the Company's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information related to the Company, including its consolidated subsidiaries, is made known to them by others within those entities. It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Internal Controls over Financial Reporting

The Company has conducted a review of the design of its internal controls over financial reporting, with the conclusion that as at December 31, 2007, the Company's system of internal controls over financial reporting is sufficiently designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the Company's GAAP. In its assessment, the Company identified certain material weaknesses in the design of its internal controls over financial reporting:

- a) due to the small number of staff, it is not feasible to achieve the complete segregation of incompatible duties; and
- b) due to the small number of staff, the Company relies upon third parties as participants in the Company's internal controls over financial reporting and accounting for income taxes.

The Company believes these weaknesses are mitigated by: the active involvement of senior management and the board of directors in all the affairs of the Company; open lines of communication within the Company; the present levels of activities and transactions within the Company being readily transparent; the thorough review of the Company's financial statements by management, the board of directors and by the Company's auditors. In addition, the Company has increased the size of its finance team in 2007. However, these mitigating factors will not necessarily prevent the likelihood that a material misstatement will not occur as a result of the aforesaid weaknesses in the Company's internal controls over financial reporting. A system of internal controls over financial reporting, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the internal controls over financial reporting are met.

Changes in Accounting Policies and Practices

Effective January 1, 2007, the Company adopted six new accounting standards issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook Section 3855 "Financial Instruments – Recognition and Measurement", Section 3861 "Financial Instruments – Disclosure and Presentation", Section 3865 "Hedges", Section 1506 "Accounting Changes", Section 1530 "Comprehensive Income" and Section 3251 "Equity".

The adoption of these standards did not impact January 1, 2007 opening balances.

- (i) Financial instruments – recognition and measurement

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities, and non-financial derivatives. It requires that financial assets and financial liabilities, including derivatives, be recognized on the balance sheet when the Company becomes a party to the contractual provisions of the financial instrument or non-financial derivative contract. Under this standard, all financial instruments are required to be measured at fair value upon initial recognition except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, available-for sale, held-to-maturity, loans or receivables, or other financial liabilities. Financial assets and financial liabilities held for-trading are measured at fair value with changes in those fair values recognized in net earnings. Financial assets held-to-maturity, loans and receivables, and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Investments in equity instruments classified as available-for-sale that do not have a quoted market price in an active market are measured at cost.

Cash and cash equivalents and risk management assets are designated as "held-for-trading". Accounts receivable are designated as "loans or receivables". The revolving operating loan and accounts payable and accrued liabilities are designated as "other liabilities".

Derivative instruments are recorded on the balance sheet at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host

contracts. Changes in the fair values of derivative instruments are recognized in net earnings, with the exception of derivatives designated as effective cash flow hedges and hedges of the foreign currency exposure of a net investment in a self-sustaining foreign operation, which are recognized in other comprehensive income. In addition, Section 3855 requires that an entity must select an accounting policy of either expensing debt issue costs as incurred or applying them against the carrying value of the related asset or liability. The Company's policy is to expense debt issue costs as incurred.

(ii) Hedges

Section 3865 provides alternative treatments to Section 3855 for entities which choose to designate qualifying transactions as hedges for accounting purposes. It replaces and expands on Accounting Guideline 13 "Hedging Relationships", and the hedging guidance in Section 1650 "Foreign Currency Translation" by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. The Company has elected not to apply hedge accounting to its financial instruments.

(iii) Accounting changes

Section 1506 provides expanded disclosures for changes in accounting policies, accounting estimates and corrections of errors. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. As well, voluntary changes in an accounting policy are to be made only when required by a primary source of GAAP or the change results in more relevant and reliable information.

(iv) Comprehensive income (loss) and accumulated other comprehensive income (loss)

Section 1530 introduces comprehensive income, which consists of net earnings and other comprehensive income ("OCI"). OCI represents changes in shareholder's equity during a period arising from transactions and changes in prices, markets, interest rates, and exchange rates. OCI includes unrealized gains and losses on financial assets classified as available-for-sale, unrealized translation gains and losses arising from self-sustaining foreign operations net of hedging activities and changes in the fair value of the effective portion of cash flow hedging instruments.

New Canadian Accounting Pronouncements

- (i) On December 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, *Capital Disclosures*, Handbook Section 3862, *Financial Instruments – Disclosures*, and Handbook Section 3863, *Financial Instruments – Presentation*. These new standards are effective January 1, 2008. Section 1535 specifies the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance. The new Sections 3862 and 3863 replace Handbook Section 3861, *Financial Instruments – Disclosure and Presentation*, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks. We are currently assessing the impact of these new standards on our financial statements.
- (ii) The Canadian Accounting Standards Board (AcSB) has confirmed that the use of International Financial Reporting Standards ("IFRS") will be required in 2011 for publicly accountable profit-oriented enterprises. IFRS will replace Canada's current GAAP for those enterprises. These include listed companies and other profit-oriented enterprises that are responsible to large or diverse groups of stakeholders. The official changeover date is for interim and annual financial statements relating to fiscal years beginning on or after Jan. 1, 2011. Companies will be required to provide comparative IFRS information for the previous fiscal year. Fortress is currently evaluating the impact of adopting IFRS.

BUSINESS RISKS and UNCERTAINTIES

Fortress' production and exploration activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to the much larger integrated petroleum companies. Fortress is subject to the various types of business risks and uncertainties including:

- finding and developing oil and natural gas reserves at economic costs;
- production of oil and natural gas in commercial quantities; and
- marketability of oil and natural gas produced.

In order to reduce exploration risk, the Company strives to employ highly qualified and motivated professional employees with a demonstrated ability to generate quality proprietary geological and geophysical prospects. To help maximize drilling success, Fortress combines exploration in areas that afford multi-zone prospect potential, targeting a range of low to moderate risk prospects with some exposure to select high-risk with high-reward opportunities. The Company explores in areas where the Company has drilling experience.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most appropriate technology and information systems. In addition, the Company seeks to maintain operational control of its prospects.

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, Fortress conducts its operations at high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Company maintains current insurance coverage for general and comprehensive liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect changing corporate requirements, as well as industry standards and government regulations. Fortress may periodically use financial or physical delivery hedges to reduce its exposure against the potential adverse impact of commodity price volatility, as governed by formal policies approved by senior management subject to controls established by the Board of Directors.

CRITICAL ACCOUNTING ESTIMATES

The reader is advised that the critical accounting estimates, policies, and practices as described in this MD&A and report continue to be critical in determining Fortress' financial results.

The reader is further cautioned that the preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes. Changes in these judgments and estimates could have a material impact on the financial results and financial condition. The following discussion outlines accounting policies and practices that are critical to determining the Company's financial results:

Accounting for Petroleum and Natural Gas Operations

The Company follows the full cost method of accounting whereby all costs relating to the acquisition of, exploration for and development of oil and gas reserves are capitalized in a single Canadian cost center. Such costs include lease acquisition, lease rentals on undeveloped properties, geological and geophysical costs, drilling both productive and non-productive wells, production equipment and overhead charges directly related to acquisition, exploration and development activities.

The application of the full cost method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper income tax treatment of the costs incurred.

Full cost accounting depends on the estimated proven reserves that are believed to be recoverable from the Company's oil and gas properties. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Our reserve estimates are based on current production forecasts, prices and economic conditions. Fortress' reserves were evaluated by the independent engineering firm Sproule Associates Ltd.

Reserve estimates are critical to many of our accounting estimates, including:

- Calculating our unit-of-production depletion and future site restoration rates. Proven reserve estimates are used to determine rates that are applied to each unit-of-production in calculating depletion expense.
- Assessing when necessary, oil and gas assets for possible impairment. Estimated future undiscounted cash flows are determined using proven reserves. The criteria used to assess impairment, including the impact of changes in reserve estimates, are discussed below.

As circumstances change and additional data becomes available, reserve estimates also change, possibly materially impacting net income. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although we make every reasonable effort to ensure that our reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to our reserve estimates can arise from changes in oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

It would take a very significant decrease in our proven reserves to limit our ability to borrow money under our credit facility.

Impairment of Petroleum and Natural Gas Properties

The Company reviews its full cost pool for impairment annually. An impairment provision is recorded whenever events or circumstances indicate that the carrying value of the Company's properties may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and probable petroleum and natural gas reserves, as estimated by the Company on the balance sheet date. Reserve estimates, as well as estimates for petroleum and natural gas prices and production costs may change, and there can be no assurance that impairment provisions will not be required in the future.

Management's assessment of, among other things, the results of exploration activities, commodity price outlooks, and planned future development and sales, impacts the amount and timing of impairment provisions.

Asset Retirement Obligations

The asset retirement obligations provision recorded in the consolidated financial statements is based on an estimate for total costs for future site restoration and abandonment of the Company's petroleum and natural gas properties. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures, and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors, including changing technology, political and regulatory environments.

Income Taxes

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its consolidated financial statements and its tax returns. These

amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. The Company periodically assesses its ability to realize on its future tax assets. If Fortress concluded that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset will be reduced by a valuation allowance.

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.

With the above risks and uncertainties, the reader is cautioned that future events and results may vary significantly from that which Fortress currently foresees.