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rockenergy INC.

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Annual Information Form

Year Ended December 31, 2008

March 12, 2009

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ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	Barrel
Bbls	Barrels
Mbbls	thousand barrels
Mmbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
Mmbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule

Other

AECO	The natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° 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 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
mt	Megatonnes
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
Mcfe	million cubic feet equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
Mstboe	1,000 stock tank barrels of oil equivalent
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

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", "budget", "plan", "continue", "estimate", "expect", "forecast", "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, 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 applicable law.

In particular, this Annual Information Form and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- the quantity of reserves;
- oil and natural gas production levels;
- capital expenditure programs;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under government regulatory and taxation regimes.

The Corporation's 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 Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves;
- risks and uncertainties inherent in exploration and development activities;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value, or failure to realize the anticipated benefits, of acquisitions; and
- geological, technical, drilling and processing problems.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The Corporation does not undertake any obligation to publicly update or revise any forward-looking statements except as required by securities laws or regulations.

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**GLJ**" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the report of GLJ dated March 5, 2009 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2008;

"**Gross**" or "**gross**" means:

(a) in relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest;

"**Net**" or "**net**" means:

(d) in relation to the Corporation's interest in production and reserves, the Corporation's interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation's royalty interest in production or reserves;

(e) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(f) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation; and

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

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

ROCK ENERGY INC.

General

Rock Energy Inc. (the "**Corporation**" or "**Rock**"), formerly Medbroadcast Corporation ("**Medbroadcast**"), changed its name to Rock Energy Inc. effective February 18, 2004 in conjunction with a continuation of Medbroadcast from the federal jurisdiction of Canada to the jurisdiction of the province of Alberta.

Medbroadcast was incorporated pursuant to the *Company Act* (British Columbia) on February 15, 1988 under the name "Prime Equities Inc.". On October 25, 1991, Medbroadcast's Memorandum was amended to change the name of Medbroadcast to "Prime Equities International Corporation", to consolidate its common shares on a 1:10 basis, and to increase the authorized capital back up to 700,000,000 shares divided into 400,000,000 common shares without par value and 300,000,000 preference shares ("**Preference Shares**") without par value. On August 11, 1998, the Corporation's Memorandum was amended to change the name of the Corporation to "medEra Life Science Corporation". On January 4, 2000, the Corporation continued into the federal jurisdiction of Canada pursuant to the *Canada Business Corporations Act*. Concurrent with such continuation, the Corporation changed its name to "Medbroadcast Corporation" and revised its authorized capital to consist of an unlimited number of common shares and 300,000 preference shares. In conjunction with such continuation, Medbroadcast adopted By-laws in place of the Articles.

On February 18, 2004 Medbroadcast was continued out of the federal jurisdiction of Canada into the Province of Alberta, the name of the Corporation was changed to "Rock Energy Inc." and the common shares of the Corporation were consolidated on a 1:30 basis.

The Corporation is a public energy company engaged in the exploration for and development and production of crude oil and natural gas, primarily in Western Canada.

The Corporation's head office is located at Suite 800, 607 – 8th Avenue S.W., Calgary, Alberta, T2P 0A7 and its registered office is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

Subsidiaries and Partnerships

Rock has one active wholly-owned subsidiary, Rock Energy Ltd. ("**Rock Energy**"). Rock Energy was incorporated on November 21, 2002 under the *Business Corporations* Act (Alberta) as 1018369 Alberta Ltd. and changed its name to Rock Energy Ltd. on December 10, 2002.

All of the Rock Energy oil and gas properties are beneficially owned by the Rock Energy Production Partnership (the "**Partnership**"). The partners of the Partnership are the Corporation and Rock Energy. Legal title to the oil and gas properties is held by Rock Energy.

Unless the context otherwise requires, reference in this Annual Information Form to the "Corporation" includes the Corporation, Rock Energy and the Partnership.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

In the third quarter of 2006 the Corporation in separate transactions divested four property areas (Wild River, Highland/Hudson, Cherill and Chestermere) as part of its stated goal of rationalizing its property base. Approximately 820 boe per day of production (approximately 100% natural gas) and 1.4 million boe of proven plus probable reserves (as evaluated by GLJ effective December 31, 2008) were sold in the transactions. The proceeds of $30.8 million were used to repay bank indebtedness.

On September 28, 2007, the Corporation completed a private placement to ARC Energy Fund 5 ("**ARC 5**") (the "**Private Placement**") and issued 2,998,623 common shares of the Corporation at a price of $4.05 per share for gross proceeds of approximately $12.1 million.

On September 28, 2007, immediately following the Private Placement, the Corporation acquired all of the outstanding shares of Greenbank Energy Ltd. ("**Greenbank**") (the "**Greenbank Acquisition**") pursuant to a plan of arrangement (the "**Plan of Arrangement**") under the *Business Corporations Act* (Alberta). Pursuant to the Plan of Arrangement, Rock paid to Greenbank Shareholders aggregate consideration of $24.0 million consisting of the issuance of an aggregate 3,143,167 common shares and cash consideration in an amount equal to the gross proceeds of approximately $12.1 million which was received from ARC 5 pursuant to the Private Placement. The properties acquired through the Plan of Arrangement are located in Alberta producing approximately 500 boe per day at the time of the acquisition and are predominately natural gas focused. The acquisition also included approximately 26,000 net (75,000 gross) acres of undeveloped land. The largest and most significant producing property is located in Elmworth, Alberta (31% average working interest) which at the time of the acquisition consisted of a large contiguous land block totalling over 73,600 gross acres and 20 producing wells. Other properties include:

- Kakwa, Alberta (36% average working interest);
- Teepee, Alberta (100% working interest); and
- Edson/Windfall, Alberta (62% average working interest).

In connection with these transactions, on September 28, 2007 Matt Brister resigned as a director of the Corporation and Malcolm Adams, the Vice President of ARC Financial Corp., joined the Board of Directors of the Corporation.

Significant Acquisitions

There were no significant acquisitions by the Corporation or any significant probable acquisition by the Corporation within or since the completion of the most recently completed financial year of the Corporation.

Recent Developments

The deterioration in commodity prices over the last 4 months of 2008 and continuing into 2009 have caused the Corporation to evaluate its short term capital spending plans. See "Description of the Business and Principal Properties – 2009 Capital Spending on page 7 of this Annual Information Form.

DESCRIPTION OF THE BUSINESS AND PRINCIPAL PROPERTIES

The Corporation is engaged in the exploration for and development and production of crude oil and natural gas primarily in Western Canada.

Corporate Strategy

Rock's corporate strategy is to grow and develop an oil and gas exploration and production company through internal operations and acquisitions. Rock's current geographic focus is east central Alberta and west central Saskatchewan (which comprises the Corporation's Plains core area) and the deep basin of western Alberta (which comprises the Corporation's West Central core area). As Rock grows, the Corporation intends to expand operations in each of its core areas as well as develop additional core areas.

Rock intends to evaluate acquisitions, both properties and corporate, in its target core areas to compliment future internal operations and potentially add new core areas. Rock will continue to evaluate other acquisition opportunities over time, as the company continues to grow and execute its business plan.

2008 Capital Spending

The Corporation spent $50.2 million on net capital expenditures for the year ended December 31, 2008 drilling 33 (24.3 net) wells. Facilities and natural gas gathering expenditures were $14.1 million for the year as compression and pipeline facilities were constructed and brought on stream at Saxon in the first half of 2008 and due to the completion of tie-in operations in the Musreau and Kakwa areas in the first quarter of 2008.

Plains core area drilling consisted of 18 (18.0 net) heavy oil wells and 1 (1.0 net) dry hole in 2008. All of the heavy oil wells were placed on production in 2008 which increased production from 1,140 Bbls/day in January 2008 to 1,440 Bbls/day in December 2008.

West Central core area drilling consisted of 14 (5.3 net) gas wells in 2008 at the following properties:

- Elmworth: 7 (2.1 net)
- Saxon: 1 (1.0 net)
- Tony Creek: 2 (0.9 net)
- Girouxville: 2(0.9 net)
- Musreau/Kakwa: 1 (0.2) net
- Markerville: 1 (0.2 net)

Rock operated 5 (2.5 net) of these wells. All of the wells were brought on stream in 2008 except for 2 (0.6 net) Elmworth wells which were delayed until the first quarter of 2009 behind compression. West Central core area production has increased from 1,070 BOE/day in January 2008 to 2,300 BOE/day in December 2008 with the majority of the production increase coming from Saxon and Elmworth.

Land and seismic expenditures were $7.3 million in 2008 as the Corporation added undeveloped acreage and acquired seismic at Elmworth and Saxon in the West Central core area and in the Plains core area. Net undeveloped acreage totalled 80,574 net acres at the end of 2008, a 31% increase over the previous year. Minor non-core property dispositions were completed in 2008 for $1.2 million.

2009 Capital Spending

In early 2009, commodity prices are 75-80 percent lower than at mid-2008. In this period, Rock will respond proactively to changing commodity prices, and use the cash generated from operations to drill a limited number of wells to preserve our reserve base, improve operating efficiencies, pay down debt and fund strategically-located asset acquisitions. Management believes a careful approach to spending is prudent in these uncertain times and will work to strengthen and position Rock to take advantage of opportunities the market may provide. Rock's Board of Directors has approved a preliminary capital budget of $17.5 million for 2009 based on a average price forecast for WTI oil of US$47.00 per barrel and AECO natural gas of Cdn$5.00 per mcf and a $US/Canadian dollar exchange rate of 0.80. This basic budget includes drilling 2 (1.3 net) wells in the first quarter at Saxon and Elmworth, followed by 8 (8.0 net) heavy oils wells and 2 (1.35 net) gas wells in the second half of 2009 and $1.8 million to acquire seismic and land in order to expand the drilling inventory. The Corporation intends to limit capital spending in 2009 to be less than cash flow in the current commodity price environment.

Principal Properties

The following is a description of the Corporation's oil and natural gas properties as at December 31, 2008. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2008.

Medicine River, Alberta

Rock owns 1,440 (962 net) acres in the Medicine River area of central Alberta. The property includes 6 (5.4 net) producing oil wells and 3 (2.0 net) producing gas wells and 1 (0.8 net) shut-in gas well with an average working interest in production of 94%. No disposal or injection wells are located on the property. Production is initially processed through Rock's 100% owned facility which is located on these lands. The facility processes the oil in order to meet pipeline specifications and it is then trucked to a third party terminal for sale. The facility also meters and compresses Rock's operated natural gas production which is tied-in to a third party processing plant for ultimate sale. Rock operates all the production (except 1 (0.3 net) gas wells) and its facility through a contract operator. The natural gas production comes from the Edmonton, Pekisko, Nordegg and Glauconite sands and the oil production comes from the Jurassic, Pekisko and Basal Quartz formations. Rock does not own rights to all the zones on these lands so other companies also have wells on these lands.

Plains Core Area (east central Alberta and west central Saskatchewan)

Rock owns 23,643 (23,518 net) acres of land in the Plains core area of east central Alberta and west central Saskatchewan, which consists of four main property areas with the majority of production coming from the Lloydminster property in east central Alberta. The core area includes 44 (44.0 net) producing heavy oil wells, 1 (0.94 net) producing gas well, 2 (2.0 net) standing gas wells, 26 (26.0 net) shut-in oil wells and no disposal wells. Rock's average working interest in production is over 99%. The heavy oil wells have been drilled every year beginning in 2004 with most of the production coming on since late 2005. These wells are primarily producing from the Sparky formation. Production is processed at 100% owned well site batteries and then trucked to a third party terminal for sale. Gas production is tied into a 93.75% owned gathering lines which ties in to third party pipelines and processing facilities where the gas is sold. Management expects additional drilling in 2009.

West Central Core Area (deep basin Alberta)

Bigstone, Alberta

The Bigstone area which is within the Greater Kaybob region includes Rock's Saxon, Tony Creek and Waskahigan properties. The Corporation's interests in the Bigstone area includes 13 (4.2 net) producing natural gas wells, 7 (2.6 net) standing or shut-in natural gas wells, 1 (0.1 net) producing oil well, and no shut-in oil or disposal wells. The natural gas wells drilled at Saxon and Tony Creek in late 2007 and early 2008 came on production in 2008 as gathering infrastructure was put in place. The Saxon facility was installed in Q1 and Q2 of 2008 with first production in May 2008. Production is processed at a third party facility. Rock owns 15,840 (8,611 net) acres in the area and has extensive 2D and 3D seismic coverage. An additional well (0.8 net) was drilled at Saxon in the first quarter of 2009.

Elmworth, Alberta

Rock owns 89,598 (44,635 net) acres of land in the Elmworth area of Alberta, with 2D and 3D seismic coverage. The property includes 35 (10.1 net) producing natural gas wells, 15 (4.6 net) shut-in natural gas wells, and 1 (0.3 net) producing oil well. No company owned disposal or injection wells are located in this area. Rock's average working interest in production for the area is 30%. Production is predominately sweet natural gas which is processed through company and third party facilities. The area has established gathering and processing infrastructure. Rock has a 31.25% interest in a sweet natural gas compressor station that ties into the Conoco Elmworth Gas Plant and a 10% interest in a compressor capable of processing sour natural gas tied in to the Wembley and Sexsmith Gas Plants. An expansion of the compressor station tied into the Conoco Elmworth Gas Plant completed in 2008 doubled the capacity of the facility. The natural gas production primarily comes from the Bluesky, Gething and Nikanassin formations. Rock does not own rights to all the zones on these lands so other companies also have wells on these lands. An additional well (0.3 net) was drilled in the first quarter of 2009.

Cutbank, Alberta

The Corporation's interest in the Cutbank area include Rock's Kakwa, North Kakwa, Musreau and Chicken properties. The Corporation's interests in the area includes 15 (3.6 net) producing natural gas wells, 8 (3.1 net) producing oil wells, 2 (0.5 net) shut-in gas wells, 3 (0.8 net) shut-in oil wells, and no disposal wells with an average working interest in production of 22%. The gas wells production primarily comes from the Cadomin, Gething, Bluesky, Fahler and Chinook formations. The oil wells production is generally Cardium production. The wells are non-operated, except for 2 (1.8 net) gas wells which were both tied-in to third party facilities in 2008. Gas is gathered and processed at third party plants in the area. The Corporation owns 20,320 (6,342 net) acres of land in the area.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 5, 2009. The effective date of the Statement is December 31, 2008 and the preparation date of the Statement is March 4, 2009.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ with an effective date of December 31, 2008 contained in the GLJ Report. The Reserves Data summarizes the oil, liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Company engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. All of Rock's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Corporation's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein. For more information as to risks involved, see "*Risk Factors - Reserve Estimates*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2008
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net G (Mbbl)	ross (Mbbl)	Net G (Mbbl)	ross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	263	225	1,963	1,666	12,779	10,159	335	223
Developed Non-producing	20	18	156	135	1,170	958	12	7
Undeveloped	0	0	485	385	1,345	1,085	44	33
TOTAL PROVED	283	242	2,603	2,185	15,295	12,202	392	264
PROBABLE	103	86	2,070	1,660	11,878	9,453	175	116
TOTAL PROVED PLUS PROBABLE	386	328	4,673	3,845	27,173	21,654	567	380

	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/YEAR
RESERVES CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	($/BOE)/ ($/Mcfe)
PROVED											
Developed Producing	135,106	114,195	99,586	88,764	80,395	129,769	110,505	96,923	86,779	78,876	26.16/4.36
Developed Non-Producing	10,106	7,522	5,965	4,909	4,141	7,702	5,692	4,523	3,744	3,183	18.69/3.11
Undeveloped	13,657	10,361	8,031	6,326	5,043	10,175	7,504	5,643	4,299	3,300	13.42/2.24
TOTAL PROVED	158,870	132,077	113,582	100,000	89,579	147,646	123,701	107,089	94,822	85,358	24.04/4.01
PROBABLE	116,782	83,892	63,884	50,497	40,955	87,107	61,954	46,686	36,501	29,269	18.58/3.10
TOTAL PROVED PLUS PROBABLE	275,652	215,969	177,466	150,496	130,534	234,753	185,655	153,775	131,323	114,627	21.74/3.62

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT AND RECLAMATION COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Reserves	318,548	48,896	94,554	11,704	4,524	158,870	11,223	147,646
Proved Plus Probable Reserves	572,315	95,990	159,438	35,316	5,919	275,652	40,899	234,753

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	UNIT VALUE ($/BOE)/($Mcfe)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	8,288	27.29/4.55
	Heavy Oil (including solution gas and other by-products)	44,465	20.10/3.35
	Natural Gas (including by-products but excluding solution gas from oil wells)	60,829	27.55/4.59
	Total	113,582	24.04/4.01
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	10,491	24.89/4.15
	Heavy Oil (including solution gas and other by-products)	78,211	20.10/3.35
	Natural Gas (including by-products but excluding solution gas from oil wells)	88,764	23.06/3.84
	Total	177,466	21.74/3.62

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **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.

(b) **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.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

  (i) **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 certainly.

  (ii) **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.

(d) **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) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. **Forecast Prices and Costs**

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at December 31, 2008, inflation and exchange rates utilized by GLJ in the GLJ Report, which were GLJ's then current forecasts at the date of the GLJ Report, were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2008
FORECAST PRICES AND COSTS

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS					
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Cromer Medium Crude 29° API ($Cdn/Bbl)	Hardisty Heavy Crude 12° API ($Cdn/Bbl)	AECO Gas Price ($Cdn/Mmbtu)	Edmonton Pentanes Plus ($Cdn/Bbl)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	Spec Ethane ($Cdn/Bbl)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast											
2009	57.50	68.61	59.00	43.10	7.58	69.98	43.22	52.14	25.55	2	0.825
2010	68.00	78.94	68.68	49.76	7.94	80.52	49.73	61.57	26.80	2	0.850
2011	74.00	83.54	73.52	54.35	8.34	85.21	52.63	65.16	28.19	2	0.875
2012	85.00	90.92	80.01	59.23	8.70	92.74	57.28	70.92	29.43	2	0.925
2013	92.01	95.91	84.40	62.54	8.95	97.82	60.42	74.81	30.27	2	0.950
2014	93.85	97.84	86.10	63.82	9.14	99.80	61.64	76.32	30.94	2	0.950
2015	95.73	99.82	87.84	65.13	9.34	101.81	62.89	77.86	31.62	2	0.950
2016	97.64	101.83	89.61	66.46	9.54	103.87	64.15	79.43	32.31	2	0.950
2017	99.59	103.89	91.42	67.83	9.75	105.97	65.45	81.03	33.02	2	0.950
2018	101.59	105.99	93.27	69.22	9.95	108.10	66.77	82.67	33.74	2	0.950
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	2	0.950

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2008, were \$8.72/Mcf for natural gas, \$95.86/Bbl for light and medium crude oil, \$71.58/Bbl for heavy crude oil and \$74.15/Bbl for natural gas liquids.

4. The revenue forecasts included in the GLJ Report include the estimated costs to abandon the wells assigned reserves in the GLJ Report and to disconnect these wells from the gathering system. No costs have been included for the abandonment of surface facilities or gathering systems or for the reclamation of surface leases. **Also, no costs have been included in the GLJ Report for the abandonment of any of Rock's wells which have been assigned no reserves in the GLJ Report.**

5. The forecast price and cost assumptions assume the continuance of current laws and regulations.

6. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

Reconciliations of Changes in Reserves

The following table sets forth the reconciliation of our gross reserves as at December 31, 2008, using forecast price and cost estimates derived from the GLJ Report.

RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED & NON-ASSOCIATED GAS			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, 2007	383	189	572	2,275	1,489	3,764	14,717	12,960	27,677	207	153	360
Discoveries	-	-	-	1,000	741	1,741	406	269	675	2	1	3
Extensions and Improved Recovery	-	-	-	-	-	-	2,081	833	2,914	46	18	64
Technical Revisions	(29)	(87)	(115)	(185)	(161)	(346)	2,068	(2,076)	(8)	227	3	230
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	(309)	(109)	(418)	(2)	(1)	(2)
Economic Factors												
Production	(71)	-	(71)	(486)	-	(486)	(3,667)	-	(3,667)	(88)	-	(88)
December 31, 2008	284	102	386	2,603	2,070	4,673	15,295	11,878	27,173	392	175	567

Notes:

(1) Reserves in the table above are gross reserves, namely the Corporation's interest share before deduction of royalties and without including any royalty interests of the Corporation.

(2) Figures may not add due to rounding.

Additional Information Relating to Reserves Data

Proved and Probable Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation's assets for the years ended December 31, 2008, 2007 and 2006 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	-	305	305	1,320	1,320	-	-
2006	-	-	210	419	-	348	-	-
2007	-	-	151	232	2,047	2,047	17	17
2008			322	485	695	1,345	39	44

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	-	781	781	396	396	-	-
2006	-	-	507	871	1,685	2,009	15	15
2007	4	4	270	836	3,151	5,055	23	39
2008	-	4	630	1,308	1,402	5,223	23	55

The significant majority of the undeveloped reserves are expected to be developed within the next two years of the effective date.

In some cases, particularly if commodity price expectations are too low to justify capital expenditures at that time, it will take the Corporation longer than two years to develop these reserves.

Significant Factors or Uncertainties

A discussion of important economic factors and significant uncertainties that affect components of the reserves data can be found under the heading "Critical Accounting Estimates" in the Corporation's management discussion and analysis relating to the financial statements for the year ended December 31, 2008, which forms part of the Corporation's 2008 Annual Report, which discussion and analysis is incorporated herein by reference.

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 Reserves ($000)	Forecast Prices and Costs (Undiscounted) Proved Plus Probable Reserves ($000)
2009	2,487	11,157
2010	6,554	18,625
2011	2,419	4,666
2012	0	48
2013	0	97
Thereafter	244	723
Total	11,704	35,316

The Corporation expects to have sufficient internally generated cash flow and/or available credit facilities to finance the future development costs noted above.

Other Oil and Gas Information

Oil And Gas Wells

The following table sets forth the number and status of wells in which the Corporation has a working interest as at December 31, 2008.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	66	45.5	18	14.9	87	27.1	49	19.0
British Columbia	-	-	1	0.4	3	1.7	6	2.1
Saskatchewan	17	13.9	14	12.8	1	0.9	1	1.0
Total	83	59.4	33	28.1	91	29.7	56	22.2

Properties with no Attributable Reserves

The following table sets out the Corporation's undeveloped land holdings as at December 31, 2008.

	Undeveloped Acres	
	Gross	Net
Alberta	122,241	70,980
British Columbia	5,951	2,218
Saskatchewan	7,381	7,376
Total	135,573	80,574

Of the Corporation's undeveloped land, rights to explore, develop and exploit 19,503 (12,169 net) acres expire by December 31, 2009. The Corporation does not have any work commitments associated with its undeveloped lands.

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by the Corporation upon abandonment. The abandonment and reclamation costs are estimated based on field estimates and experience. The following table sets forth information respecting future abandonment and reclamation costs, for surface leases, wells, facilities and pipelines which the Corporation expects to incur for the periods indicated.

	Abandonment and Reclamation Costs escalated at 2.0% Undiscounted ($M)	Abandonment and Reclamation Costs escalated at 2.0% Discounted at 10% ($M)
Total anticipated to be paid	8,019,496	4,283,014
Anticipated to be paid in 2009	335,035	325,369
Anticipated to be paid in 2010	487,854	381,657
Anticipated to be paid in 2011	94,905	74,125

The Corporation estimates that it has 169.4 net wells which are subject to environmental reclamation obligations. Ongoing environmental obligations are expected to be funded out of cash flow from operating activities.

All but $3,495,500 ($1,943,000 discounted at 10%) and $2,100,500 ($1,844,000 discounted at 10%) of the above abandonment and reclamation costs have been included in the estimate of future net revenue from total proved and total proved plus probable reserves, respectively, in the GLJ Report. This difference is related to abandonment and reclamation of existing facilities and non-reserve wells and reclamation of reserve wells that are included in the GLJ report. None of these figures include possible future salvage value.

Tax Horizon

As at December 31, 2008, the Corporation has approximately $114.7 million of tax pools, of which $28.2 million are Canadian Exploration expense pools, $34.6 million are Canadian Development expense pools, $10.5 million are Canadian Oil and Gas Property expense pools and $29.5 million are capital property pools and $10.9 million are non-capital losses, therefore the Corporation does not expect to pay income taxes in 2009.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2008:

	2008 ($M)
Land acquisition costs	5,688
Seismic acquisition costs	1,614
Exploration drilling and completion costs	4,102
Development drilling and completion costs	18,689
Well equipment	5,213
Facilities and gas gathering systems	14,095
Property dispositions	(1,243)
Capitalized G&A	1,592
Well site facilities inventory	344
Office equipment	78
Total	50,172

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2008:

	Exploratory Wells		Development Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Light and Medium Oil	-	-	-	-	-	-
Heavy Oil	1	1.00	17	17.00	18	18.00
Natural Gas	2	1.56	12	3.73	14	5.28
Service	-	-	-	-	-	-
Dry	-	-	1	1.00	1	1.00
Total:	3	2.56	30	21.73	33	24.28

A discussion of exploration and development activities is set forth under "Description of the Business and Principal Properties".

Production Estimates

The following table sets out the volume of the Corporation's production estimated for the twelve months ended December 31, 2009 which is reflected in the estimate of future net revenue disclosed in the Forecast Prices and Costs table contained under " - Disclosure of Reserves Data".

	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	Gross (Bbls/d)	Gross (Bbls/d)	Gross (Mcf/d)	Gross (Bbls/d)	Gross (BOE/d)
Total Proved	135	1,946	9,311	209	3,841
Total Probable	7	133	1,485	20	408
Total Proved Plus Probable	142	2,079	10,796	229	4,249

Production History

The following tables summarize certain information in respect of production, product prices received and operating expenses made by the Corporation (and its subsidiaries) for the periods indicated below:

	Quarter Ended							
	2008				2007			
(6:1)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Daily Production[(1)]								
Light & Medium Crude Oil (Bbls/d)	169	171	220	216	206	195	215	243
Heavy Crude Oil (Bbls/d)	1,537	1,393	1,159	1,236	1,323	1,079	1,224	1,150
Gas (Mcf/d)	11,731	10,141	10,689	7,697	6,372	3,669	3,129	3,852
NGLs (Bbls/d)	298	272	293	94	81	79	75	79
Combined (BOE/d)	3,959	3,526	3,454	2,829	2,672	1,965	2,036	2,114
Average Price Received								
Light & Medium Crude Oil ($/Bbl)	57.20	115.38	116.82	89.43	81.66	75.29	65.10	62.39
Heavy Crude Oil ($/Bbl)	40.17	96.28	90.20	65.39	42.56	44.17	39.50	38.48
Gas ($/Mcf)	7.27	8.63	10.74	8.25	6.64	5.70	7.75	8.10
NGLs ($/Bbl)	45.78	88.61	92.18	66.48	67.81	61.47	57.58	52.65
Combined ($/BOE)	43.02	75.27	78.77	60.06	45.26	44.85	44.66	44.84
Royalties Paid								
Light & Medium Crude Oil ($/Bbls)	8.73	7.14	22.56	14.17	13.54	9.64	12.20	9.58
Heavy Crude Oil ($/Bbl)	8.84	21.51	19.48	13.99	8.71	8.74	7.55	6.60
Gas ($/Mcf)	1.61	1.86	2.15	1.98	0.91	1.41	1.78	1.94
NGLs ($/Bbl)	9.02	23.72	22.43	16.17	22.42	19.48	18.07	11.46
Combined ($/BOE)	9.24	16.01	16.53	13.11	8.21	9.18	9.23	8.66
Transportation Expense	0.69	0.69	0.70	0.82	0.54	0.50	0.47	0.59
Operating Expenses [(2)]								
Light & Medium Crude Oil ($/Bbl)	11.68	7.03	12.31	9.37	9.93	10.11	10.18	12.33
Heavy Crude Oil ($/Bbl)	18.42	20.60	16.02	14.60	13.61	13.37	12.54	12.02
Gas ($/Mcf)	1.95	1.17	2.05	1.56	1.66	1.69	1.70	2.05
NGLs ($/Bbl)	11.68	7.03	12.31	9.37	9.93	10.11	10.18	12.33
Combined ($/BOE)	14.30	12.39	13.56	11.66	11.75	11.90	11.60	12.16
Netback Received[(3)]								
Light & Medium Crude Oil ($/Bbl)	35.29	99.59	80.62	64.56	56.65	54.10	41.31	39.06
Heavy Crude Oil ($/Bbl)	12.91	54.18	54.71	36.79	20.24	22.06	19.42	19.87
Gas ($/Mcf)	3.51	5.38	6.34	4.45	3.90	2.41	4.06	3.87
NGLs ($/Bbl)	25.07	57.86	57.44	40.94	35.46	31.87	29.33	28.86
Combined ($/BOE)	18.79	46.18	47.98	34.47	24.76	23.27	23.36	23.43

Notes:

(1) Before deduction of royalties.

(2) Operating expenses for light & medium crude oil, gas and NGLs have been allocated based on each product's percentage of their aggregate production.

(3) Netbacks are calculated by subtracting royalties, oil transportation expense and operating expenses from revenues.

The Corporation's crude oil production for the year ended December 31, 2008 was 6% light quality crude oil (32° API or greater), 39% heavy crude oil and 7% natural gas and liquids.

For the year ended December 31, 2008, approximately 60% of the Corporation's gross revenue was derived from crude oil production (including natural gas liquids) and 40% was derived from natural gas production.

DIVIDEND POLICY

The Corporation has not paid any dividends to date on its common shares. The board of directors of the Corporation will determine the timing, payment and amount of dividends, if any, that may be paid by the Corporation from time to time based upon, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other business considerations as the board of directors considers relevant.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of an unlimited number of common shares without nominal or par value and 300,000 preferred shares. The following is a description of the rights, privileges, instructions and conditions attached to the authorized share capital of the Corporation.

Common Shares

The holders of common shares are entitled to one vote at each meeting of holders of common shares. On the liquidation, dissolution or winding-up of the Corporation, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, the holders of the common shares shall be entitled to receive the remaining property and assets of the Corporation. The holders of common shares are entitled to receive, if, as and when declared by the directors of the Corporation, non-cumulative dividends at such rate and payable on such date as may be determined from time to time by the directors of the Corporation.

Preferred Shares

The preferred shares may at any time and from time to time be issued in one or more series, each series to consist of such number of shares, subject to the maximum total number of preferred shares issuable, as may, before the issue thereof, be determined by resolution of the board of directors of the Corporation. Subject to the provisions of the *Business Corporation* Act (Act), the board of directors of the Corporation may by resolution fix from time to time before the issue thereof the designation, rights, privileges, restrictions and conditions attached to each series of the preferred shares.

MARKET FOR SECURITIES

The common shares of the Corporation trade on the Toronto Stock Exchange (the "**TSX**") under the symbol "RE". The following sets forth the price range and trading volume of the Common Shares on the TSX (as reported by the TSX) for the periods indicated.

	Price Range		
	High	Low	Volume
2008			
January	2.90	2.05	503,133
February	3.39	2.36	933,181
March	3.15	2.75	452,171
April	4.10	2.80	742,567
May	4.45	3.70	1,065,133
June	4.60	4.12	824,734
July	4.50	4.20	1,255,819
August	4.50	4.20	678,511
September	4.48	2.80	493,966
October	3.40	1.55	612,465
November	2.15	1.35	351,194
December	1.65	0.61	1,067,382
2009			
January	1.40	0.86	1,240,384
February	1.04	0.65	217,993
March (1-11)	0.75	0.50	181,283

ESCROWED SECURITIES

To the knowledge of the Corporation, no securities of the Corporation are held in escrow.

DIRECTORS AND OFFICERS

The names, provinces and countries of residence, positions and offices with the Corporation, and principal occupation of the directors and officers of the Corporation are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name and Province and Country of Residence	Position and Office Held	Principal Occupation	Director Since
Allen J. Bey[(4)] Alberta, Canada	President, Chief Executive Officer and Director	President and CEO of Rock since January 2004. From January 2003 to January 2004 President and CEO of Rock Energy. From January 1996 until it was sold in July 2001 President and CEO of Avid Oil and Gas Ltd (a public oil and gas company).	October 3, 2003
Peter D. Scott Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and CFO of Rock since January 2004. From March 2003 to January 2004 Vice President, Finance and CFO of Rock Energy. From March 2000 to March 2003 Executive Vice President and CFO of Absolute Software Corporation (a public software development company). From March 1997 to March 2000 Vice President Finance and CFO of Beau Canada Exploration Ltd. (a public oil and gas company).	N/A
Jeffrey G. Campbell Alberta, Canada	Vice President, Operations and Chief Operating Officer	Vice President, Operations and Chief Operating Officer of Rock since November 2007. From January 2002 to August 2007, Vice President, Production, then Executive Vice President (Country Manager) of Seneca Energy Canada Inc. (the Canadian subsidiary of a public energy utility). From July 2001 to December 2001 District Manager of Husky Energy Inc. (a public oil and gas company). From April 1997 to July 2001 Vice President, Production of Avid Oil and Gas Ltd. (a public oil and gas company).	N/A
Arezki Ioughlissen Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Rock since November 2007. From December 2004 to October 2007 Chief Geophysicist of Rock. From May 2002 to December 2004 Geophysical Advisor of Vintage Petroleum Canada Inc. (the Canadian subsidiary of a public oil and gas company). From April 2001 to May 2002 Senior Geophysicist of Rio Alto Exploration (a public oil and gas company). From January 1997 to March 2001 Senior Geophysicist then Chief Geophysicist of Fletcher Challenge Energy Canada (the Canadian subsidiary of a public oil and gas company).	N/A
Grant A. Zawalsky Alberta, Canada	Corporate Secretary	Partner of Burnet, Duckworth & Palmer LLP (lawyers).	N/A

Name and Province and Country of Residence	Position and Office Held	Principal Occupation	Director Since
Stuart G. Clark(1)(2)(3) Alberta, Canada	Director	Independent businessman since November 2001. From November 1998 to November 2001 Vice President Finance and CFO of Storm Energy Inc. (a public oil and gas company). From January 1986 to July 1998 Mr. Clark was employed in various positions of increasing responsibility the last being Executive Vice President and CFO of Pinnacle Resources Ltd. (a public oil and gas company).	January 8, 2004
Peter Malowany(1)(4) Alberta, Canada	Director	Since March 2005 President and from April 2001 to March 2005 partner and Vice President of Morgas Ltd. (a private oil and gas company). From April 1996 to April 2001 partner and Vice President of Newhouse Resource Management Ltd. (a private oil and gas company).	January 8, 2004
Malcolm Adams(3)(4) Alberta, Canada	Director	Since October 2001 Vice President of ARC Financial Corp. (private equity firm). From May 1997 to October 2001 Senior Exploration Engineer of ARC Resources Management Ltd. (manager of ARC Energy Trust, a public oil and gas trust). From June 1994 to May 1997 Reservoir Engineer of Shell Canada Ltd.	September 28, 2007
James K. Wilson(1)(3) Alberta, Canada	Director	Since September 2004 Vice President, Finance and CFO of Grizzly Resources Ltd. (a private oil and gas company). From January 2002 to September 2004 Vice President, Finance and CFO of Archean Energy Ltd. (a private oil and gas company). From March 2000 to October 2001 Senior Vice President, Finance & CFO and Corporate Secretary of Grey Wolf Exploration Inc. (a public oil and gas company). From March 1999 to March 2000 Vice President, Finance and CFO of Maxx Petroleum Ltd. (a public oil and gas company). From January 1998 to September 1998 Executive Vice President, Finance and CFO of Chauvco Resources International Ltd. (a public oil and gas company). From August 1990 to December 1997 Senior Vice President, Finance and Administration & CFO of Chauvco Resources Ltd. (a public oil and gas company).	October 28, 2004

Notes:
(1) Member of the Audit Committee of the Corporation.
(2) Chairman of the Board.
(3) Member of the Compensation, Nomination and Governance Committee of the Corporation.
(4) Member of the Reserves Committee of the Corporation.
(5) The Corporation does not have an Executive Committee of its Board of Directors.

All of the directors and officers of Rock have been engaged for more than five years in their present principal occupations or executive positions with the same companies except as described above.

The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at March 12, 2009, the directors and officers of the Corporation, as a group, beneficially owned, or controlled or directed, directly or indirectly, 2,343,639 common shares or approximately 9.0% of the issued and outstanding common shares of the Corporation.

Corporate Cease Trade Orders or Bankruptcies

No director or officer of the Corporation: (a) is, or within 10 years before the date hereof, has been, a director, chief executive officer or chief financial officer of any other issuer that: (i) was subject to an order that was issued while the director or officer was acting in the capacity as director, chief executive office or chief financial officer; or (ii) was subject to an order that was issued after the director or officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer; or (b) is, or has been within 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets. For the purposes of paragraph (a) above, "order" means a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Penalties or Sanctions

No director, officer or promoter of the Corporation, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, officer or promoter of the Corporation, or a shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual.

Conflicts of Interest

Directors and officers of the Corporation may, from to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. See "Risk Factors".

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Schedule "C". The members of the Audit Committee are Stuart G. Clark, Peter Malowany and James K. Wilson.

Composition of the Audit Committee

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate.

Relevant Education and Experience

Mr. James K. Wilson is the Chairman of the Audit Committee and holds a Bachelor of Commerce degree and a Chartered Accountant designation. Mr. Wilson is currently the Chief Financial Officer of an oil and gas company and has held that position at several predecessor companies. Mr. Wilson has over 26 years of financial experience in the oil and gas industry. Mr. Stuart G. Clark currently serves on several Audit Committees and has previously been the Chief Financial Officer of several public oil and gas companies. Mr. Clark has over 18 years of financial experience in the oil and gas industry and holds a Bachelor of Commerce degree. Mr. Peter Malowany is a professional engineer and has over 30 years experience in the oil and gas industry, many of them at the executive and board level. Mr. Malowany's experience has afforded him the opportunity to become knowledgeable with respect to financial and accounting matters in the oil and gas industry.

Pre-Approval of Policies and Procedures

The Audit Committee, typically on an annual basis, approves a budget for audit and non-audit services to be performed at the Corporation. The budget is set after consultation with management of the Corporation and the Corporation's auditors. The non audit services budget is usually set at the same amount as for audit services. From time to time management of the Corporation may request approval by the committee of additional funding for special projects such as acquisition related advice.

Any changes in accounting policies are discussed in advance of their implementation with either the Chairman of the Audit Committee or the Audit Committee.

External Auditor Service Fees

The aggregate fees billed by the Corporation's external auditor in the last fiscal year for audit services were $71,120 in 2008 ($66,040 in 2007).

Audit and Related Fees

The aggregate fees billed in the last fiscal year for assurance audit related services by the Corporation's external auditor were $31,380 in 2008 ($54,356 in 2007). The services provided consisted of review of quarterly statements and disclosure and review of acquisition related documents.

Tax Fees

The aggregate fees billed in the last fiscal year for professional services rendered by the Corporation's external auditor for tax compliance, tax advice and tax planning were $29,500 in 2008 ($31,000 in 2007).

All Other Fees

The aggregate fees billed in the last fiscal year by the Corporation's external audit for products and services not included under the heading "Audit and Related Fees" and "Tax Fees" were $nil in 2008 ($nil in 2007).

LEGAL PROCEEDINGS

There are no legal proceedings which the Corporation or any subsidiary of the Corporation is or was a party to, or of which any of their property is or was the subject of during the most recent completed financial year of the Corporation, which are material to the Corporation and the Corporation is not aware of any such proceedings that are contemplated or pending.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and senior officers of the Corporation, any shareholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the last three fiscal years and in any proposed transaction which has materially affected or is reasonably expected to materially affect the Corporation.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, there are no material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year but still in effect.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the

Corporation's most recently completed financial year other than GLJ, the Corporation's independent engineering evaluator and KPMG LLP, the Corporation's auditors.

None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them.

KPMG LLP has confirmed that they are independent in accordance with the rules of professional conduct of the Institute of Chartered Accountants.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

HUMAN RESOURCES

The Corporation currently employs 18 full-time employees and utilizes the services of professionals, as required from time to time on a contract or consulting basis. The Corporation intends to add additional professional and administrative staff as the needs arise.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are KPMG LLP, Chartered Accountants, Suite 2700, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

Alliance Trust Company, at its principal offices in Calgary, Alberta is the transfer agent and registrar of the common shares of the Corporation.

RISK FACTORS

An investment in the common shares of the Corporation should be considered speculative due to the nature of the Corporation's businesses and operations, including in particular their involvement in the, acquisition, exploitation, development, production and marketing of crude oil and natural gas and their present stages of development. **Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.**

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

The Corporation (including Medbroadcast as well as Rock Energy) is or has been engaged in one or more of the technology, mining or oil and natural gas business and its operations are subject to certain unique provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation relating to characterization of costs incurred in its business which effects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. The Corporation has reviewed the income tax returns of Medbroadcast with respect to the characterization of the costs incurred in either the technology or the resource property business, as applicable, as well as other matters generally applicable to all corporations including the ability to offset future income against prior year losses. The Corporation (including Medbroadcast as well as Rock Energy) has filed or will file all required income tax returns and believe that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation, but such returns are subject to reassessment. In the event of a successful reassessment of the Corporation (including Medbroadcast as well as Rock Energy) it may be subject to a higher than expected past or future income tax liability as well as potentially interest and penalties and such amount could be material.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The

Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Accounting Policies and Estimates

The Corporation uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed for impairment to ensure that the carrying amount of these costs is recoverable based on expected future cash flows. To the extent that such capitalized costs (net of accumulated depreciation and depletion) less future taxes exceed the present value of estimated future net cash flows from its proved oil and natural gas reserves, those excess costs would be required to be charged to operations. Canadian generally accepted accounting principles ("**GAAP**") require that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the consolidated financial statements of the Corporation. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading prices of the common shares of the Corporation. Under GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a cost-recovery test which is based in part upon estimated future net cash flows from reserves. If net capitalized costs exceed the estimated recoverable amounts, the Corporation will have to charge the amounts of the excess to earnings. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings. The net value of oil and gas properties are highly dependent upon the prices of oil and natural gas. GAAP requires that goodwill balances be assessed at least annually for impairment and that any permanent impairment be charged to net income. A permanent reduction in reserves, decline in commodity prices, and/or reduction in the trading price of the common shares of the Corporation may indicate a goodwill impairment. An impairment would result in a write-down of the goodwill value and a non-cash charge against net income. The calculation of impairment value is subject to management estimates and assumptions. Emerging GAAP surrounding hedge accounting may result in non-cash charges against net income as a result of changes in the fair market value of hedging instruments. A decrease in the fair market value of the hedging instruments as the result of fluctuations in commodity prices and foreign exchange rates may result in a write-down of net assets and a non-cash charge against net income. Such write-downs and non-cash charges may be temporary in nature if the fair market value subsequently increases. Canadian companies will be transitioning to International Financial Reporting Standards ("**IFRS**") as part of Canadian GAAP effective for years beginning after December 31, 2010. The adoption of IFRS in Canada will result in significant changes to current Canadian GAAP and to financial reporting practices followed by the Corporation. The adoption of IFRS may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading prices of the common shares of the Corporation.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations 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 natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide 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 greenhouse gases which will require the Corporation to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and Specified Gas Emitters Regulation. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See "Industry Conditions – Environmental Regulation".

Environmental

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 federal, provincial and local 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 of applicable environmental legislation 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 governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations 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 have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Common Shares of the Corporation.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are 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, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. 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 associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of 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. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. 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 and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows 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.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the board of directors of the Corporation considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

The directors of the Corporation may be engaged and may continue to be engaged in the search for oil and gas interests on their own behalf and on behalf of other companies, and situations may arise where the directors may be in direct competition with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the corporation's governing corporate law statute which require a director of a corporation who is a party to, or is a director or an officer of, or has some material interest in any person who is a party to, a material contract or proposed material contract with the Corporation, disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under such legislation.

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Corporation's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia, and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 19.5% effective January 1, 2008 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in four additional steps: 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

Oil sands projects are now subject to the NRF, and regulated, among others, by the Oil Sands Royalty Regulation, 2009 Oil Sands Allowed Costs (Ministerial) Regulation and the Bitumen Valuation Methodology (Ministerial) Regulation, 2009, all approved by the Government of Alberta on December 10, 2008.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009, and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the P&G Tenure Regulation and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the Corporation's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on Rock's 2008 production it will be entitled to a maximum credit of 50% of royalties payable in the period April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas. The three-point incentive program also includes an investment of $30,000,000 by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and gas wells and to stimulate new activity within the services sector.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

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

Some of the financial incentives in the Strategy include:

- Royalty credits annually towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry. This program has evolved over past years as a result of the Province's stated objective to increase competitiveness, and on March 2, 2009 the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program ("**Program**") which allocates $120 million in royalty credits for oil and gas companies. The Program provides access to royalty credits to oil and gas companies with respect to certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. Companies must apply to the Ministry of Energy and Mines for British Columbia prior to 2:00 p.m. on April 30, 2009 to be considered for approval under the program.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

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

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

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" and "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.

A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government if Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the *Oil and Gas Conservation Act* and the Oil and Gas Conservation Regulations, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the Specified Gas Emitters Regulation, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for in situ oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining its strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and natural gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and natural gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, the Government of British Columbia introduced on July 1, 2008, revenue-neutral carbon tax legislation that is applied to all fossil fuels used in the Province of British Columbia. The tax would be phased in, and the initial rate would be based on CO2e of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government of British Columbia would receive otherwise. On April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* which will allow participation in the Western Climate Initiative cap and trade systems being developed. The system establishes a limit on emissions, and allows regulated emitters to buy/sell emission allowances or offset emits. The emitter is obliged to obtain emission allowances (compliance units) equal to the amount of greenhouse gases emitted within a certain period of time, and that are supposed to be surrendered to the Government of British Columbia as compliance proof.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oil sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and in-situ production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition at this time.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions, if applicable, is contained in the Corporation's Information Circular - Proxy Statement dated March 12, 2008 which relates to the Annual and Special Meeting of Shareholders held on May 14, 2008. Additional financial information is contained in the consolidated financial statements of the Corporation for the year ended December 31, 2008 and the Management's Discussion and Analysis contained in the Corporation's Annual Report for the year ended December 31, 2008.

The Corporation will provide to any person or corporation, upon request to the Corporation:

(a) when the securities of the Corporation are in the course of a distribution pursuant to a preliminary short form prospectus or a short form prospectus:

   (i) one copy of the Corporation's annual information form, together with one copy of any document, or the pertinent pages of any document, incorporated therein by reference;

   (ii) one copy of the comparative financial statements of Rock for its most recently completed financial year in respect of which such financial statements have been issued, together with the report of the auditor thereon, and one copy of any interim financial statements of the Corporation subsequent to the financial statements for Rock's most recent financial year;

(iii) one copy of the management information circular of the Corporation in respect of its most recent annual meeting of shareholders that involved the election of directors or one copy of any annual filing prepared in lieu of that circular, as appropriate, and

(iv) one copy of any other document that is incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, a copy of the documents referred to in clauses (a)(i), (ii) or (iii) above, provided the Corporation may require a payment of a reasonable charge if the request is made by a person or Corporation who is not a security holder of the Corporation.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph are available on the foregoing basis and upon request by contacting the Corporation at its offices at 800, 607 – 8th Avenue S.W., Calgary, Alberta, T2P 0A7, or by phone at (403) 218-4380, fax at (403) 234-0598 or email at info@rockenergy.ca.

SCHEDULE "A"

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the board of directors of Rock Energy Inc. (the "**Company**"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008 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.

3. 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).

4. 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.

5. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us for the year ended December 31, 2008, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) ($'000)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	Corporate Summary March 4, 2009	Canada	$nil	$177,466	$nil	$177,466

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

7. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material; however, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada
March 5, 2009

ORIGINALLY SIGNED BY
Leonard L. Herchen, P.Eng.

SCHEDULE "B"

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

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

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented on Schedule "A" of this Annual Information Form.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves 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 Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

(d) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;

(e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(f) 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; however, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "Allen J. Bey"
Allen J. Bey
President and Chief Executive Officer

(signed) "Jeffrey G. Campbell"
Jeffrey G. Campbell
Vice President, Operations and Chief Operating Officer

(signed) "Peter Malowany"
Peter Malowany
Director and Chairman of the Reserves Committee

(signed) "Stuart G. Clark"
Stuart G. Clark
Director and Chairman of the Board

March 12, 2009

SCHEDULE "C"

ROCK ENERGY INC.

AUDIT COMMITTEE

MANDATE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Rock Energy Inc. ("**Rock**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

a. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Rock and related matters;

b. To provide better communication between directors and external auditors;

c. To enhance the external auditor's independence;

d. To increase the credibility and objectivity of financial reports; and

e. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

a. The Committee will be comprised of at least three (3) directors of Rock or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("**MI 52-110**") unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.

b. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.

c. All of the members of the Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

a. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

b. Satisfy itself on behalf of the Board that Rock's internal control systems are satisfactory for the purposes of:

- identifying, monitoring and mitigating business risks; and

- ensuring compliance with legal, ethical and regulatory requirements.

c. Review the annual and interim financial statements of Rock and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

- reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
- reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
- reviewing accounting treatment of unusual or non-recurring transactions;
- ascertaining compliance with covenants under loan agreements;
- reviewing disclosure requirements for commitments and contingencies;
- reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
- reviewing unresolved differences between management and the external auditors; and
- obtain explanations of significant variances with comparative reporting periods.

d. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Rock's disclosure of all other financial information and will periodically access the accuracy of those procedures.

e. With respect to the appointment of external auditors by the Board:

- recommend to the Board the external auditors to be nominated;
- recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
- on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
- when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
- review and pre-approve any non-audit services to be provided to Rock or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

f. Review with external auditors (and internal auditor if one is appointed by Rock) their assessment of the internal controls of Rock, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Rock and its subsidiaries.

g. Review risk management policies and procedures of Rock (i.e. hedging, litigation and insurance).

h. Establish a procedure for:

- the receipt, retention and treatment of complaints received by Rock regarding accounting, internal accounting controls or auditing matters; and
- the confidential, anonymous submission by employees of Rock of concerns regarding questionable accounting or auditing matters.

i. Review and approve Rock's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Rock.

j. Co-ordinate meetings with the Reserves Committee of the Corporation, the Corporation's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Corporation's evaluation of petroleum and natural gas reserves.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Rock. All employees of Rock are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Rock without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee shall meet at the end of or during each meeting without members of management being present.

6. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

7. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

8. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

9. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

10. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

11. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

12. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.

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PRESS RELEASE

Rock Energy 2008 Year End Results

March 13, 2009, Calgary Alberta: Rock Energy Inc. (TSX:RE) "Rock" is pleased to report its financial and operating results for the three month and twelve month periods ending December 31, 2008.

Rock is a Calgary, Alberta, Canada based crude oil and natural gas exploration, development and production company.

During 2008 Rock accomplished the following key goals:

Drilling Results

In 2008 Rock participated in 33 (24.3 net) wells, resulting in 18 (18.0 net) heavy oil wells, 14 (5.3 net) natural gas wells and 1 (1.0 net) dry and abandoned well, for a success rate of 96 percent on net cased wells. Rock operated 24 of the 33 gross wells drilled in 2008. The 2008 drilling strategy focused on converting reserves in the proved non-producing or undeveloped and probable categories to proved producing, and increasing average daily production rates.

To date in 2009 Rock has drilled 2 (1.3 net) natural gas wells at Saxon and Elmworth, both of which were cased as natural gas wells. The Saxon well is not expected to be placed on production until next winter as the well tested at rates of 250-300 mscf per day. We will proceed with this tie-in next winter in conjunction with our other activities in this area to minimize our costs. The Elmworth well is expected to be completed and tested after spring breakup and should be on production in the third quarter of 2009.

Infrastructure Construction

A key accomplishment in 2008 was the $14 million spent for the construction of natural gas gathering pipelines, and compressor, dehydration and liquids-handling stations to tie-in Rock's natural gas wells at Saxon, Musreau, Kakwa and Elmworth, all of which are contributing to production and cash flow. Infrastructure ownership provides Rock with a strategic advantage in the Saxon area, allowing the Company to conclude a farm-in agreement that added two sections of land with two to three drilling locations.

Reserves and Net Asset Value

Rock increased total company reserves by 9 percent on a proved plus probable basis, to 10.2 million boe at year-end 2008 from 9.3 million boe at year-end 2007, replacing 167 percent of 2008 production. Proved-producing reserves increased by 32 percent in 2008 to 4.7 million boe versus 3.5 million boe in 2007. All-in finding, development and acquisition (FD&A) costs incurred in 2008 averaged $25.13 per boe (proved plus probable). This one-year cost is unacceptably high, but relates to the $14 million spent on infrastructure ($6.49 per boe (proved plus probable)) and a further $7.2 million spent on land and seismic ($3.35 per boe (proved plus probable)). The Company expects to increase reserve bookings with more production history from the new wells and as the full exploration cycle is completed. Rock's three-year average all-in FD&A cost was $18.24 per boe (proved plus probable), which is more representative of true full-cycle costs.

The year-end 2008 reserve report by GLJ Petroleum Consultants Ltd., using its forecasted commodity prices, indicates a value of $177.5 million for Rock's proved plus probable reserves (net present value discounted at 10 percent, before tax). Rock's net asset value is calculated at $5.96 per share (basic), assuming year-end debt of $38.6

million, land of 80,574 net acres at the acquired cost of $15.4 million, no value for seismic, and 25.9 million basic shares outstanding. This represents an increase of 13.6 percent from year-end 2007.

On a cautionary note, applying the current forward-price strip (see Table 1) to the Rock reserve base gives a lower net asset value per share of $4.50 (net present value discounted at 10 percent, before tax). To be even more conservative, the net asset value per share based on the current forward strip generates a net present value (discounted at 20 percent, before tax) of $3.04.

Table 1: Forward Strip Pricing NYMEX

At February 27, 2009

Year	NYMEX WTI (US$/bbl)	AECO (CDN$/MMBtu)	Heavy Oil (CDN$/bbl)	Exchange Rate US$/Cdn$
2009	49.41	5.12	38.53	0.787
2010	55.78	6.59	43.61	0.791
2011	60.62	7.37	48.83	0.794
2012	64.12	7.61	51.29	0.801
2013	66.74	7.70	53.25	0.804
2014	69.21	7.86	55.29	0.804
2015+	+2%/yr	+2%/yr	+2%/yr	0.804

Production Results

Rock's daily production averaged 3,436 boe per day in 2008 compared to 2,198 boe per day in 2007, an increase of 56 percent; Rock exited 2008 with average daily production of approximately 4,000 boe per day. The Company decided to reduce spending in the fourth quarter due to lower commodity prices, which led to production declining to 3,800 boe per day in January. Specifically, Rock has reduced its spending on drilling, and will refrain from working over marginal wells unless it can achieve a short-term payout at current pricing.

Financial Results

In 2008 Rock generated funds from operations of $40.7 million ($1.57 per share) and net income of $1.9 million ($0.07 per share). The Company had capital expenditures of $50.2 million, including a 1.2 million disposition. Total debt was $38.6 million at year-end, against bank lines of $51 million.

2009 Capital Program

Rock's Board of Directors has approved a revised capital budget of $15 million for 2009 based on a price forecast for WTI oil of US$47.00 per barrel and for AECO natural gas of Cdn$5.00 per mcf . This basic budget includes drilling 12 wells during the year to take advantage of the recently announced Alberta royalty initiatives. The remaining funds will be used to acquire seismic and land in order to expand the drilling inventory and reduce our debt levels.

Based on this forecast, Rock's production for 2009 is expected to average 3,200 - 3,400 boe per day, generating funds from operations of $17.5 million or $0.68 per basic share. Debt at year-end would be held constant at $36 million. The planned budget will be reviewed at each quarterly meeting of the Board of Directors and may be expanded if commodity prices improve.

Some of our key initiatives for 2009 include:

- **Continue building Rock's inventory of drilling locations.** Rock's existing core areas of West Central Alberta and Plains offer significant potential for production and reserve adds in plays that we have demonstrated an understanding of, and that can be drilled as commodity prices rise and costs decline.

- **Add a new core area** of operations to our existing base that can further diversify our drilling portfolio and provide top-quartile finding costs and recycle ratios.

- **Deploy small amounts of capital to purchase land and seismic.** This is essential to building our drilling inventory. In the current price environment, we expect to acquire land and seismic at more reasonable prices.

- **Negotiate farm-in deals** that do not require significant drilling commitments before 2010. Many E&P companies will be evaluating their own prospect inventories and will be seeking partners for drilling projects to preserve expiring lands and take advantage of the newly announced Alberta royalty holiday.

- **Focus on operating and administrative cost reductions** in all areas of operations (field and office). Improving efficiencies throughout the Company can be a low-cost way to improve overall margins for the long-term.

- **Pursue corporate acquisitions and mergers** that are accretive to Rock's long-term growth prospects and will provide mass and liquidity for the Company to prosper in the future.

- **Pursue small asset acquisitions** with our excess bank lines within our core areas. Many junior E&P companies have reached the limit of their bank lines and may be willing to sell assets to generate capital to satisfy their loan commitments.

Conclusion

As we enter 2009, Rock is being cautious. The Company is guarding its balance sheet, reducing its debt level, managing its cash flow and striving to capitalize on opportunities that current commodity prices present. Rock's team will continue building its drilling inventory, refine operations to reduce costs, and pursue acquisitions and mergers. In management's experience the best opportunities are captured in the dark seasons. This is a time to capture those opportunities.

Corporate Summary

	Twelve months ended December 31, 2008	Twelve months ended December 31, 2007	Three months ended December 31, 2008	Three months ended December 31, 2007
Financial				
Oil and natural gas revenue ($000)	**$80,138**	$ 36,042	**$15,670**	$ 11,124
Funds from operations ($000) [1]	**$40,747**	$ 15,189	**$5,516**	$ 4,735
Per share – basic	**$1.57**	$ 0.72	**$0.21**	$ 0.18
– diluted	**$1.57**	$ 0.72	**$0.21**	$ 0.18
Net income (loss) ($000)	**$1,891**	$ 561	**$(2,083)**	$ 290
Per share – basic	**$0.07**	$ 0.03	**$(0.08)**	$ 0.01
– diluted	**$0.07**	$ 0.03	**$(0.08)**	$ 0.01
Capital expenditures, net ($000)	**$50,172**	$ 53,702	**$9,256**	$ 7,488

	As at December 31, 2008	As at December 31, 2007
Working capital including bank debt ($000)	**$ (38,622)**	$ (29,072)
Common shares outstanding (000)	**25,900**	25,878
Options outstanding (000)	**1,744**	2,308

	Twelve months ended December 31, 2008	Twelve months ended December 31, 2007	Three months ended December 31, 2008	Three months ended December 31, 2007
Operations				
Average daily production				
Light crude oil *(bbls/d)*	**193**	215	**169**	206
Heavy crude oil *(bbls/d)*	**1,329**	1,194	**1,537**	1,323
NGL *(bbls/d)*	**239**	79	**298**	81
Natural gas *(mcf/d)*	**10,048**	4,261	**11,731**	6,372
Total *(boe/d)*	**3,436**	2,198	**3,959**	2,672
Average product prices				
Light crude oil *(Cdn$/bbl)*	**$95.86**	$ 70.69	**$57.20**	$ 81.66
Heavy crude oil *(Cdn$/bbl)*	**$71.58**	$ 41.18	**$40.17**	$ 42.56
NGL *(Cdn$/bbl)*	**$74.15**	$ 60.00	**$45.78**	$ 67.81
Natural gas *(Cdn$/mcf)*	**$8.72**	$ 6.96	**$7.27**	$ 6.64
BOE *(Cdn$/boe)*	**$63.73**	$ 44.93	**$43.02**	$ 45.26
Operating netback *(Cdn$/boe)*	**$36.33**	$ 23.79	**$18.79**	$ 24.77

[1] Funds from operations and funds from operations per share are not terms under generally accepted accounting principles (GAAP), and represent cash generated from operating activities before changes in non-cash working capital. Rock considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future growth through capital investment. Funds from operations may not be comparable with the calculation of similar measures for other companies. Funds from operations per share is calculated using the same share basis which is used in the determination of net income/(loss) per share.

Financial Information and Analysis

ROCK ENERGY INC. ("ROCK" OR THE "COMPANY") is a publicly traded energy company engaged in the exploration for and the development and production of crude oil and natural gas, primarily in Western Canada. Rock's corporate strategy is to grow and develop an oil and natural gas exploration and production company through internal operations and acquisitions.

Rock evaluates its performance based on net income, field netback, funds from operations and finding and development costs. Funds from operations are a measure used by the Company to analyze operations, performance, leverage and liquidity. Field netback is a benchmark used in the oil and natural gas industry to measure the contribution of the oil and natural gas operations following the deduction of royalties, transportation costs and operating expenses. Finding and development costs are another benchmark used in the oil and natural gas industry to measure the capital costs incurred by the Company to find and bring reserves on-stream.

Rock faces competition in the oil and natural gas industry for resources, including technical personnel and third-party services, and capital financing. The Company is addressing these issues through the addition of personnel with the expertise to develop opportunities on existing lands and to control operating and administrative cost structures. Rock also seeks to obtain the best price available based on the quality of its produced commodities.

The following financial information and analysis is dated March 12, 2009 and is management's assessment of Rock's historical, financial and operating results, together with future prospects, and should be read in conjunction with the audited consolidated financial statements of Rock for the year ended December 31, 2008.

BASIS OF PRESENTATION

Certain financial measures referred to in this discussion, such as funds from operations and funds from operations per share, are not prescribed by generally accepted accounting principles (GAAP). Funds from operations is a key measure that demonstrates the ability to generate cash to fund expenditures. Funds from operations is calculated by taking the cash provided by operations from the consolidated statement of cash flows and adding back changes in non-cash working capital. Funds from operations per share is calculated using the same methodology for determining net income per share. These non-GAAP financial measures may not be comparable to similar measures presented by other companies. These financial measures are not intended to represent operating profits for the period nor should they be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with GAAP. The reconciliation between funds from operations and cash flow from operations for the three months and years ended December 31, 2008 and 2007 is presented in the table below.

($thousands)	**12 Months Ended 12/31/08**	12 Months Ended 12/31/07	3 Months Ended 12/31/08	3 Months Ended 12/31/07
Funds from operations	**$40,747**	$15,189	$5,516	$4,735
Changes in non-cash working capital	**843**	(1,035)	745	251
Cash flow from operations	**$41,590**	$14,154	$6,261	$4,986

Management uses certain industry benchmarks such as field netback to analyze financial and operating performance. Field netback has been calculated by taking oil and gas revenue less royalties, operating costs and transportation costs. This benchmark does not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other companies. Management considers field netback as an important measure to demonstrate profitability relative to commodity prices.

All barrels of oil equivalent (boe) conversions in this report are derived by converting natural gas to oil at the ratio of six thousand cubic feet (mcf) of natural gas to one barrel (bbl) of oil. Certain financial values are presented on a boe basis and such measurements may not be consistent with those used by other companies. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf to one boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.

Certain statements and information contained in this document, including but not limited to management's assessment of Rock's plans and future operations, production, reserves, revenue, commodity prices, operating and administrative expenditures, future income taxes, wells drilled, acquisitions and dispositions, funds from operations, capital expenditure programs and debt levels, contain forward-looking statements. All statements other than statements of historical fact may be forward-looking statements. These statements, by their nature, are subject to numerous risks and uncertainties, some of which are beyond Rock's control, including the effect of general economic conditions, industry conditions, regulatory and taxation regimes, volatility of commodity prices, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel, any of which may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such forward-looking statements, although considered reasonable by management at the time of preparation, may prove to be incorrect and actual results may differ materially from those anticipated in the statements made and, therefore, should not unduly be relied on. These statements speak only as of the date of this document. Rock does not intend and does not assume any obligation to update these forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law.

All financial amounts are in thousands of Canadian dollars unless otherwise noted.

GUIDANCE AND OUTLOOK

The Company issued guidance on November 13, 2008 for projected 2008 and 2009 results. The table below provides the guidance for 2008 with actual results.

2008 Guidance

	2008 Guidance	Actual	Difference
2008 Production *(boe/d)*			
Annual	3,400-3,600	3,436	0%
Exit (December average)	4,300-4,500	4,055	(8)%
2008 Funds from Operations			
Annual	$43 million	$40.7 million	(5)%
Annual *(per share)*	$1.66	$1.57	(5)%
2008 Capital Budget			
Expenditures	$52 million	$50.2 million	(3)%
Gross wells drilled	34	33	(3)%
Total net debt at year end	$38 million	$38.6 million	2%
Pricing (Fourth Quarter)			
Oil – WTI	US$70.00/bbl	US$58.73/bbl	(16)%
Natural gas – AECO	$7.00/mcf	$6.70/mcf	(4)%
US/Cdn dollar exchange rate	0.85	0.825	(3)%

Production average for the year was within the guidance range however the exit rate was below guidance primarily as the compressor expansion at Elmworth in the West Central core area did not come on-stream until mid first quarter 2009 compared to our forecast start date of mid November 2008 and we elected to leave approximately 100 bbls/day of heavy oil shut-in for maintenance purposes given the low heavy oil price. Funds flow from operations was below guidance due to lower prices and production in the fourth quarter of 2008. Capital expenditures were lower than forecast as 1 (1.0 net) well at Saxon didn't start drilling until the first quarter of 2009. As a result of lower funds from operations, partially offset by lower capital expenditures, debt levels were slightly above guidance levels.

Guidance for 2009 has been updated to reflect results from the winter drilling program, well performance and lower expected commodity prices. The table below updates the Company's previous guidance that was issued November 13, 2008.

	2009 Previous Guidance	2009 Revised Guidance	Change
2009 Production *(boe/d)*			
Annual	4,100-4,300	3,200-3,400	(21)%
Exit	4,400-4,600	3,100-3,300	(29)%
2009 Funds from Operations			
Annual	$33 million	$17.5 million	(47)%
Annual – *(per share)*	$1.28	$0.68	(47)%
2009 Capital Budget			
Expenditures	$37.5 million	$15 million	(60)%
Gross wells drilled	35	12	(66)%
Total net debt at year-end	$42.5 million	$36.1 million	(15)%
Pricing (Annual average)			
Oil – WTI	US$70.00/bbl	US$47.00/bbl	(33)%
Natural gas – AECO	Cdn$7.00/mcf	Cdn$5.00/mcf	(29)%
US/Cdn dollar exchange rate	0.85	0.80	(6)%

The decline in commodity prices has caused Rock to significantly cut back on capital expenditures. If these commodity prices persist the Company anticipates drilling 12 (10.7 net) wells in 2009 of which 2 (1.3 net) wells were drilled in the first quarter of 2009. Furthermore wells that require servicing are likely to be delayed unless a short payout period can be achieved on the expected service expenditures. Rock anticipates acquiring land and seismic (current budget of $1.8 million) in order to develop additional drilling inventory which can be accessed once commodity prices improve. Rock anticipates that Lloyd blend heavy oil prices need to approach $50.00/bbl and natural gas prices need to exceed $7.00/mcf in order to significantly expand our drilling activities. In the current environment Rock anticipates natural production declines and delayed well servicing will cause 2009 production to average approximately 3,300 boe/day with exit rates of approximately 3,200 boe/day. The combined reduction in commodity prices and production is expected to result in funds from operations for 2009 of approximately $17.5 million ($0.68 per basic share). Royalty rates are expected to average 15 percent in this price environment and after taking into account the new initiatives recently announced by the Alberta government (down from 26 percent in the previous forecast), operating costs are expected to average 5 percent higher than previously forecast at $12.85/boe based on recent experience and net G&A expense of $2.60/boe (up from $2.00/boe in our previous guidance due to lower forecast production). Debt to funds from operations ratio is expected to be about 2.1 times on annual basis, falling from a high of 2.9 times in the first quarter down to 1.7 times in the fourth quarter. Management believes in the current commodity price cycle capital expenditures should be less than funds from operations, with capital expenditures directed at preserving the reserve base. We will continue to monitor, debt availability, funds from operations and capital expenditures in order to chart a prudent course of action and stay within our borrowing capacity.

PRODUCTION and PRICES

Production by Product

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Change
Natural gas *(mcf/d)*	**10,048**	4,261	**136%**	11,731	6,372	84%
Light and medium oil *(bbls/d)*	**193**	215	**(10)%**	169	206	(18)%
Heavy oil *(bbls/d)*	**1,329**	1,194	**11%**	1,537	1,323	16%
NGL *(bbls/d)*	**239**	79	**203%**	298	81	268%
Total (boe/d) *(6:1)*	**3,436**	2,198	**56%**	3,959	2,672	48%

Production by Area

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Change
West Central Alberta *(boe/d)*	**1,722**	642	**168%**	2,090	1,041	101%
Plains *(boe/d)*	**1,362**	1,196	**14%**	1,563	1,325	18%
Other *(boe/d)*	**352**	360	**(2)%**	306	306	0%
Total (boe/d) *(6:1)*	**3,436**	2,198	**56%**	3,959	2,672	48%

Production increased 56 percent for the year ended December 31, 2008 over the prior year due to new natural gas and NGL production from Saxon in the West Central core area, production acquired and new drilling at Elmworth, and increased heavy oil production. New production at Saxon (West Central core area) reflects our efforts in the deep basin area over the last several years. Land and seismic was acquired in the summer of 2007 and the first wells were drilled and tied-in during the 2007-08 winter drilling season resulting in new production coming on-stream in May 2008. Rock still has 4 – 6 additional locations in inventory. The Company's Elmworth property in the West Central core area was acquired with the Greenbank acquisition at the end of the third quarter of 2007. Production at the time of acquisition was approximately 500 boe/day (92 percent natural gas) and through drilling this past summer has grown to more than 700 boe/day. Start up of a compressor expansion scheduled for mid November 2008 was delayed until early February 2009 and is expected to add additional production. Heavy oil production increases were driven by drilling which primarily occurred in third quarter of 2008. Of the 18 (18.0 net) cased wells drilled, 14 (14.0 net) are producing at expected rates or better, 1 (1.0 net) is waiting on recompletion and 3 (3.0 net) have declined significantly within months of production and are currently shut-in.

Production increased by 48 percent in the fourth quarter of 2008 from the same period last year and reached 4,000 boe/day during the quarter due to the Company's drilling activity at Saxon and Elmworth in the West Central core area and heavy oil in the Plains core area. Later in the fourth quarter and continuing in the first quarter of 2009 the Company has delayed servicing of some heavy oil wells and delayed the drilling of any additional wells subsequent to the Saxon and Elmworth wells that were drilled in January 2009. As a result current production is approximately 3,700 boe/day. New production from the Elmworth drills plus the start up of additional compression at Elmworth will help offset production declines and delayed servicing.

Product Prices

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Realized Product Prices						
Natural gas *($/mcf)*	**8.72**	6.96	25%	7.27	6.64	9%
Light and medium oil *($/bbl)*	**95.86**	70.69	36%	57.20	81.66	(30)%
Heavy oil *($/bbl)*	**71.58**	41.18	74%	40.17	42.56	(6)%
NGL *($/bbl)*	**74.15**	60.00	24%	45.78	67.81	(32)%
Combined average ($/boe) *(6:1)*	**63.73**	44.93	42%	43.02	45.26	(5)%

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Average Reference Prices						
Natural gas – Henry Hub Daily Spot *(US$/mmbtu)*	**8.88**	6.98	27%	6.47	7.01	(8)%
Natural gas – AECO C Daily Spot *($/mcf)*	**8.16**	6.45	27%	6.70	6.15	9%
Oil – WTI Cushing, Oklahoma *(US$/bbl)*	**99.65**	72.31	38%	58.73	90.68	(35)%
Oil – Edmonton Light *($/bbl)*	**102.16**	76.35	34%	63.21	86.42	(27)%
Heavy oil – Lloydminster blend *($/bbl)*	**82.87**	51.63	61%	48.61	55.49	(12)%
US/Cdn $ exchange rate	**0.943**	0.935	1%	0.825	1.019	(19)%

The first three quarters of 2008 are in contrast to the last quarter of 2008 with respect to commodity price realizations. Rock experienced very strong pricing in the former periods and continual deterioration in prices, particularly for oil based products, in the latter period. The Company realized its lowest prices over the year in December 2008 of $34.60/boe versus the highest realized prices of $89.57/boe in July 2008.

Heavy oil prices were significantly higher for the year ended 2008 compared to 2007 based on the strength of the first three quarters while prices in the fourth quarter of 2008 were 6 percent lower than the same period in 2007. The drop in WTI prices in the fourth quarter were partially offset by narrower price differentials to Edmonton par pricing (36 percent in Q4 2008 versus 51 percent in Q4 2007). WTI prices are currently around US$45/bbl and heavy oil differentials appeared to have narrowed from December 2008 levels resulting in an current estimated heavy oil wellhead price of $35/bbl (compared to $19/bbl for December 2008).

Canadian natural gas prices for the year and fourth quarter of 2008 were higher than 2007. Similar to oil, natural gas prices were higher for the first three quarters of 2008 as higher U.S. prices more than offset the stronger Canadian dollar during this period. However in the fourth quarter of 2008, the weaker Canadian dollar and narrower pricing differential more than offset the decline in US gas prices resulting in a higher Canadian gas price than in the fourth quarter of 2007. Late in the fourth quarter and continuing into 2009, natural gas prices (both in the US and Canada) have continued to decline as the combination of reduced industrial demand due to a poor economy and increased US production from shale gas has more than offset the effect of a colder winter and the lack of liquefied natural gas imports. As a result storage levels compared to last year have gone from a year over year deficit entering the heating season in November 2008 to a surplus currently. Canadian natural gas prices at AECO are currently about $4.25/mcf, approximately 35 percent lower than the $6.60/mcf for December 2008. Rock has not hedged any commodity prices at this time.

REVENUE

The vast majority of the Company's revenue is derived from oil and natural gas operations. Other income is primarily royalty interest revenue.

Oil and Natural Gas Revenue

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Natural gas	**$ 32,052**	$ 10,830	196%	$ 7,845	$ 3,890	102%
Light and medium oil	**6,780**	5,538	22%	889	1,547	(43)%
Heavy oil	**34,813**	17,951	94%	5,681	5,180	10%
NGL	**6,493**	1,724	277%	1,255	507	148%
	80,138	36,042	122%	15,670	11,124	41%
Other revenue	**$ 138**	$ 79	75%	$76	$ 12	533%

Oil and natural gas revenue more than doubled for the year ended December 31, 2008 over 2007 due to higher realized prices and production levels. For the fourth quarter of 2008 oil and natural gas revenue increased by 41 percent from the same period in 2007 as higher production and higher natural gas prices more than offset the decrease in oil prices.

ROYALTIES

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Royalties	**$17,094**	$7,035	143%	$3,366	$2,017	67%
As a percentage of oil and natural gas revenue	**21.3%**	19.5%	9%	21.6%	18.1%	19%
Per boe *(6:1)*	**$13.59**	$8.77	55%	$9.24	$8.21	13%

Royalties increased for the year and quarter ended December 31, 2008 over the prior year periods due to higher production levels and higher prices. Alberta Royalty Tax Credits (ARTC), which was cancelled effective January 1, 2007, impacted both the fourth quarter of 2008 and 2007. The fourth quarter of 2008 included a charge of $72 as a result of an ARTC audit on previously acquired properties and the fourth quarter of 2007 included a $459 benefit as companies with off-calendar (non-December 31) tax year-ends were allowed to benefit from a full calendar year of ARTC. Without the ARTC benefit the royalty rates for 2007 would have been 22.2 percent for the quarter and 20.8 percent for the year.

OPERATING EXPENSES

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Operating expense	**$ 16,456**	$ 9,505	73%	$ 5,207	$ 2,889	80%
Transportation costs	**905**	420	114%	251	130	89%
	17,361	9,925	75%	5,458	3,019	81%
Per boe *(6:1)*	**$13.81**	$12.37	11%	$14.99	$12.28	22%

Operating expenses for the year and quarter ended December 31, 2008 increased over 2007 primarily due to higher production and per unit costs. Heavy oil operations experienced increased cost pressures in 2008 as a result of higher fuel, trucking and service costs compared to the prior year. Fourth quarter 2008 heavy oil operating costs were also negatively impacted by extremely cold weather in December 2008 which lead to higher fuel usage. As a result heavy oil per boe operating costs increased in 2008 to 17.60/boe (18.42/boe for the fourth quarter of 2008) from

12.90/boe in 2007 (13.61/boe for the fourth quarter of 2007). West Central operations tend to have lower operating costs, particulary at Elmworth, which helps lower the corporate average per boe. Transportation costs increased as a result of the properties acquired at the end of third quarter of 2007.

GENERAL and ADMINSTRATIVE (G&A) EXPENSE

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Gross	**$ 4,924**	$ 4,791	3%	$ 1,421	$ 1,593	(11)%
Per boe *(6:1)*	**3.92**	5.97	(34)%	3.90	6.48	(40)%
Capitalized	**1,592**	2,004	(21)%	400	589	(32)%
Per boe *(6:1)*	**1.27**	2.50	(49)%	1.10	2.39	(54)%
Overhead recoveries	**96**	48	100%	30	49	(39)%
Per boe *(6:1)*	**0.08**	0.06	33%	0.08	0.21	(62)%
Net	**3,236**	2,739	18%	991	955	4%
Per boe *(6:1)*	**2.57**	3.41	(25)%	2.72	3.88	(30)%

G&A expense increased on an absolute basis in 2008 over 2007 but declined on a per boe basis. Costs increased due to the higher overall cost environment as well as consulting costs associated with higher activity levels. In the fourth quarter of 2008 the Company recorded $59 of bad debt expense related to prior acquisitions. Rock capitalizes certain G&A expenses based on personnel involved in exploration and development initiatives, including salaries and related overhead costs.

INTEREST EXPENSE

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Interest expense	**$ 1,565**	$ 1,157	35%	$ 331	$ 417	(21)%
Per boe *(6:1)*	**$1.24**	$1.44	(14)%	$0.91	$1.70	(46)%

Interest expense increased for the year ended 2008 over the 2007 period due to higher average bank debt ($31.4 million for 2008 versus $18.5 million for 2007), partially offset by lower interest rates. For the fourth quarter of 2008 lower average interest rates more than offset the increase in average bank debt ($32.6 million for fourth quarter of 2008 versus $26.2 million for the fourth quarter of 2007) resulting in lower interest expense. Bank debt increased as capital expenditures, excluding acquisitions, exceeded funds from operations and were funded through the Company's bank facility.

DEPLETION, DEPRECIATION and ACCRETION (DD&A)

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
D&D expense	**$ 27,849**	$ 13,989	99%	$ 7,734	$ 5,021	54%
Per boe *(6:1)*	**$22.15**	$17.44	27%	$21.24	$20.42	4%
Accretion expense	**$ 260**	$ 154	69%	$ 71	$ 48	48%
Per boe *(6:1)*	**$0.21**	$0.19	11%	$0.19	$0.20	(5)%

Depletion and depreciation expense for the year and quarter ended December 31, 2008 increased over the prior year periods due to higher production and higher cost reserve additions in 2008. The Company spent relatively more capital in the West Central core area (including approximately $14 million of infrastructure costs) which tends to have higher cost reserve additions than the Plains core area.

The Company's asset retirement obligation (ARO) represents the present value of estimated future costs to be incurred to abandon and reclaim the Company's wells and facilities. The discount rate used is 8 percent.

Accretion represents the change in the time value of ARO. The underlying ARO may be increased over a period based on new obligations incurred from drilling wells, constructing facilities or acquiring operations. Similarly, this obligation can also be reduced as a result of abandonment work undertaken and reducing future obligations. During the year ended December 31, 2008 capital programs net of dispositions increased the underlying ARO by $491 (December 31, 2007 – $1,592) and actual expenditures on abandonments were $94 (December 31, 2007 – $nil).

INCOME TAX

The Company pays Saskatchewan resource capital taxes based on its production in the province. Rock does not have current income tax payable and does not expect to pay current income taxes in 2009 as the Company and its subsidiaries had estimated resource and other pools available at December 31, 2008 (after the allocation of deferred partnership income) of approximately $114.7 million as set out below:

CEE	$ 28.2 million
CDE	34.6 million
COGPE	10.5 million
UCC	29.5 million
Loss carry-forwards	10.9 million
Other	1.0 million
Total	$ 114.7 million

FUNDS FROM OPERATIONS and NET INCOME/(LOSS)

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Funds from operations	**$40,747**	$15,189	168%	$5,516	$4,735	16%
Per boe *(6:1)*	**$32.40**	$18.93	71%	$15.15	$19.26	(21)%
Per share:						
Basic	**$1.57**	$ 0.72	118%	$0.21	$ 0.18	17%
Diluted	**$1.57**	$ 0.72	118%	$0.21	$ 0.18	17%
Net income (loss)	**$1,891**	$561	237%	$(2,083)	$290	(818)%
Per boe *(6:1)*	**$1.50**	$0.70	114%	$(5.72)	$1.18	(585)%
Per share:						
Basic	**$0.07**	$0.03	133%	$(0.08)	$0.01	(900)%
Diluted	**$0.07**	$0.03	133%	$(0.08)	$0.01	(900)%
Weighted average shares outstanding:						
Basic	**25,885**	21,239	22%	25,900	25,847	0%
Diluted	**25,923**	21,239	22%	25,900	25,847	0%

The Company issued 6.1 million shares at September 28, 2007 to acquire Greenbank Energy Ltd. which is the primary reason for the increase in weighted average shares outstanding for 2008 versus 2007.

Funds from operations for the year ended December 31, 2008 more than doubled over 2007 as production and price increases more than offset the increase in royalties, operating, G&A and interest costs. On a per-boe basis, 2008 funds from operations increased by 71 percent from 2007 primarily for the same reasons except for the reduction in

G&A and interest costs. For the fourth quarter of 2008 funds from operations increased by 16 percent on an absolute basis from the prior year's periods primarily as the increase in production more than offset the increase in royalties and G&A costs and decreases in prices. On a per boe basis funds from operations for the fourth quarter of 2008 decreased 21 percent from the prior year due to lower prices, higher royalties and operating costs partially offset by a decrease in G&A and interest costs. On a per share basis, funds from operations increased 118 percent in 2008 versus 2007 and increased 17 percent in the fourth quarter of 2008 over the same quarter in 2007. The Company posted a 237 percent increase in net income for the year ended 2008 versus 2007 despite higher depletion expense combined with the write-off of goodwill in the third quarter. Higher depletion expense caused Rock to post a net loss for the fourth quarter of 2008 compared to net income for the prior year period.

CAPITAL EXPENDITURES

($000)	**12 Months Ended 12/31/08**	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Land	**$ 5,688**	$ 3,723	52%	$ 887	$ 457	94%
Seismic	**1,614**	1,359	19%	487	56	777%
Drilling and completions	**28,004**	15,799	68%	8,407	4,801	51%
Facilities & natural gas gathering systems (1)	**14,095**	1,584	1,932%	(88)	1,431	(113)%
Capitalized G&A	**1,592**	2,004	(21)%	400	589	(32)%
Total operations	**$ 50,993**	$ 24,469	108%	$ 10,093	$ 7,334	38%
Property acquisitions (dispositions) (2)	**(1,243)**	28,127	(104)%	Nil	Nil	n/a
Well site facilities inventory	**344**	94	266%	(833)	(19)	4,381%
Office equipment	**78**	1,012	(92)%	(4)	173	(102)%
Total (net of acquisitions and dispositions)	**$ 50,172**	$ 53,702	(7)%	$ 9,256	$ 7,488	24%

(1) Note items have been reclassified from drilling and completion costs to facilities and natural gas gathering systems to better reflect spending categories.

(2) Property acquisitions for 2007 have been restated from the third quarter 2007 report to be presented as the amount allocated to property plant and equipment versus the consideration paid.

Capital expenditures for operations more than doubled for the year ended December 31, 2008 compared to 2007 as Rock drilled 33 (24.3 net) wells in 2008 versus 16 (12.2 net) wells in 2007. Facilities and natural gas gathering expenditures also increased due to the compression and pipeline facilities that were constructed and brought on stream at Saxon in the first half of 2008 and due to the completion of tie-in operations in the Musreau and Kakwa areas in the first quarter of 2008.

Plains core area drilling is broken down as follows over the last two years:

	2008	2007
Heavy oil	18 (18.0 net)	8 (8.0 net)
Natural gas	nil	1 (0.9 net)
Dry hole	1 (1.0 net)	1 (1.0 net)
Total	19 (19.0 net)	10 (9.9 net)

All of the heavy oil wells were placed on production in 2008 which increased production from 1,140 bbl/day in January 2008 to 1,440 bbl/day in December 2008.

West Central core area drilling is broken down as follows over the last two years:

	2008	2007
Saxon	1 (1.0 net)	1 (1.0 net)
Tony Creek	2 (0.9 net)	nil
Girouxville	2 (0.9 net)	nil
Musreau/Kakwa	1 (0.2 net)	3 (0.9 net)
Markerville	1 (0.2 net)	nil
Elmworth	7 (2.1 net)	1 (0.3 net)
Dry hole	nil	1 (0.1 net)
Total	14 (5.3 net)	6 (2.3 net)

Rock operated 5 (2.5 net) of the West Central wells in 2008 compared to 2 (1.3 net) wells in 2007. All of the wells drilled in 2008 were brought on-stream in 2008 except for 2 (0.6 net) Elmworth wells which were delayed until the first quarter of 2009 behind a compression expansion. West Central core area production has increased from 1,070 boe/day in January 2008 to 2,300 boe/day in December 2008 with the majority of the production increase coming from Saxon and Elmworth.

Land and seismic expenditures increased in 2008 versus 2007 as the Company added undeveloped acreage and acquired seismic at Elmworth and Saxon in the West Central core area and in the Plains core area. Total net capital expenditures decreased to $50.2 million in 2008 versus $53.7 million in 2007 as minor non-core property dispositions were completed in 2008 versus the acquisition of Greenbank in 2007.

LIQUIDITY AND CAPITAL RESOURCES

Rock's current approved capital budget for 2009 projects spending of $15 million. In 2009 funds from operations is expected to be approximately $17.5 million. Approximately 30 percent of the capital budget is expected to be spent in the first four months of the year with the majority of these costs already incurred at Saxon. The balance of the budget is expected to be spent after spring break-up with almost of half it being spent in the third quarter of 2009. At year-end 2008 Rock had debt of $39 million against bank line of $51 million. The Company's debt-to-funds from operations ratio was 0.9:1 at year-end based on annual 2008 results; however this ratio has risen to 1.75:1 based on annualized fourth quarter funds from operations. The ratio is expected to rise again in 2009 to approximately 2.9:1 in the first quarter but falling to 1.7:1 in the fourth quarter and averaging 2.1:1 on an annual basis based on current projections.

The projected debt-to-funds from operations ratio is higher than our target of 1.5:1 as commodity prices have fallen significantly since the third quarter of 2008, Rock's wellhead prices have decreased over 50 percent from a high of $89.57/boe in July 2008 to $34.60/boe in December 2008. As a result, we plan to restrict capital expenditures to be less than funds from operations which should reduce bank debt from year-end 2008 levels. Should commodity prices fall below our current projections, we would look at reducing capital expenditures further and expect to shut-in operations that are not producing positive field netback.

The Company has a demand operating loan facility with a Canadian chartered bank. The facility is subject to the bank's valuation of the Company's oil and natural gas assets and the credit currently available is $51 million. The facility bears interest at the bank's prime rate or at the prevailing bankers' acceptance rate plus an applicable bank fee, which varies depending on the Company's debt-to-funds from operations ratio. The facility also bears a standby charge for undrawn amounts. The facility is secured by a first ranking floating charge on all real property of the Company, its subsidiary and partnership and a general security agreement. The next annual review for the facility is scheduled to be completed by April 30, 2009. As at March 11, 2009 approximately $32.8 million was drawn under the facility.

SELECTED ANNUAL DATA

The following table provides selected annual information for Rock:

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	12 Months Ended 12/31/06
Production *(boe/d)*	**3,436**	2,198	2,098
Oil and natural gas revenues ($000)	**$ 80,138**	$ 36,042	$ 33,156
Average realized price *($/boe)*	**$ 63.73**	$ 44.93	$ 43.27
Royalties *($/boe)*	**$ 13.59**	$ 8.77	$ 8.98
Operating expense *($/boe)*	**$ 13.81**	$ 12.37	$ 12.08
Field netback *($/boe)*	**$ 36.33**	$ 23.79	$ 22.21
Net G&A expense ($000)	**$ 3,236**	$ 2,739	$ 2,278
Stock-based compensation ($000)	**$ 1,158**	$ 931	$ 1,188
Funds from operations ($000)	**$ 40,747**	$ 15,189	$ 13,867
Per share – basic	**$ 1.57**	$ 0.72	$ 0.71
Per share – diluted	**$ 1.57**	$ 0.72	$ 0.71
Net income (loss)	**$ 1,891**	$561	($884)
Per share – basic	**$0.07**	$0.03	($0.05)
Per share – diluted	**$0.07**	$0.03	($0.05)
	As at 12/31/08	As at 12/31/07	As at 12/31/06
Total assets	**$ 150,510**	$ 130,495	$ 85,380
Total liabilities	**$ 61,488**	$ 44,301	$ 24,901

SELECTED QUARTERLY DATA

The following table provides selected quarterly information for Rock:

	3 Months Ended 12/31/08	3 Months Ended 09/30/08	3 Months Ended 06/30/08	3 Months Ended 03/31/08	3 Months Ended 12/31/07	3 Months Ended 09/30/07	3 Months Ended 06/30/07	3 Months Ended 03/31/07
Production *(boe/d)*	**3,959**	3,526	3,454	2,798	2,672	1,965	2,036	2,114
Oil and natural gas revenues *($000)*	**$15,670**	$24,424	$24,756	$15,294	$11,124	$8,106	$8,279	$8,553
Average realized price *($/boe)*	**$43.02**	$75.27	$78.80	$60.06	$45.26	$44.85	$44.66	$44.84
Royalties *($/boe)*	**$9.24**	$16.02	$16.53	$13.11	$8.21	$9.18	$9.23	$8.66
Operating expense *($/boe)*	**$14.99**	$13.08	$14.26	$12.48	$12.28	$12.38	$12.10	$12.75
Field netback *($/boe)*	**$18.79**	$46.17	$48.01	$34.47	$24.77	$23.29	$23.33	$23.43
Net G&A expense *($000)*	**$991**	$687	$765	$793	$955	$528	$530	$726
Stock-based compensation *($000)*	**$239**	$312	$315	$292	$216	$207	$241	$267
Funds from operations *($000)*	**$5,516**	$13,906	$13,785	$7,540	$4,735	$3,397	$3,536	$3,521
Per share – basic	**$0.21**	$0.54	$0.53	$0.29	$0.18	$0.17	$0.18	$0.18
Per share – diluted	**$0.21**	$0.53	$0.53	$0.29	$0.18	$0.17	$0.18	$0.18
Net income (loss) *($000)*	**$(2,083)**	($1,266)	$4,020	$1,220	$290	$15	($117)	$373
Per share – basic	**($0.08)**	($0.05)	$0.16	$0.05	$0.01	$0.00	($0.01)	$0.02
Per share – diluted	**($0.08)**	($0.05)	$0.15	$0.05	$0.01	$0.00	($0.01)	$0.02
Capital expenditures *($000)*	**$9,256**	$18,174	$6,345	$16,398	$7,488	$8,367	$2,552	$7,184
	As at 12/31/08	As at 09/30/08	As at 06/30/08	As at 03/31/08	As at 12/31/07	As at 09/30/07	As at 06/30/07	As at 03/31/07
Total debt *($000)* [1]	**$38,622**	$34,903	$30,528	$37,933	$29,072	$26,589	$15,268	$16,242

(1) Total debt includes bank debt and any working capital deficiency.

Production for the fourth quarter of 2008 increased 12 percent over the preceding quarter and has continued to grow since the third quarter of 2007 mostly due to our drilling program and in part to the Greenbank acquisition completed at the end of the third quarter of 2007. During the course of 2008 the Company has been successful at increasing heavy oil production in our Plains core area and natural gas and NGL production in our West Central core area, particularly at Saxon and Elmworth. The field netback for the first three quarters of 2008 almost doubled levels achieved in 2007 primarily due to strong commodity prices. The rapid decline of commodity prices in the fourth quarter of 2008 caused the field netback to fall below 2007 levels. Royalties reflected increases in revenues but remained fairly constant at about a 21 percent average rate. Operating costs pressures were experienced, particularly for trucking, fuel, and well servicing costs for heavy oil, and were higher on a per boe basis. G&A expenses are generally higher in the fourth quarters of any particular year due to costs associated with year-end reporting. In 2008 G&A expenses were higher than in 2007 due to increased activity levels but lower on a per boe basis. Funds from operations (on an absolute and per share basis) improved with higher production and stronger field netbacks (for the first three quarters of 2008). Net income (on an absolute and per share basis) improved in the first half of 2008 over 2007 levels based on higher funds from operations. In the last half of 2008 the Company reported net losses as a result of a $5.7 million write down of goodwill in the third quarter due to equity market conditions and higher depletion expenses.

Net capital expenditures (excluding acquisitions and dispositions) essentially doubled in 2008 over 2007 levels due to increased drilling activity, land acquisitions and seismic operations in both our core areas. Negative working capital also increased in 2008 over the previous quarter as capital spending exceeded funds from operations in all quarters of 2008 except the second quarter due to spring break-up conditions.

Reserves

Rock's reserves have been independently evaluated by GLJ Petroleum Consultants Ltd. (GLJ) at year-end 2008. This is the fifth year that GLJ has evaluated the Company's reserves. The reserves as at December 31, 2008 and 2007 have been evaluated in accordance with *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101)*. The following tables provide a reconciliation of the Company's reserves between year-end 2008 and year-end 2007 on a gross basis (before deducting royalties and without including any royalty interest) (gross interest).

Rock's gross interest reserves at year-end 2008 are 5.8 million boe of proved reserves and 10.2 million boe of proved plus probable reserves. The growth in gross interest reserves resulted from oil and natural gas operations (net of revisions) which added 1.8 million boe of proved reserves and 2.1 million boe of proved plus probable reserves. Proved producing reserves have increased to 46 percent of proved plus probable reserves on a gross interest basis at year-end 2008 from 38 percent at year-end 2007 as a significant amount of capital was spent developing proved reserves and proving up probable reserves, particularly in the West Central core area. The breakdown of reserves on a commodity basis has changed slightly on a proved plus probable basis from 2007 to 2008 with heavy oil now comprising 46 percent of reserves (up from 40percent in 2007) and natural gas comprising 45 percent of reserves (down from 50 percent in 2007). During 2008 the Company sold 0.05 million of proved and 0.07 million of proved plus probable gross interest reserves.

RESERVES RECONCILIATION

The following table is a reconciliation of Rock's gross interest reserves at December 31, 2008 using GLJ's forecast pricing and cost estimates as at December 31, 2008.

Reconciliation of Company Gross Interest Reserves by Principal Product Type (Forecast Prices and Costs)

	Light and Medium Oil		NGL		Heavy Oil		Natural Gas		Total Oil Equivalent	
Factors	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mmcf)	Proved Plus Probable (mmcf)	Proved (mboe)	Proved Plus Probable (mboe)
December 31, 2007	383	572	207	360	2,275	3,764	14,717	27,677	5,318	9,309
Additions[1]	0	0	48	67	1,000	1,741	2,487	3,589	1,462	2,406
Technical revisions[2]	(29)	(115)	227	230	(185)	(346)	2,068	(8)	359	(231)
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	(0)	(0)	(2)	(2)	0	0	(309)	(418)	(53)	(72)
Production	(71)	(71)	(88)	(88)	(486)	(486)	(3,667)	(3,667)	(1,258)	(1,258)
December 31, 2008	284	386	392	567	2,603	4,673	15,295	27,173	5,828	10,154

[1]Additions include discoveries, extensions, infill drilling and improved recovery.
[2]Technical revisions include technical revisions and economic factors.
Note: Figures may not add due to rounding; mbbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe.

RESERVES AND NET PRESENT VALUE (FORECAST PRICES AND COSTS)

The following tables summarize Rock's remaining gross interest reserves volumes along with the value of future net revenue utilizing GLJ's forecast pricing and cost estimates as at December 31, 2008.

Reserves

Reserves Category	Light and Medium Oil (mbbl)	NGL (mbbl)	Heavy Oil (mbbl)	Natural Gas (mmcf)	Total Oil Equivalent (mboe)
Proved					
Proved producing	263	335	1,963	12,779	4,692
Proved non-producing	20	12	156	1,170	383
Proved undeveloped	0	44	485	1,345	753
Total proved	283	392	2,603	15,295	5,828
Probable additional	103	175	2,070	11,878	4,327
Total proved plus probable	386	567	4,673	27,173	10,154

Note: Figures may not add due to rounding; mbbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe..

Net Present Value of Future Net Revenue

	Before Income Taxes					After Income Taxes				
($000)	Discounted at (% per year)					Discounted at (% per year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Proved producing	135,106	114,195	99,586	88,764	80,395	129,769	110,505	96,923	86,779	78,876
Proved non-producing	10,106	7,522	5,965	4,909	4,141	7,702	5,692	4,523	3,744	3,183
Proved undeveloped	13,657	10,361	8,031	6,326	5,043	10,175	7,504	5,643	4,299	3,300
Total proved	158,870	132,077	113,582	100,000	89,579	147,646	123,701	107,089	94,822	85,538
Probable additional	116,782	83,892	63,884	50,497	40,955	87,107	61,954	46,686	36,501	29,089
Total proved plus probable	275,652	215,969	177,466	150,496	130,534	234,753	185,655	153,775	131,323	114,627

Note: Figures may not add due to rounding.

PRICING ASSUMPTIONS

The following benchmark prices, inflation rates and exchange rates were used by GLJ for the forecast prices and costs evaluation.

Summary of Pricing and Cost Rate Assumptions at December 31, 2008 – Forecast Prices and Costs

	Oil				NGL				Natural Gas		
Year	WTI Cushing (US$/bbl)	Edmonton Reference Price ($/bbl)	Cromer Medium 29° API ($/bbl)	Hardisty Heavy 12° API ($/bbl)	Edmonton Propane ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Pentane ($/bbl)	Ethane ($/bbl)	AECO-C ($/mcf)	US$/Cdn$ Exchange Rate	Cost Inflation Rate (%/year)
2009	57.50	68.61	59.00	43.10	43.22	52.14	69.98	25.55	7.58	0.825	2
2010	68.00	78.94	68.68	49.76	49.73	61.57	80.52	26.80	7.94	0.850	2
2011	74.00	83.54	73.52	54.35	52.63	65.16	85.21	28.19	8.34	0.875	2
2012	85.00	90.02	80.01	59.23	57.28	70.92	92.74	29.43	8.70	0.925	2
2013	92.01	95.91	84.40	62.54	60.42	74.81	97.82	30.27	8.95	0.950	2
2014	93.85	97.84	86.10	63.82	61.64	76.32	99.80	30.94	9.14	0.950	2
2015	95.73	99.82	87.84	65.13	62.89	77.86	101.81	31.62	9.34	0.950	2
2016	97.64	101.83	89.61	66.46	64.15	79.43	103.87	32.31	9.54	0.950	2
2017	99.59	103.89	91.42	67.83	65.45	81.03	105.97	33.02	9.75	0.950	2
2018	101.59	105.99	93.27	69.22	66.77	82.67	108.10	33.74	9.95	0.950	2
2019+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.950	2

FINDING, DEVELOPMENT AND ACQUISITION COSTS

The following table summarizes Rock's finding, development and acquisition costs for the years ended December 31, 2008, 2007 and 2006, including future development costs.

	12 months ended Dec. 31, 2008	12 months ended Dec. 31, 2007	12 months ended Dec. 31, 2006	3 Year Cumulative Total
Oil and Natural Gas Operations:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	**$50,939**	$24,163	$32,907	$108,009
Change in future capital costs *($000)*	**(2,948)**	3,501	2,939	3,492
Total capital *($000)*	**$47,991**	$27,664	$35,846	$111,501
Reserve additions[2] *(mboe)*	**1,462**	949	2,181	4,592
Proved finding and development costs *($/boe)*	**$32.82**	$29.15	$16.44	$24.28
Proved plus probable finding and development costs				
Capital expenditures[1] *($000)*	**$50,939**	$24,163	$32,907	$108,009
Change in future capital costs *($000)*	**3,106**	3,930	7,986	15,022
Total capital *($000)*	**$54,045**	$28,093	$40,893	$123,031
Reserve additions[2] *(mboe)*	**2,406**	1,506	3,624	7,536
Proved plus probable finding and development costs *($/boe)*	**$22.46**	$18.66	$11.28	$16.33
Acquisitions/Dispositions:				
Proved finding and development costs – acquisitions (dispositions)				
Capital expenditures[1] *($000)*	**($1,190)**	$28,524	($30,878)	($3,544)
Change in future capital costs *($000)*	**(17)**	4,136	(2,400)	1,719
Total capital *($000)*	**($1,207)**	$32,660	($33,278)	($1,825)
Reserve additions *(mboe)*	**(53)**	971	(1,042)	(125)
Proved finding and development costs *($/boe)*	**$22.59**	$33.64	$31.94	$14.65

Proved plus probable finding and development costs – acquisitions (dispositions)				
Capital expenditures(1) *($000)*	**($1,190)**	$28,524	($30,878)	($3,544)
Change in future capital costs *($000)*	**(17)**	11,417	(2,400)	9,000
Total capital *($000)*	**($1,207)**	$39,941	($33,278)	$5,456
Reserve additions *(mboe)*	**(72)**	1,898	(1,406)	419
Proved plus probable finding and development costs *($/boe)*	**$16.69**	$21.05	$23.67	$13.01
Total Activities:				
Proved finding and development costs				
Capital expenditures(1) *($000)*	**$49,750**	$52,687	$2,029	$104,465
Change in future capital costs *($000)*	**(2,965)**	7,637	539	5,211
Total capital *($000)*	**$46,785**	$60,324	$2,568	$109,676
Reserve additions(3) *(mboe)*	**1,768**	1,643	1,279	4,690
Total proved finding and development costs *($/boe)*	**$26.46**	$36.72	$2.01	$23.39
Proved plus probable finding and development costs				
Capital expenditures(1) *($000)*	**$49,750**	$52,687	$2,029	$104,465
Change in future capital costs *($000)*	**3,089**	15,347	5,586	24,022
Total capital *($000)*	**$52,839**	$68,034	$7,615	$128,487
Reserve additions(3) *(mboe)*	**2,103**	2,786	2,153	7,042
Total proved plus probable finding and development costs *($/boe)*	**$25.13**	$24.42	$3.54	$18.24

(1) Capital expenditures include capitalized G&A which has been allocated between oil and natural gas operations and acquisitions, and exclude purchases of equipment still held in inventory and administrative capital expenditures.

(2) Reserve additions exclude revisions.

(3) Reserve additions include revisions.

(4) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Finding, development and acquisition ("FD&A") costs are broken down according to oil and natural gas operations, acquisitions and dispositions, and total activities. Oil and natural gas operations include all capital activities in which the Company participated, including operations on the acquired properties after their respective closing dates, but exclude reserve revisions. FD&A costs on the acquired properties are based on the reserve evaluation as at each respective year end less new reserves from operations post closing and were increased by the amount of production from the closing date to December 31 of the respective year to provide an estimate of the reserves purchased. FD&A costs on the disposed properties are based on the reserve evaluation as at December 31, of the year prior to the closing date and were decreased by the amount of production to the closing date. FD&A costs for total activities include operations, acquisitions, dispositions and reserve revisions.

Finding and development costs on operations increased in 2008 compared to 2007 and 2006 as Rock spent more capital in the higher cost West Central core area versus the relatively less expensive Plains core area and increased land expenditures over prior years. Capital spending in the West Central core area includes $14 million for infrastructure spending at Saxon and Musreau/Kakwa. Reserve bookings increased at Saxon based on well performance however, Musreau/Kakwa wells have not performed as well as expected. New reserve bookings at Elmworth have been lower than expected but there is little production history with these wells and we do expect some upward revisions in the future. FD&A costs for the West Central core area have been higher than expected in part due to the high infrastructure component and lower initial reserve bookings at Elmworth based on early results. In the Plains core area remediation efforts to solve the gas migration issue at our Edam heavy oil property were slowed by the industry approval process. As a result only one of the three affected wells was on production for a significant amount of time in 2008. A second well was placed on production late in 2008 and a third well should be on production in mid 2009. Production from the first remediated well has been more encouraging lately and Management still believes more reserves will ultimately be recoverable at Edam. In addition Rock started to experience higher water cuts in some wells at our Upgrader heavy oil property and a negative reserve revision has been booked as a result. Longer term well performance will be required to determine ultimate recovery. Of the heavy oil wells drilled in 2008, 15 (15.0 net) have reserves assigned as expected, however 3 (3.0 net) wells experienced production issues within months after completion have no reserves assigned to them. FD&A costs for the Plains core area are generally in line with our expectations. Overall, FD&A costs for 2008 are high. On a three year basis the FD&A costs are more reflective of the progress made in growing the Company and generate recycle ratios (FD&A divided by operating netback) of 1.8:1 for operations and 1.6:1 overall.

LAND HOLDINGS

The following table summarizes Rock's land holdings as at December 31, 2008 and 2007:

(acres)		Dec. 31, 2008	Dec. 31, 2007	Change
Developed	– Gross	**81,091**	87,882	(8)%
	– Net	**30,739**	32,406	(5)%
Undeveloped	– Gross	**135,573**	135,069	0%
	– Net	**80,574**	61,718	31%
Total	– Gross	**216,664**	222,951	(3)%
	– Net	**111,313**	94,123	18%

NET ASSET VALUE

The following table summarizes Rock's net asset value and net asset value per share as at December 31, 2008 and December 31, 2007:

($000 except number of shares and net asset value per share)	December 31, 2008	December 31, 2007	Change
Proved plus probable reserves(1) (2)	**177,466**	152,420	20%
Undeveloped land(3)	**15,425**	13,380	15%
Working capital including debt	**(38,622)**	(29,094)	33%
Net asset value	**154,269**	136,706	16%
Year-end shares outstanding *(000)*	**25,900**	25,878	0%
Net asset value per share	**$5.96**	$5.28	16%
Option proceeds	**5,390**	7,893	(32)%
Net asset value	**159,659**	144,599	14%
Fully diluted shares outstanding *(000)*	**27,644**	28,185	(2)%
Net asset value per share (fully diluted)	**$5.78**	$5.13	16%

(1) Proved plus probable reserves value is based on the net present value of future net revenue from gross reserves using GLJ Petroleum Consultants Ltd.'s January 2008 and 2007 forecast pricing and costs estimates and using a discount rate at 10 percent. Net present value of future net revenue does not represent fair market value.

(2) Reserve values are based on the new Alberta royalty regime for year-end 2008 and the existing Alberta royalty regime for year-end 2007. Note the range of reserve values for 2007 under a high and low royalty assumption case for the new Alberta royalty regime was $144,747 to $152,420 as disclosed in the 2007 Annual Report.

(3) Undeveloped land value is based on the actual cost of land purchased at land sales; land acquired from ELM/Optimum/Qwest in the second quarter of 2005 has been valued at $100 per acre and land acquired through the Greenbank acquisition in the third quarter of 2007 has been valued at $200 per acre.

CONTRACTUAL OBLIGATIONS

In the course of its business, the Company enters into various contractual obligations including the following:

- royalty agreements;
- processing agreements;
- right-of-way agreements; and
- lease obligations for office premises.

Obligations with a fixed term are as follows:

	2009	2010	2011	2012	2013
Office premise leases	$ 828	$ 828	$ 828	$ 552	$ nil
Processing agreements	360	288	238	159	nil
Demand bank loan[1]	$34,175	$-	$-	$-	$-

[1] *The demand bank loan is currently under its annual review and is expected to remain in place.*

OUTSTANDING SHARE DATA

At December 31, 2008 and to date, Rock had 25,889,843 common shares outstanding. At December 31, 2008 the Company had 1,744,204 stock options outstanding with an average exercise price of $3.09 per share. As of the date hereof Rock has 1,688,871 options outstanding.

OFF-BALANCE-SHEET ARRANGEMENTS

Rock does not have any special-purpose entities nor is it party to any arrangement that would be excluded from the balance sheet.

RELATED-PARTY TRANSACTIONS

The Company has not entered into any related-party transactions during the reporting period.

CHANGE IN ACCOUNTING POLICIES

As of January 1, 2008 the Company adopted new policies to implement the pronouncements from the Canadian Institute of Chartered Accountants ("CICA") in respect of capital disclosures and financial instruments - presentation and disclosures. The new standard for capital disclosures requires disclosure on objectives, policies and processes for managing capital. The new standard for financial instruments places increased emphasis and disclosure on the nature and extent of risks arising from financial instruments and how they are managed. The application of these policies did not result in changes to amounts reported in the consolidated financial statements for the period ended December 31, 2008.

NEW ACCOUNTING PRONOUNCEMENTS

Goodwill and Intangible Assets

The CICA in February 2008 issued CICA Handbook section 3064, Goodwill and Intangible Assets, and amended section 1000, Financial Statement Concepts, clarifying the criteria for recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets.

Rock will adopt this section effective January 1, 2009.

International Financial Reporting Standards

In February 2008 the CICA confirmed the implementation of International Financial Reporting Standards ("IFRS") as part of Canadian GAAP. The adoption of IFRS in Canada will result in significant changes to current Canadian GAAP and to financial reporting practices followed by Rock. IFRS accounting standards are to be implemented for years beginning after December 31, 2010. Rock will be required to adopt the standard for the year beginning January 1, 2011.

Rock has participated in an industry task force which has identified issues, helped understand the new accounting policies and the choices that can be made and provided guidance regarding the adoption of IFRS for the oil and natural gas industry. In order to transition to IFRS the Company will have to adopt new accounting policies, procedures and reporting standards. As part of this process Rock will have to transition from the full cost method of accounting, which the Company currently follows, to a method acceptable under IFRS. At a minimum IFRS will require the Company to identify new units of account and cash generating units at a more finite level than under full cost accounting and will also require asset impairment testing at the new unit levels. Setting new IFRS accounting policies and the identification of cash generating units will begin in the second quarter of 2009 but not likely completed until the fourth quarter of 2009. It is likely Rock will need to put in place a new accounting system in order to more effectively handle IFRS accounting procedures. Rock will begin to investigate new systems in the second quarter of 2009 with the intent of having a new system in place and operating by January 2010. Currently IFRS is proposing an amendment that, if successful, would allow Canadian companies using the full cost method of accounting for exploration and development activities to utilize their independent reserve report to allocate certain property, plant and equipment costs to newly defined units of account at the time of transition to IFRS. The proposed amendment would significantly reduce the amount of work required to transition the Company to IFRS. The Company intends to have an opening balance sheet that is IFRS compliant for January 1, 2010 at which point both IFRS and Canadian GAAP compliant financial statements will be maintained in order to facilitate full IFRS compliant reporting effective January 1, 2011. Rock will have in-house staff attend training courses specific to IFRS adoption and policies. Rock may engage external consultants to help with the transition and adoption of IFRS.

Business Combinations

In January 2009, the CICA issued new standards for Business Combinations. This standard is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This standard replaces, Business Combination and harmonizes the Canadian standards with IFRS. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a significant impact on the way the Company accounts for future business combinations.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Company's significant accounting policies is contained in note 2 to the audited consolidated financial statements. These accounting policies are subject to estimates and key judgements about future events, many of which are beyond Rock's control. The following is a discussion of the accounting estimates that are critical to the financial statements.

Oil and Natural Gas Accounting – Reserves Recognition – Rock retained independent petroleum engineering consultants GLJ Petroleum Consultants Ltd. (GLJ) to evaluate its oil and natural gas reserves, prepare an evaluation report, and report to the Company's Reserves Committee. The process of estimating oil and natural gas reserves is subjective and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data. These estimates will change over time as additional data from ongoing development and production activities becomes available and as economic conditions affecting oil and natural gas prices and costs change. Reserves can be classified as proved, probable or possible with decreasing levels of certainty to the likelihood that the reserves will be ultimately produced.

Oil and Natural Gas Accounting – Full Cost Accounting – Under the full cost method of accounting for exploration and development activities, all costs associated with these activities are capitalized. The aggregate net capitalized costs and estimated future abandonment costs, less estimated salvage values, are amortized using the unit-of-production method based on estimated proved oil and natural gas reserves, resulting in a depletion expense. The depletion expense is most affected by the estimate of proved reserves and the cost of unproved properties. Unproved costs are reviewed quarterly to determine if proved reserves have been established, at which point the associated costs are included in the depletion calculation. Changes to any of these estimates may affect Rock's earnings.

Under the full cost method of accounting, the Company's investment in oil and natural gas assets is evaluated at least annually to consider whether the investment is recoverable and the carrying amount does not exceed the value of the properties, a process known as the "ceiling test". The carrying value of oil and natural gas properties and production equipment is compared to the sum of undiscounted cash flows expected to result from Rock's proved reserves. If the carrying value is not fully recoverable, the amount of impairment is measured by comparing the carrying value of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves using a risk-free interest rate. Any excess carrying value above the net present value of the future cash flows is recorded as a permanent impairment. Reserve, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the ceiling test. Revisions of these estimates could result in a write-down of the carrying amount of oil and natural gas properties.

Asset Retirement Obligations – The Company recognizes the estimated fair value of an asset retirement obligation (ARO) in the period in which it is incurred as a liability, and records a corresponding increase in the carrying value of the related asset. The future asset retirement obligation is an estimate based on the Company's ownership interest in wells and facilities and reflects estimated costs to complete the abandonment and reclamation as well as the estimated timing of the costs to be incurred in future periods. Estimates of the costs associated with abandonment and reclamation activities require judgement concerning the method, timing and extent of future retirement activities. The capitalized amount is depleted on a unit-of-production method over the life of the proved reserves. The liability amount is increased each reporting period due to the passage of time and this accretion amount is charged to earnings in the period. Actual costs incurred on settlement of the ARO are charged against the ARO. Judgements affecting current and annual expense are subject to future revisions based on changes in technology, abandonment timing, costs, discount rates and the regulatory environment.

Stock-based Compensation – Stock options issued to employees and directors under the Company's stock option plan are accounted for using the fair value method of accounting for stock-based compensation. The fair value of the option is recognized as stock-based compensation expense and contributed surplus over the vesting period of the option. Stock-based compensation expense is determined on the date of an option grant using the Black-Scholes option pricing model. The Black-Scholes pricing model requires the estimation of several variables including estimated volatility of Rock's stock price over the life of the option, estimated option forfeitures, estimated life of the option, estimated risk-free rate and estimated dividend rate. A change to these estimates would alter the valuation of the option and would result in a different related stock-based compensation expense.

BUSINESS RISKS

Rock is exposed to a number of business risks, some of which are beyond its control, as are all companies in the oil and gas exploration and production industry. These risks can be categorized as operational, financial and regulatory.

Operational risks include generating, finding and developing, and acquiring oil and natural gas reserves on an economical basis (including acquiring land rights or gaining access to land rights); reservoir production performance; marketing; production; hiring and retaining employees; and accessing contract services on a cost-effective basis. Rock attempts to mitigate these risks by employing highly qualified staff and operating in areas where employees have expertise. In addition the Company outsources certain activities to be able to lever industry expertise, without having the burden of hiring full-time staff given the current scope of operations. Typically the Company has outsourced the marketing and certain engineering and land functions. Rock is attempting to acquire existing oil and natural gas operations; however Rock will be competing against many other companies for such operations, many of which will have greater access to resources. As a small company, gaining access to contract services may be difficult given the competitive nature of the industry, but Rock will attempt to mitigate this risk by utilizing existing relationships.

Financial risks include commodity prices, the US/Canadian dollar exchange rate and interest rates, all of which are largely beyond the Company's control. Currently Rock has not used any financial instruments to mitigate these risks. The Company would consider using these financial instruments depending on the operating environment. The Company also will require access to capital. Currently Rock has a debt facility in place and intends to use its debt capacity in the future in conjunction with capital expenditures including acquisitions. It intends to use prudent levels of debt to fund capital programs based on the expected operating environment. It also intends to access equity markets to fund opportunities; however, the ability to access these markets will be determined by many factors, many of which will be beyond the control of the Company.

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Company may, in part, be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid. In the current economic climate, including the recent deterioration in commodity prices, the Company's ability to access both credit and equity markets may be compromised or prohibited as many credit lenders and equity investors are restricting funds available to companies like Rock and as a result, Rock may have to alter its future spending plans.

Rock is subject to various regulatory risks, principally environmental in nature. The Company has put in place a corporate safety program and a site-specific emergency response program to help manage these risks. The Company hires third-party consultants to help develop and manage these programs and help Rock comply with current environmental legislation. Increased public and political concern regarding climate change issues will likely result in increased regulation regarding emissions standards. Given that the Company produces hydrocarbons, such regulation could cause Rock to alter the way it operates and also result in additional costs and taxes associated with climate change regulation which could have a material effect on the Company.

ENVIRONMENTAL RISK AND REGULATION

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 federal, provincial and local laws and regulations. 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. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 emission levels. The Federal government has introduced legislation aimed at reducing greenhouse gas emissions using a "intensity based" approach, the specifics of which have yet to be determined. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. There has been much public debate with respect to Canada's ability to meet these targets and the Federal government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company.

In Alberta, the reduction emission guidelines outlined the Climate Change and Emissions Management Amendment Act (the "Act") came into effect July 1, 2007. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12 percent. Industries have three options to choose from in order to meet the reduction requirements outlined in the Act, and these are: (a) by making improvement to operations that result in reductions; (b) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emissions; or (c) by contributing to the

Climate Change and Emissions Management Fund. Pursuant to the Act, March 31, 2008 was the deadline for industries to choose one of these options or a combination thereof. On April 26, 2007, the Federal government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products.

On January 24, 2008, the Alberta government announced its plan to reduce projected emissions in the province by 50% by 2050. This will result in real reductions of 14 percent below 2005 levels. The Alberta government stated it would form a government-industry council to determine a go-forward plan for implementing technologies, which will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations (carbon capture). In addition, the plan calls for energy conservation by individuals and for increased investment in clean energy technologies and incentives for expanding the use of renewable and alternative energy sources such as bioenergy, wind, solar, hydrogen, and geothermal. Initiatives under this theme will account for 18 percent of Alberta's reductions.

On January 31, 2008, the Government of Canada and the Province of Alberta released the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

On March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" which provides some additional guidance with respect to the Government of Canada's plan to reduce greenhouse gas emissions by 20 percent by 2020 and by 60 percent to 70 percent by 2050. The updated action plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and natural gas, and refining industries. The updated action plan is intended to force industry to reduce greenhouse gas emissions and to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. The updated action plan provides for: (i) mandatory reductions of 18 percent from the 2006 baseline starting in 2010 and by an addition 2 percent in subsequent years for existing facilities; (ii) new facilities built between 2004 and 2011 will have mandatory emissions standards based upon clean fuel standards (gas) with a 2 percent reduction below the third year's intensity levels; and (iii) oil sands plants built in 2012 and later which use heavier hydrocarbons and upgraders and in situ production will have mandatory standards in 2018 based on carbon capture and storage or other green technologies intensity. For the upstream oil and natural gas industry, the updated action plan also provides for a company threshold of 10,000 boe per day and facility threshold of 3,000 tonnes of C02.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Company and its operations and financial condition.

Management's Report

To the Shareholders of Rock Energy Inc.:

The consolidated financial statements of Rock Energy Inc. were prepared by management in accordance with appropriately selected generally accepted accounting principles in Canada. Management has used estimates and careful judgement, particularly in those circumstances where transactions affecting current periods are dependent on information not known until a future period. The financial and operational information contained in this annual report is consistent with that reported in the financial statements.

Management is responsible for the integrity of the financial and operational information contained in this report. The Company has designed and maintains internal controls to provide reasonable assurance that assets are properly safeguarded and that the financial records are well maintained and provide relevant, timely and reliable information to management. The consolidated financial statements have been prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized in the notes to the consolidated financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

Allen J. Bey
President and Chief Executive Officer
March 12, 2009

Peter D. Scott
Vice President, Finance and Chief Financial Officer
March 12, 2009

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Rock Energy Inc. as at December 31, 2008 and 2007 and the consolidated statements of income, comprehensive income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 12, 2009

Consolidated Balance Sheets
(000s of dollars)

As at	December 31, 2008	December 31, 2007
Assets		
Current assets		
Accounts receivable	**$ 11,896**	$ 8,473
Prepaid expenses	**908**	1,383
	12,804	9,856
Property, plant and equipment *(note 6)*	**137,706**	114,891
Goodwill *(note 6)*	**-**	5,748
	$ 150,510	$ 130,495
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 17,251**	$ 11,523
Bank debt *(note 8)*	**34,175**	27,405
	51,426	38,928
Future tax liability *(note 12)*	**5,565**	1,533
Asset retirement obligation *(note 9)*	**4,497**	3,840
Shareholders' equity		
Share capital *(note 10)*	**81,600**	81,600
Contributed surplus *(note 11)*	**3,458**	2,521
Retained earnings	**3,964**	2,073
	89,022	86,194
Commitments *(note 13)*		
	$ 150,510	$ 130,495

See accompanying notes to consolidated financial statements.

Approved by the Board:

James K. Wilson
Director

Allen J. Bey
Director

Consolidated Statements of Income, Comprehensive Income and Retained Earnings

(000s of dollars, except per share amounts)

Years ended	December 31, 2008	December 31, 2007
Revenues:		
Oil and natural gas	$ 80,138	$ 36,042
Royalties	(17,094)	(7,035)
Other income	138	79
	63,182	29,086
Expenses:		
General and administrative	3,236	2,739
Operating	17,361	9,925
Interest	1,565	1,157
Stock-based compensation *(note 11)*	1,158	931
Goodwill impairment *(note 6)*	5,748	-
Depletion, depreciation, and accretion	28,109	14,143
	57,177	28,895
Income before taxes	6,005	191
Taxes		
Provincial capital taxes *(note 12)*	179	76
Future income taxes (reduction) *(note 12)*	3,935	(446)
Net income and comprehensive income for the year	1,891	561
Retained earnings, beginning of year	2,073	1,512
Retained earnings, end of year	$ 3,964	$ 2,073
Diluted and basic net income per share *(note 10)*	$ 0.07	$ 0.03

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

(000s of dollars)

Years ended	December 31, 2008	December 31, 2007
Cash provided by (used in):		
Operating:		
Net income for the year	**$ 1,891**	$ 561
Asset retirement expenditures	**(94)**	-
Add: Non-cash items:		
Depletion, depreciation, and accretion	**28,109**	14,143
Goodwill impairment	**5,748**	-
Stock-based compensation	**1,158**	931
Future income taxes (reduction)	**3,935**	(446)
	40,747	15,189
Changes in non-cash working capital	**843**	(1,035)
	41,590	14,154
Financing:		
Issuance of common shares	**81**	12,456
Bank debt	**6,770**	10,903
Repurchase of stock options	**(205)**	(51)
	6,646	23,308
Investing:		
Property, plant and equipment	**(51,414)**	(25,575)
Acquisition of property, plant and equipment *(note 5)*	**-**	(12,644)
Disposition of property, plant and equipment	**1,243**	-
Changes in non-cash working capital	**1,935**	757
	(48,236)	(37,462)
Change in cash	**-**	-
Cash beginning of year	**-**	-
Cash end of year	**$ -**	$ -
Interest and taxes paid and received:		
Interest paid	**$ 1,565**	$ 1,190
Interest received	**-**	34
Taxes paid	**92**	142

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended December 31, 2008 and 2007

1. Nature of Operations

Rock Energy Inc. (the "Company" or "Rock") is actively engaged in the exploration, production and development of oil and natural gas in Western Canada.

2. Significant Accounting Policies

The consolidated financial statements of Rock are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles (GAAP).

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(A) CONSOLIDATION

These consolidated financial statements include the accounts of Rock Energy Inc., and its wholly owned subsidiaries Rock Energy Ltd. and Rock Energy Production Partnership. All inter-company transactions and balances have been eliminated upon consolidation.

(B) CASH

Cash and cash equivalents are comprised of cash and short-term investments with an original maturity date of three months or less.

(C) JOINT OPERATIONS

A substantial portion of the Company's oil and natural gas exploration and development activities is conducted jointly with others and, accordingly, these consolidated financial statements reflect only the Company's proportionate interest in such activities.

(D) PROPERTY, PLANT AND EQUIPMENT

Capitalized costs: The Company follows the full cost method of accounting for its oil and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges directly related to exploration and development activities. Proceeds from the sale of oil and natural gas properties are applied against capital costs, with no gain or loss recognized, unless such a sale would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion, depreciation and amortization: The capitalized costs are depleted and depreciated using the unit-of-production method based on proved petroleum and natural gas reserves before royalties, as determined by independent consulting engineers. Oil and natural gas liquids reserves and production are converted into equivalent units of natural gas based on relative energy content. Office furniture and equipment are recorded at cost and depreciated on a declining balance basis using a rate of 20 percent. The cost of acquiring and evaluating unproved properties is initially excluded from the depletion calculation. These properties are assessed periodically for impairment. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the costs subject to depletion.

Ceiling test: Rock calculates its ceiling test by comparing the carrying amount of oil and natural gas properties and production equipment to the sum of undiscounted cash flows from proved reserves. If the carrying amount is not fully recoverable, the amount of impairment is measured by comparing the carrying amount of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves, using a risk-free interest rate and expected future prices, and the lower of cost, less impairment, and market value of unproved properties. Any excess carrying amount above the net present value of the future cash flows is recorded as a permanent impairment.

Asset retirement obligations: The Company records the fair value of an asset retirement obligation (ARO) as a liability in the period in which it incurs a legal obligation to restore an oil and natural gas property, typically when a well is drilled or other equipment is put in place. The associated asset retirement costs are capitalized as part of the carrying amount of the related asset and depleted on a unit-of-production method over the life of the proved reserves. Subsequent to initial measurement of the obligations, the obligations are adjusted at the end of each reporting period to reflect the passage of time and changes in estimated future cash flows underlying the obligation. Actual costs incurred on settlement of the ARO are charged against the ARO to the extent incurred, with any remainder recorded to earnings as a gain or loss.

(E) INCOME TAXES

Income taxes are calculated using the asset and liability method of tax accounting. Temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets and liabilities. Future income tax assets and liabilities are calculated using tax rates anticipated to apply in the periods when the temporary differences are expected to reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(F) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Future tax liabilities and share capital are adjusted by the estimated cost of the renounced tax deduction when the expenses are renounced.

(G) STOCK-BASED COMPENSATION

The Company grants options to purchase common shares to employees and directors under its stock option plan. Awards are accounted for using the fair value of accounting for stock-based compensation. Under the fair value method, an estimate of the value of the option is determined at the time of grant using the Black-Scholes option pricing model. The fair value of the option is recognized as an expense and contributed surplus over the vested life of the option. Upon the exercise of stock options the consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(H) REVENUE RECOGNITION

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates.

(I) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property, plant and equipment, the provision for asset retirement obligations, the amounts used for ceiling test calculations and fair value of identifiable assets for goodwill impairment are based on estimates of reserves and future costs. The Company's reserve estimates are reviewed annually by an independent engineering firm. The amounts disclosed relating to fair values of stock options issued are based on estimates of future volatility of the Company's share price, expected lives of options, and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

(J) PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Diluted per share amounts are calculated based on the treasury stock method whereby the weighted average number of shares is adjusted for the dilutive effect of options. The treasury stock method assumes that any proceeds received upon the exercise of stock options would be used to purchase common shares at the estimated average market price of the common shares during the period. Anti dilutive instruments are not included in the calculation.

3. Accounting Policies Changes

(A) FINANCIAL INSTRUMENTS

On January 1, 2008 the Company adopted the new standards relating to "Financial Instruments – Disclosures" and "Financial Instruments – Presentation", which replaced the previous standard "Financial Instruments – Disclosure and Presentation". The new disclosure standard outlines the disclosure requirements for financial instruments and non-financial derivatives. The guidance prescribes an increased importance on risk disclosures associated with recognized and unrecognized financial instruments and how such risks are managed. Specifically, it requires disclosure of the significance of financial instruments for a company's financial position. In addition, the guidance outlines revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments.The new presentation standard requirements are relatively unchanged from the previous presentation requirements.

(B) CAPITAL DISCLOSURES

On January 1, 2008 the Company adopted the new standards for Capital Disclosures requiring disclosures regarding the Company's objectives, policies and processes for managing capital. These disclosures include a description of what the Company manages as capital, the nature of externally imposed capital requirements, how the requirements are incorporated into the Company's management of capital, whether the requirements have been complied with, or consequences of non-compliance and an explanation of how the Company is meeting its objectives for managing capital. In addition, quantitative data about capital and whether the Company has complied with all capital requirements are also required (see note 12).

4. Pending Accounting Changes

(A) GOODWILL

As of January 1, 2009 the Company will be required to adopt new standards for Goodwill and Intangible Assets, which defines the criteria for the recognition of intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The Company does not expect the adoption of this standard will have any impact on the financial statements.

(B) INTERNATIONAL REPORTING STANDARDS

In 2008, the CICA Accounting Standards Board confirmed the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The eventual changeover to IFRS represents changes due to new accounting standards. The Company continues to monitor and assess the impact of the convergence of Canadian GAAP and IFRS but has not at this time made any determination on the impact on the Company's financial statements.

(C) BUSINESS COMBINATIONS

In January 2009, the CICA issued new standards for Business Combinations. This standard is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This standard replaces, Business Combination and harmonizes the Canadian standards with IFRS. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a significant impact on the way the Company accounts for future business combinations.

5. Acquisition of Greenbank Energy Ltd.

On September 28, 2007 the Company purchased a private company by way of a plan of arrangement for cash and shares of the Company. The acquisition has been accounted for using the purchase method and the results of operations for the transaction are included in the financial statements beginning in the fourth quarter of 2007.

The purchase price equation is as follows:

($000)	
Property, plant and equipment	$ 28,127
Bank debt	(5,537)
Working capital deficiency	(330)
Asset retirement obligation	(761)
Future income tax asset	2,963
	$ 24,462
Consideration provided:	
Cash from private placement	$ 12,144
Common shares (3,143,167 issued)	11,818
Transaction costs	500
	$ 24,462

6. Property, Plant and Equipment

($000)	December 31, 2008	December 31, 2007
Petroleum and natural gas properties	**$ 200,994**	$ 150,408
Other assets	**1,432**	1,354
	202,426	151,762
Accumulated depletion and depreciation	**(64,720)**	(36,871)
	$ 137,706	$ 114,891

At December 31, 2008, the depletable base for the petroleum and natural gas properties included $11,704 (December 31, 2007 - $14,404) of future capital costs and excluded $15,425 (December 31, 2007 – $13,380) of unproved property costs.

During the year ended December 31, 2008, $1,592 (year ended December 31, 2007 – $2,004) of administrative costs relating to exploration and development activities were capitalized as part of property, plant and equipment.

At December 31, 2008, the Company applied the ceiling test calculation to its petroleum and natural gas properties using expected future market prices. These expected future market prices were forecast by the Company's independent reserve evaluators and then adjusted for commodity price differentials specific to the Company's production. The following table exhibits the benchmark prices used in the ceiling test:

	Oil WTI (Cushing, Oklahoma) (US$/bbl)	Oil Edmonton par (40 API) (CDN$/bbl)	Natural Gas AECO-C Spot Price (CDN$/mmbtu)	Heavy Oil at Hardisty (12° API) (CDN$/bbl)	Currency Exchange Rate (US$/CDN$)
2009	57.50	68.61	7.58	43.10	0.825
2010	68.00	78.94	7.94	49.76	0.850
2011	74.00	83.54	8.34	54.35	0.875
2012	85.00	90.92	8.70	59.23	0.925
2013	92.01	95.91	8.95	62.54	0.950
2014	93.85	97.84	9.14	63.82	0.950
2015	95.73	99.82	9.34	65.13	0.950
2016	97.64	101.83	9.54	66.46	0.950
2017	99.59	103.89	9.75	67.83	0.950
2018	101.59	105.99	9.95	69.22	0.950
Thereafter (escalation)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	0.950

Goodwill of $5,748 was written off due to the application of a market based impairment test as at September 30, 2008. The Company does not have any impairment related to its property, plant and equipment.

7. Risk Management and Financial Instruments

Commodity Price Risk:

Due to the volatile nature of commodity prices the Company is potentially exposed to adverse consequences if commodity prices decline. However, if commodity prices are hedged potential upside gains may also be forfeited. As of December 31, 2008 the Company did not have any commodity price contracts. A $1.00 per barrel change in the price the Company would have received for its oil and natural gas liquids production is estimated to result in a $352 change in net income for 2008. A $0.25 per mcf change in the price the Company would have received for its natural gas production is estimated to result in a $500 change in net income for 2008.

Foreign Currency Exchange Risk:

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced in U.S. dollar denominated prices. As of December 31, 2008 the Company did not have any foreign currency exchange contracts in place. A $0.01 change in the Canadian dollar/U.S. dollar exchange rate is estimated to result in a $535 change in net income for 2008.

Credit Risk:

Substantially all of the accounts receivable are with customers, joint interest partners and oil and natural gas marketers and are subject to normal industry credit risks. Receivables from customers and joint interest partners are generally collected within one to three months. The Company attempts to mitigate this risk by entering into transactions with long-standing and reputable organizations and by obtaining partner approval of significant capital expenditures and payment of cash advances wherever possible. Further risk exists with joint interest partners as disagreements occasionally arise and may increase the potential for non-collection. Receivables related to oil and natural gas marketers are normally collected on the 25th day of the month following production. To mitigate the risk on these receivables the Company will predominately establish relationships with large marketers who have strong credit ratings and solid reputations. Historically, the Company has not experienced any issues in collecting from its oil and natural gas marketers. As at December 31, 2008 the Company's receivables consisted of $7,966 (December 31, 2007 - $4,132) from joint interest partners, $3,397 (December 31, 2007 - $3,228) from oil and gas marketers, and $533 (December 31, 2007 - $1,113) of other trade receivables.

Fair Value of Financial Instruments:

The Company's exposure under its financial instruments is limited to financial assets and liabilities, all of which are included in these financial statements. The fair values of the financial assets and liabilities included in the balance sheet approximate their carrying amounts.

Interest Rate Risk:

The Company is exposed to interest rate risk to the extent that bank debt is at a floating or short term rate of interest. The Company does not have any financial or interest rate contracts in place as of December 31, 2008. A 1 percent change to the floating or short term interest rates is estimated to result in a $218 change in net income for 2008.

8. Bank Debt

At December 31, 2008 the Company had a demand operating facility with a Canadian chartered bank subject to the bank's valuation of the Company's oil and natural gas properties. The limit under the facility at December 31, 2008 was $51 million. The facility is secured by a first ranking floating charge on all real property of the Company, its subsidiary and partnership and a general security agreement. The facility bears interest at the bank's prime rate or at prevailing bankers' acceptance rate plus an applicable bank fee, which varies depending on the Company's debt-to-funds from operations ratio. The facility also bears a standby charge for un-drawn amounts. The next review is to be completed before April 30, 2009

9. Asset Retirement Obligation

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations at December 31, 2008 was approximately $7,716 (December 31, 2007 – $6,474), which will be incurred between 2009 and 2020. A credit-adjusted risk-free rate of 8 percent and an annual inflation rate of 1.5 percent were used to calculate the future asset retirement obligation.

	December 31, 2008	December 31, 2007
Balance, beginning of year	$ 3,840	$ 2,094
Liabilities incurred/acquired	549	1,592
Dispositions	(58)	-
Accretion	260	154
Actual retirement costs	(94)	-
Balance, end of year	$ 4,497	$ 3,840

10. Share Capital

(A) AUTHORIZED:

Unlimited number of voting common shares, without stated par value.

300,000 preference shares, without stated par value.

(B) COMMON SHARES ISSUED:

Common Shares of Rock	Number	Amount ($000)
Issued and outstanding as at December 31, 2006	19,637,321	$ 57,326
Issued for flow-through shares *(i)*	10,007	42
Issued in private placement	2,998,623	12,144
Issued for property acquisitions	3,143,167	11,818
Issued for flow-through shares *(ii)*	88,524	270
Issued and outstanding as at December 31, 2007	25,877,642	$ 81,600
Future tax effect of flow-through share renouncements *(ii)*	-	(98)
Issued on exercise of stock options	13,334	59
Issued for flow-through shares *(i)*	8,867	39
Issued and outstanding as at December 31, 2008	25,899,843	$ 81,600

(i) In accordance with the Company's stock option plan, some options were exercised in exchange for flow-through shares of the Company.

(ii) The Company issued flow-through shares to new management appointees. By February 29, 2008 all of the renouncements were made.

(C) STOCK OPTIONS

The Company has a stock option plan under which it may grant options to directors, officers and employees for the purchase of up to 10 percent of the issued and outstanding common shares of the Company. Options are granted at the discretion of the Board of Directors. The exercise price, vesting period and expiration period are also fixed at the time of grant at the discretion of the Board of Directors. The majority of options vest yearly in one-third tranches beginning on the first anniversary of the grant date and expire one year after vesting. Options expiring are usually replaced with another grant that vests in two years and expires in three years. At the Company's discretion the options can be exercised for cash. The following table summarizes the status of the Company's stock option plan as at December 31, 2007 and December 31, 2006 and changes during the year ended on those dates:

	December 31, 2008		December 31, 2007	
	Options	**Weighted-Average Exercise Price ($)**	Options	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**2,307,822**	**$3.42**	1,767,277	$ 4.19
Granted	**444,532**	**$2.92**	1,258,366	$ 2.79
Exercised	**(198,240)[(ii)]**	**$3.26**	(82,485)[(i)]	$3.49
Forfeited	**(423,328)**	**$3.28**	(286,890	$4.23
Expired	**(386,582)**	**$4.61**	(348,446)	$ 4.36
Outstanding, end of year	**1,744,204**	**$3.09**	2,307,822	$ 3.42

(i) Options were put back to the Company for in-the-money gain.

(ii) 184,906 options were put back to the Company for in-the-money gain.

Options outstanding and exercisable under the stock option plan are summarized below as at December 31, 2008:

	Outstanding Options			Exercisable Options	
	Number of Options	Weighted-Average Exercise Price	Weighted-Average Years to Expiry	Number of Options	Weighted-Average Exercise Price ($)
$1.37 - $2.04	112,000	$ 1.62	2.88	-	$ -
$2.25 - $3. 32	1,278,207	$ 2.82	1.85	322,389	$ 2.72
$3.41 - $5.11	353,997	$ 4.52	1.13	202,331	$ 4.86
	1,744,204	$ 3.09	1.79	524,720	$ 3.54

(D) PER SHARE AMOUNTS

The weighted average number of common shares outstanding during the year ended December 31, 2008 of 25,885,309 (year ended December 31, 2007 – 21,238,886) was used to calculate per share amounts. To calculate diluted common shares outstanding, the treasury method was used. Under this method, in-the-money options are assumed exercised and the proceeds used to repurchase shares at the year-end date of December 31, 2008. As at December 31, 2008 an additional 37,714 (December 31, 2007 – nil) common shares were used to calculate diluted earnings per share.

11. Stock-Based Compensation

Options granted to employees and non-employees after March 31, 2003 are accounted for using the fair value method. The fair value of common share options granted for the year ended December 31, 2008 was estimated to be $616 (year ended December 31, 2007 – $1,434) as at the grant date using the Black-Scholes option pricing model and the following assumptions:

Risk-free interest rate	4.00% - 5.25%
Expected life	Three-year average
Expected volatility	65% - 85%
Expected dividend yield	0%

Contributed surplus:

	December 31, 2008	December 31, 2007
Balance, beginning of year	$ 2,521	$ 1,641
Stock-based compensation expense	1,158	931
Net benefit on options exercised[1]	(221)	(51)
Balance, end of year	$ 3,458	$ 2,521

(1) The benefit of options exercised is recorded as a reduction of contributed surplus and an increase to share capital.

12. Income Taxes

The provision for income taxes varies from the amount that would be computed by applying the expected tax rate to income before taxes. The expected tax rate used was 29.8 percent (December 31, 2007 – 32.40 percent). The principal reasons for differences between such "expected" income tax expense and the amount actually recorded are as follows:

	December 31, 2008	December 31, 2007
Income before taxes	$ 6,005	$ 191
Statutory income tax rate	29.8%	32.4%
Expected income taxes	$ 1,789	$ 62
Add (deduct):		
Stock-based compensation	345	302
Change in enacted rates	38	(365)
Other	72	(375)
Goodwill impairment	1,714	-
Change in valuation allowance	(23)	(70)
Future income taxes (reduction)	$ 3,935	$ (446)
Capital tax	179	76
Provision for (recovery of) income taxes	$ 4,114	$ (370)

Future income tax assets or liabilities recognized on the consolidated balance sheets are comprised of temporary differences. The after-tax effect of these temporary differences is summarized as follows:

	December 31, 2008	December 31, 2007
Loss carry-forwards	$ 3,485	$ 4,587
Property, plant and equipment	(60)	(2,070)
Deferral of partnership earnings	(9,810)	(4,808)
Share issuance costs	231	331
Asset retirement obligation	1,214	1,075
Calculated future income tax liability	(4,940)	(885)
Valuation allowance	(625)	(648)
Future income taxes (liability)	$ (5,565)	$ (1,533)

At December 31, 2008, Rock and its subsidiaries had tax pools totalling $148.6 million prior to the allocation of deferred partnership income and $114.8 million after the allocation of deferred partnership income. The non-capital losses prior to the allocation of deferred partnership income expire as follows:

2014	$ 1,320
2015	1,031
2026	6,695
2027	1,893
	$ 10,939

13. Commitments

Obligations with a fixed term are as follows:

	2009	2010	2011	2012	2013
Lease of office premises	$ 828	$ 828	$ 828	$ 552	$ -
Processing arrangements	$ 360	$ 288	$ 238	$ 159	$ -

14. Capital Disclosures

In order to continue the Company's future exploration and development program, the Company must maintain a strong capital base. A strong capital base results in increased market confidence, an essential factor in maintaining existing shareholders and in attracting new investors. The Company's commitment is to establish and maintain a strong capital base to enable the Company to access the equity and debt markets when deemed advisable. In order to maintain a strong capital base, the Company continually monitors the risk reward profile of its exploration and development projects and the economic indicators in the market including commodity prices, interest rates and foreign exchange rates. It then determines increases or decreases to its capital budget.

The Company considers shareholders' equity, bank debt and working capital as components of its capital base. The Company can access or increase capital through the issuance of shares, through bank borrowings, that are based on reserves, and by building cash reserves by reducing its capital expenditure program. The components of the Company's capital base at December 31, 2008 and 2007 is presented below.

	December 31, 2008	December 31, 2007
Shareholders' equity	$ 89,022	$ 86,194
Bank debt	34,175	27,405
Working capital deficiency (excluding bank debt)	4,447	1,667

The Company monitors its capital structure based primarily on its debt-to-annualized funds flow ratio. Debt includes bank debt plus or minus working capital. Annualized funds flow is calculated as funds flow from operations before changes in non-cash working capital from the Company's most recent quarter multiplied by four. The Company's strategy is to maintain this ratio at less than 1.5:1. This ratio may increase on a cyclical basis depending on the timing and nature of the Company's activities and commodity price fluctuations. To facilitate the management and control of this ratio, the Company prepares an annual operating and capital expenditure budget. The budget is updated when critical factors change. These factors include economic factors such as the state of equity markets, changes to commodity prices, interest rates and foreign exchange rates and non economic factors such as the Company's drilling results and its production profile. The Company's Board of Directors approves the budget and material changes thereto.

At December 31, 2008, the Company's debt to funds flow ratio was 1.75:1 compared to 0.6:1 at the end of the second and third quarters and 1.3:1 at the end of the first quarter of 2008. The ratio is generally higher at the end of the first and third quarters which tend to be high capital expenditure quarters (the first quarter due to winter access only operations and the third quarter due to post spring break-up activities). The second quarter is typically a low capital expenditure quarter due to spring break-up curtailing operations. The increased activity levels usually result in the Company carrying a higher debt load at the end of the first and third quarters, depending on actual commodity prices. The production additions from activities usually occur in the quarter following the operation and are expected to contribute to increased funds flow, subject to prevailing commodity prices. The ratio has increased at the end of the fourth quarter and is above the Company's target primarily due to a significant decline in commodity prices. Based on the Company's current projections the Company plans on paying down debt but this ratio is expected to be above the target level for all of 2009 but is not expected to breach any debt covenants.

The Company's share capital is not subject to external restrictions but the Company does have financial covenants in regards to its operating bank facility. The facility requires that the Company maintain a working capital ratio of not less than 1:1. The calculation allows for the unused portion of the credit facility to be added to current assets and deduction of the current portion of bank debt from the current liabilities. The Company would be considered in breach of its agreement if the working capital ratio was not maintained, unless consented to by the lender, in which case the bank may demand repayment of the loan.

Advisory

This press release contains forward-looking statements that involve known and unknown risks, uncertainties, assumptions and other factors, some of which are beyond Rock's control, that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Rock believes that the expectations reflected in those forward-looking statements are reasonable at the time made 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 press release should not be unduly relied upon. These statements speak only as of the date of such information, as the case may be, and may be superseded by subsequent events. Rock does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable law.

This press release contains references to barrels of oil equivalent (boe), boes maybe misleading, particularly if used in isolation. A boe conversion of 6 mcf to 1 barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

For further information please visit our website at www.rockenergy.ca or contact:

Allen Bey
President & CEO
(403) 218-4380
or
Peter D. Scott
Vice President, Finance & CFO
(403) 218-4380

File No. 82-34785

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Washington, DC 106

Rock Energy Files Annual Information Form

March 13, 2009, Calgary Alberta: Rock Energy Inc. (TSX:RE) "Rock" filed its Annual Information Form today which includes Rock's reserves data and other oil and gas information for the year ended December 31, 2008 as mandated by National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators. Copies of Rock's Annual Information Form may be obtained on www.sedar.com or by contacting Rock.

Rock is a Calgary, Alberta, Canada based crude oil and natural gas exploration, development and production company.

For further information please visit our website at www.rockenergy.ca or contact:

Allen Bey
President & CEO
(403) 218-4380
or
Peter D. Scott
Vice President, Finance & CFO
(403) 218-4380

SEC Mail Processing Section

MAR 17 2009

Washington, DC 106

FORM 52-109F1
CERTIFICATION OF ANNUAL FILINGS
FULL CERTIFICATE

I, Allen J. Bey, President and Chief Executive Officer of Rock Energy Inc., certify the following

1. *Review:* I have reviewed the AIF, if any, annual financial statements and annual MD&A, including, for greater certainty, all documents and information that are incorporated by reference in the AIF (together, the "annual filings") of Rock Energy Inc. (the "issuer") for the financial year ended December 31, 2008.

2. *No misrepresentations:* Based on my knowledge, having exercised reasonable diligence, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, for the period covered by the annual filings.

3. *Fair presentation:* Based on my knowledge, having exercised reasonable diligence, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date of and for the periods presented in the annual filings.

4. *Responsibility:* The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, for the issuer.

5. *Design:* Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer's other certifying officer(s) and I have, as at the financial year end

   (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that

      (i) material information relating to the issuer is made known to us by others, particularly during the period in which the annual filings are being prepared; and

      (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and

   (b) designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP.

5.1 *Control framework:* The control framework the issuer's other certifying officer(s) and I used to design the issuer's ICFR is the Committee on Sponsoring Organizations (COSO) framework.

5.2 *N/A*

5.3 *N/A*

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6. ***Evaluation:*** The issuer's other certifying officer(s) and I have

   (a) evaluated, or caused to be evaluated under our supervision, the effectiveness of the issuer's DC&P at the financial year end and the issuer has disclosed in its annual MD&A our conclusions about the effectiveness of DC&P at the financial year end based on that evaluation; and

   (b) evaluated, or caused to be evaluated under our supervision, the effectiveness of the issuer's ICFR at the financial year end and the issuer has disclosed in its annual MD&A

      (i) our conclusions about the effectiveness of ICFR at the financial year end based on such evaluation; and

      (ii) *N/A*

7. ***Reporting changes in ICFR*:** The issuer has disclosed in its annual MD&A any change in the issuer's ICFR that occurred during the period beginning on October 1, 2008 and ended on December 31, 2008 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

8. ***Reporting to the issuer's auditors and board of directors or audit committee*:** The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of ICFR, to the issuer's auditors, and the board of directors or the audit committee of the board of directors any fraud that involves management or other employees who have a significant role in the issuer's ICFR.

Date: March 13, 2009

Signed "Allen J. Bey"

Allen J. Bey
President & Chief Executive Officer

File No. 82-34785

FORM 52-109F1
CERTIFICATION OF ANNUAL FILINGS
FULL CERTIFICATE

I, Peter D. Scott, Vice President, Finance and Chief Financial Officer of Rock Energy Inc., certify the following

1. ***Review:*** I have reviewed the AIF, if any, annual financial statements and annual MD&A, including, for greater certainty, all documents and information that are incorporated by reference in the AIF (together, the "annual filings") of Rock Energy Inc. (the "issuer") for the financial year ended December 31, 2008.

2. ***No misrepresentations:*** Based on my knowledge, having exercised reasonable diligence, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, for the period covered by the annual filings.

3. ***Fair presentation:*** Based on my knowledge, having exercised reasonable diligence, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date of and for the periods presented in the annual filings.

4. ***Responsibility:*** The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, for the issuer.

5. ***Design:*** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer's other certifying officer(s) and I have, as at the financial year end

   (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that

      (i) material information relating to the issuer is made known to us by others, particularly during the period in which the annual filings are being prepared; and

      (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and

   (b) designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP.

5.1 ***Control framework:*** The control framework the issuer's other certifying officer(s) and I used to design the issuer's ICFR is the Committee on Sponsoring Organizations (COSO) framework.

5.2 *N/A*

5.3 *N/A*

6. ***Evaluation:*** The issuer's other certifying officer(s) and I have

   (a) evaluated, or caused to be evaluated under our supervision, the effectiveness of the issuer's DC&P at the financial year end and the issuer has disclosed in its annual MD&A our conclusions about the effectiveness of DC&P at the financial year end based on that evaluation; and

   (b) evaluated, or caused to be evaluated under our supervision, the effectiveness of the issuer's ICFR at the financial year end and the issuer has disclosed in its annual MD&A

      (i) our conclusions about the effectiveness of ICFR at the financial year end based on such evaluation; and

      (ii) *N/A*

7. ***Reporting changes in ICFR***: The issuer has disclosed in its annual MD&A any change in the issuer's ICFR that occurred during the period beginning on October 1, 2008 and ended on December 31, 2008 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

8. ***Reporting to the issuer's auditors and board of directors or audit committee***: The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of ICFR, to the issuer's auditors, and the board of directors or the audit committee of the board of directors any fraud that involves management or other employees who have a significant role in the issuer's ICFR.

Date: March 13, 2009

Signed "Peter D. Scott"

Peter D. Scott
Vice President, Finance & Chief Financial Officer

File No. 82-34785

rockenergy

Management's Report

To the Shareholders of Rock Energy Inc.:

The consolidated financial statements of Rock Energy Inc. were prepared by management in accordance with appropriately selected generally accepted accounting principles in Canada. Management has used estimates and careful judgement, particularly in those circumstances where transactions affecting current periods are dependent on information not known until a future period. The financial and operational information contained in this annual report is consistent with that reported in the financial statements.

Management is responsible for the integrity of the financial and operational information contained in this report. The Company has designed and maintains internal controls to provide reasonable assurance that assets are properly safeguarded and that the financial records are well maintained and provide relevant, timely and reliable information to management. The consolidated financial statements have been prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized in the notes to the consolidated financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

Allen J. Bey
President and Chief Executive Officer
March 12, 2009

Peter D. Scott
Vice President, Finance and Chief Financial Officer
March 12, 2009

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Rock Energy Inc. as at December 31, 2008 and 2007 and the consolidated statements of income, comprehensive income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 12, 2009

Consolidated Balance Sheets
(000s of dollars)

As at	December 31, 2008	December 31, 2007
Assets		
Current assets		
Accounts receivable	**$ 11,896**	$ 8,473
Prepaid expenses	**908**	1,383
	12,804	9,856
Property, plant and equipment *(note 6)*	**137,706**	114,891
Goodwill *(note 6)*	**-**	5,748
	$ 150,510	$ 130,495
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 17,251**	$ 11,523
Bank debt *(note 8)*	**34,175**	27,405
	51,426	38,928
Future tax liability *(note 12)*	**5,565**	1,533
Asset retirement obligation *(note 9)*	**4,497**	3,840
Shareholders' equity		
Share capital *(note 10)*	**81,600**	81,600
Contributed surplus *(note 11)*	**3,458**	2,521
Retained earnings	**3,964**	2,073
	89,022	86,194
Commitments *(note 13)*		
	$ 150,510	$ 130,495

See accompanying notes to consolidated financial statements.

Approved by the Board:

James K. Wilson
Director

Allen J. Bey
Director

Consolidated Statements of Income, Comprehensive Income and Retained Earnings

(000s of dollars, except per share amounts)

Years ended	December 31, 2008	December 31, 2007
Revenues:		
Oil and natural gas	**$ 80,138**	$ 36,042
Royalties	**(17,094)**	(7,035)
Other income	**138**	79
	63,182	29,086
Expenses:		
General and administrative	**3,236**	2,739
Operating	**17,361**	9,925
Interest	**1,565**	1,157
Stock-based compensation *(note 11)*	**1,158**	931
Goodwill impairment *(note 6)*	**5,748**	-
Depletion, depreciation, and accretion	**28,109**	14,143
	57,177	28,895
Income before taxes	**6,005**	191
Taxes		
Provincial capital taxes *(note 12)*	**179**	76
Future income taxes (reduction) *(note 12)*	**3,935**	(446)
Net income and comprehensive income for the year	**1,891**	561
Retained earnings, beginning of year	**2,073**	1,512
Retained earnings, end of year	**$ 3,964**	$ 2,073
Diluted and basic net income per share *(note 10)*	**$ 0.07**	$ 0.03

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows
(000s of dollars)

Years ended	December 31, 2008	December 31, 2007
Cash provided by (used in):		
Operating:		
Net income for the year	**$ 1,891**	$ 561
Asset retirement expenditures	**(94)**	-
Add: Non-cash items:		
Depletion, depreciation, and accretion	**28,109**	14,143
Goodwill impairment	**5,748**	-
Stock-based compensation	**1,158**	931
Future income taxes (reduction)	**3,935**	(446)
	40,747	15,189
Changes in non-cash working capital	**843**	(1,035)
	41,590	14,154
Financing:		
Issuance of common shares	**81**	12,456
Bank debt	**6,770**	10,903
Repurchase of stock options	**(205)**	(51)
	6,646	23,308
Investing:		
Property, plant and equipment	**(51,414)**	(25,575)
Acquisition of property, plant and equipment *(note 5)*	**-**	(12,644)
Disposition of property, plant and equipment	**1,243**	-
Changes in non-cash working capital	**1,935**	757
	(48,236)	(37,462)
Change in cash	**-**	-
Cash beginning of year	**-**	-
Cash end of year	**$ -**	$ -
Interest and taxes paid and received:		
Interest paid	**$ 1,565**	$ 1,190
Interest received	**-**	34
Taxes paid	**92**	142

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended December 31, 2008 and 2007

1. Nature of Operations

Rock Energy Inc. (the "Company" or "Rock") is actively engaged in the exploration, production and development of oil and natural gas in Western Canada.

2. Significant Accounting Policies

The consolidated financial statements of Rock are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles (GAAP).

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(A) CONSOLIDATION

These consolidated financial statements include the accounts of Rock Energy Inc., and its wholly owned subsidiaries Rock Energy Ltd. and Rock Energy Production Partnership. All inter-company transactions and balances have been eliminated upon consolidation.

(B) CASH

Cash and cash equivalents are comprised of cash and short-term investments with an original maturity date of three months or less.

(C) JOINT OPERATIONS

A substantial portion of the Company's oil and natural gas exploration and development activities is conducted jointly with others and, accordingly, these consolidated financial statements reflect only the Company's proportionate interest in such activities.

(D) PROPERTY, PLANT AND EQUIPMENT

Capitalized costs: The Company follows the full cost method of accounting for its oil and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges directly related to exploration and development activities. Proceeds from the sale of oil and natural gas properties are applied against capital costs, with no gain or loss recognized, unless such a sale would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion, depreciation and amortization: The capitalized costs are depleted and depreciated using the unit-of-production method based on proved petroleum and natural gas reserves before royalties, as determined by independent consulting engineers. Oil and natural gas liquids reserves and production are converted into equivalent units of natural gas based on relative energy content. Office furniture and equipment are recorded at cost and depreciated on a declining balance basis using a rate of 20 percent. The cost of acquiring and evaluating unproved properties is initially excluded from the depletion calculation. These properties are assessed periodically for impairment. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the costs subject to depletion.

Ceiling test: Rock calculates its ceiling test by comparing the carrying amount of oil and natural gas properties and production equipment to the sum of undiscounted cash flows from proved reserves. If the carrying amount is not fully recoverable, the amount of impairment is measured by comparing the carrying amount of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves, using a risk-free interest rate and expected future prices, and the lower of cost, less impairment, and market value of unproved properties. Any excess carrying amount above the net present value of the future cash flows is recorded as a permanent impairment.

Asset retirement obligations: The Company records the fair value of an asset retirement obligation (ARO) as a liability in the period in which it incurs a legal obligation to restore an oil and natural gas property, typically when a well is drilled or other equipment is put in place. The associated asset retirement costs are capitalized as part of the carrying amount of the related asset and depleted on a unit-of-production method over the life of the proved reserves. Subsequent to initial measurement of the obligations, the obligations are adjusted at the end of each reporting period to reflect the passage of time and changes in estimated future cash flows underlying the obligation. Actual costs incurred on settlement of the ARO are charged against the ARO to the extent incurred, with any remainder recorded to earnings as a gain or loss.

(E) INCOME TAXES

Income taxes are calculated using the asset and liability method of tax accounting. Temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets and liabilities. Future income tax assets and liabilities are calculated using tax rates anticipated to apply in the periods when the temporary differences are expected to reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(F) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Future tax liabilities and share capital are adjusted by the estimated cost of the renounced tax deduction when the expenses are renounced.

(G) STOCK-BASED COMPENSATION

The Company grants options to purchase common shares to employees and directors under its stock option plan. Awards are accounted for using the fair value of accounting for stock-based compensation. Under the fair value method, an estimate of the value of the option is determined at the time of grant using the Black-Scholes option pricing model. The fair value of the option is recognized as an expense and contributed surplus over the vested life of the option. Upon the exercise of stock options the consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(H) REVENUE RECOGNITION

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates.

(I) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property, plant and equipment, the provision for asset retirement obligations, the amounts used for ceiling test calculations and fair value of identifiable assets for goodwill impairment are based on estimates of reserves and future costs. The Company's reserve estimates are reviewed annually by an independent engineering firm. The amounts disclosed relating to fair values of stock options issued are based on estimates of future volatility of the Company's share price, expected lives of options, and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

(J) PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Diluted per share amounts are calculated based on the treasury stock method whereby the weighted average number of shares is adjusted for the dilutive effect of options. The treasury stock method assumes that any proceeds received upon the exercise of stock options would be used to purchase common shares at the estimated average market price of the common shares during the period. Anti dilutive instruments are not included in the calculation.

3. Accounting Policies Changes

(A) FINANCIAL INSTRUMENTS

On January 1, 2008 the Company adopted the new standards relating to "Financial Instruments – Disclosures" and "Financial Instruments – Presentation", which replaced the previous standard "Financial Instruments – Disclosure and Presentation". The new disclosure standard outlines the disclosure requirements for financial instruments and non-financial derivatives. The guidance prescribes an increased importance on risk disclosures associated with recognized and unrecognized financial instruments and how such risks are managed. Specifically, it requires disclosure of the significance of financial instruments for a company's financial position. In addition, the guidance outlines revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments.The new presentation standard requirements are relatively unchanged from the previous presentation requirements.

(B) CAPITAL DISCLOSURES

On January 1, 2008 the Company adopted the new standards for Capital Disclosures requiring disclosures regarding the Company's objectives, policies and processes for managing capital. These disclosures include a description of what the Company manages as capital, the nature of externally imposed capital requirements, how the requirements are incorporated into the Company's management of capital, whether the requirements have been complied with, or consequences of non-compliance and an explanation of how the Company is meeting its objectives for managing capital. In addition, quantitative data about capital and whether the Company has complied with all capital requirements are also required (see note 12).

4. Pending Accounting Changes

(A) GOODWILL

As of January 1, 2009 the Company will be required to adopt new standards for Goodwill and Intangible Assets, which defines the criteria for the recognition of intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The Company does not expect the adoption of this standard will have any impact on the financial statements.

(B) INTERNATIONAL REPORTING STANDARDS

In 2008, the CICA Accounting Standards Board confirmed the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The eventual changeover to IFRS represents changes due to new accounting standards. The Company continues to monitor and assess the impact of the convergence of Canadian GAAP and IFRS but has not at this time made any determination on the impact on the Company's financial statements.

(C) BUSINESS COMBINATIONS

In January 2009, the CICA issued new standards for Business Combinations. This standard is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This standard replaces, Business Combination and harmonizes the Canadian standards with IFRS. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a significant impact on the way the Company accounts for future business combinations.

5. Acquisition of Greenbank Energy Ltd.

On September 28, 2007 the Company purchased a private company by way of a plan of arrangement for cash and shares of the Company. The acquisition has been accounted for using the purchase method and the results of operations for the transaction are included in the financial statements beginning in the fourth quarter of 2007.

The purchase price equation is as follows:

($000)

Property, plant and equipment	$ 28,127
Bank debt	(5,537)
Working capital deficiency	(330)
Asset retirement obligation	(761)
Future income tax asset	2,963
	$ 24,462
Consideration provided:	
Cash from private placement	$ 12,144
Common shares (3,143,167 issued)	11,818
Transaction costs	500
	$ 24,462

6. Property, Plant and Equipment

($000)	December 31, 2008	December 31, 2007
Petroleum and natural gas properties	**$ 200,994**	$ 150,408
Other assets	**1,432**	1,354
	202,426	151,762
Accumulated depletion and depreciation	**(64,720)**	(36,871)
	$ 137,706	$ 114,891

At December 31, 2008, the depletable base for the petroleum and natural gas properties included $11,704 (December 31, 2007 - $14,404) of future capital costs and excluded $15,425 (December 31, 2007 – $13,380) of unproved property costs.

During the year ended December 31, 2008, $1,592 (year ended December 31, 2007 – $2,004) of administrative costs relating to exploration and development activities were capitalized as part of property, plant and equipment.

At December 31, 2008, the Company applied the ceiling test calculation to its petroleum and natural gas properties using expected future market prices. These expected future market prices were forecast by the Company's independent reserve evaluators and then adjusted for commodity price differentials specific to the Company's production. The following table exhibits the benchmark prices used in the ceiling test:

	Oil WTI (Cushing, Oklahoma) (US$/bbl)	Oil Edmonton par (40 API) (CDN$/bbl)	Natural Gas AECO-C Spot Price (CDN$/mmbtu)	Heavy Oil at Hardisty (12° API) (CDN$/bbl)	Currency Exchange Rate (US$/CDN$)
2009	57.50	68.61	7.58	43.10	0.825
2010	68.00	78.94	7.94	49.76	0.850
2011	74.00	83.54	8.34	54.35	0.875
2012	85.00	90.92	8.70	59.23	0.925
2013	92.01	95.91	8.95	62.54	0.950
2014	93.85	97.84	9.14	63.82	0.950
2015	95.73	99.82	9.34	65.13	0.950
2016	97.64	101.83	9.54	66.46	0.950
2017	99.59	103.89	9.75	67.83	0.950
2018	101.59	105.99	9.95	69.22	0.950
Thereafter (escalation)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	0.950

Goodwill of $5,748 was written off due to the application of a market based impairment test as at September 30, 2008. The Company does not have any impairment related to its property, plant and equipment.

7. Risk Management and Financial Instruments

Commodity Price Risk:

Due to the volatile nature of commodity prices the Company is potentially exposed to adverse consequences if commodity prices decline. However, if commodity prices are hedged potential upside gains may also be forfeited. As of December 31, 2008 the Company did not have any commodity price contracts. A $1.00 per barrel change in the price the Company would have received for its oil and natural gas liquids production is estimated to result in a $352 change in net income for 2008. A $0.25 per mcf change in the price the Company would have received for its natural gas production is estimated to result in a $500 change in net income for 2008.

Foreign Currency Exchange Risk:

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced in U.S. dollar denominated prices. As of December 31, 2008 the Company did not have any foreign currency exchange contracts in place. A $0.01 change in the Canadian dollar/U.S. dollar exchange rate is estimated to result in a $535 change in net income for 2008.

Credit Risk:

Substantially all of the accounts receivable are with customers, joint interest partners and oil and natural gas marketers and are subject to normal industry credit risks. Receivables from customers and joint interest partners are generally collected within one to three months. The Company attempts to mitigate this risk by entering into transactions with long-standing and reputable organizations and by obtaining partner approval of significant capital expenditures and payment of cash advances wherever possible. Further risk exists with joint interest partners as disagreements occasionally arise and may increase the potential for non-collection. Receivables related to oil and natural gas marketers are normally collected on the 25th day of the month following production. To mitigate the risk on these receivables the Company will predominately establish relationships with large marketers who have strong credit ratings and solid reputations. Historically, the Company has not experienced any issues in collecting from its oil and natural gas marketers. As at December 31, 2008 the Company's receivables consisted of $7,966 (December 31, 2007 - $4,132) from joint interest partners, $3,397 (December 31, 2007 - $3,228) from oil and gas marketers, and $533 (December 31, 2007 - $1,113) of other trade receivables.

Fair Value of Financial Instruments:

The Company's exposure under its financial instruments is limited to financial assets and liabilities, all of which are included in these financial statements. The fair values of the financial assets and liabilities included in the balance sheet approximate their carrying amounts.

Interest Rate Risk:

The Company is exposed to interest rate risk to the extent that bank debt is at a floating or short term rate of interest. The Company does not have any financial or interest rate contracts in place as of December 31, 2008. A 1 percent change to the floating or short term interest rates is estimated to result in a $218 change in net income for 2008.

8. Bank Debt

At December 31, 2008 the Company had a demand operating facility with a Canadian chartered bank subject to the bank's valuation of the Company's oil and natural gas properties. The limit under the facility at December 31, 2008 was $51 million. The facility is secured by a first ranking floating charge on all real property of the Company, its subsidiary and partnership and a general security agreement. The facility bears interest at the bank's prime rate or at prevailing bankers' acceptance rate plus an applicable bank fee, which varies depending on the Company's debt-to-funds from operations ratio. The facility also bears a standby charge for un-drawn amounts. The next review is to be completed before April 30, 2009

9. Asset Retirement Obligation

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations at December 31, 2008 was approximately $7,716 (December 31, 2007 – $6,474), which will be incurred between 2009 and 2020. A credit-adjusted risk-free rate of 8 percent and an annual inflation rate of 1.5 percent were used to calculate the future asset retirement obligation.

	December 31, 2008	December 31, 2007
Balance, beginning of year	**$ 3,840**	$ 2,094
Liabilities incurred/acquired	**549**	1,592
Dispositions	**(58)**	-
Accretion	**260**	154
Actual retirement costs	**(94)**	-
Balance, end of year	**$ 4,497**	$ 3,840

10. Share Capital

(A) AUTHORIZED:

Unlimited number of voting common shares, without stated par value.
300,000 preference shares, without stated par value.

(B) COMMON SHARES ISSUED:

Common Shares of Rock	Number	Amount ($000)
Issued and outstanding as at December 31, 2006	19,637,321	$ 57,326
Issued for flow-through shares *(i)*	10,007	42
Issued in private placement	2,998,623	12,144
Issued for property acquisitions	3,143,167	11,818
Issued for flow-through shares *(ii)*	88,524	270
Issued and outstanding as at December 31, 2007	25,877,642	$ 81,600
Future tax effect of flow-through share renouncements *(ii)*	-	(98)
Issued on exercise of stock options	13,334	59
Issued for flow-through shares *(i)*	8,867	39
Issued and outstanding as at December 31, 2008	25,899,843	$ 81,600

(i) In accordance with the Company's stock option plan, some options were exercised in exchange for flow-through shares of the Company.

(ii) The Company issued flow-through shares to new management appointees. By February 29, 2008 all of the renouncements were made.

(C) STOCK OPTIONS

The Company has a stock option plan under which it may grant options to directors, officers and employees for the purchase of up to 10 percent of the issued and outstanding common shares of the Company. Options are granted at the discretion of the Board of Directors. The exercise price, vesting period and expiration period are also fixed at the time of grant at the discretion of the Board of Directors. The majority of options vest yearly in one-third tranches beginning on the first anniversary of the grant date and expire one year after vesting. Options expiring are usually replaced with another grant that vests in two years and expires in three years. At the Company's discretion the options can be exercised for cash. The following table summarizes the status of the Company's stock option plan as at December 31, 2007 and December 31, 2006 and changes during the year ended on those dates:

	December 31, 2008		December 31, 2007	
	Options	**Weighted-Average Exercise Price ($)**	Options	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**2,307,822**	**$3.42**	1,767,277	$ 4.19
Granted	**444,532**	**$2.92**	1,258,366	$ 2.79
Exercised	**(198,240)[(ii)]**	**$3.26**	(82,485)[(i)]	$3.49
Forfeited	**(423,328)**	**$3.28**	(286,890	$4.23
Expired	**(386,582)**	**$4.61**	(348,446)	$ 4.36
Outstanding, end of year	**1,744,204**	**$3.09**	2,307,822	$ 3.42

(i) Options were put back to the Company for in-the-money gain.

(ii) 184,906 options were put back to the Company for in-the-money gain.

Options outstanding and exercisable under the stock option plan are summarized below as at December 31, 2008:

	Outstanding Options			Exercisable Options	
	Number of Options	Weighted-Average Exercise Price	Weighted-Average Years to Expiry	Number of Options	Weighted-Average Exercise Price ($)
$1.37 - $2.04	112,000	$ 1.62	2.88	-	$ -
$2.25 - $3. 32	1,278,207	$ 2.82	1.85	322,389	$ 2.72
$3.41 - $5.11	353,997	$ 4.52	1.13	202,331	$ 4.86
	1,744,204	$ 3.09	1.79	524,720	$ 3.54

(D) PER SHARE AMOUNTS

The weighted average number of common shares outstanding during the year ended December 31, 2008 of 25,885,309 (year ended December 31, 2007 – 21,238,886) was used to calculate per share amounts. To calculate diluted common shares outstanding, the treasury method was used. Under this method, in-the-money options are assumed exercised and the proceeds used to repurchase shares at the year-end date of December 31, 2008. As at December 31, 2008 an additional 37,714 (December 31, 2007 – nil) common shares were used to calculate diluted earnings per share.

11. Stock-Based Compensation

Options granted to employees and non-employees after March 31, 2003 are accounted for using the fair value method. The fair value of common share options granted for the year ended December 31, 2008 was estimated to be $616 (year ended December 31, 2007 – $1,434) as at the grant date using the Black-Scholes option pricing model and the following assumptions:

Risk-free interest rate	4.00% - 5.25%
Expected life	Three-year average
Expected volatility	65% - 85%
Expected dividend yield	0%

Contributed surplus:

	December 31, 2008	December 31, 2007
Balance, beginning of year	**$ 2,521**	$ 1,641
Stock-based compensation expense	**1,158**	931
Net benefit on options exercised[1]	**(221)**	(51)
Balance, end of year	**$ 3,458**	$ 2,521

(1) The benefit of options exercised is recorded as a reduction of contributed surplus and an increase to share capital.

12. Income Taxes

The provision for income taxes varies from the amount that would be computed by applying the expected tax rate to income before taxes. The expected tax rate used was 29.8 percent (December 31, 2007 – 32.40 percent). The principal reasons for differences between such "expected" income tax expense and the amount actually recorded are as follows:

	December 31, 2008	December 31, 2007
Income before taxes	**$ 6,005**	$ 191
Statutory income tax rate	**29.8%**	32.4%
Expected income taxes	**$ 1,789**	$ 62
Add (deduct):		
Stock-based compensation	**345**	302
Change in enacted rates	**38**	(365)
Other	**72**	(375)
Goodwill impairment	**1,714**	-
Change in valuation allowance	**(23)**	(70)
Future income taxes (reduction)	**$ 3,935**	$ (446)
Capital tax	**179**	76
Provision for (recovery of) income taxes	**$ 4,114**	$ (370)

Future income tax assets or liabilities recognized on the consolidated balance sheets are comprised of temporary differences. The after-tax effect of these temporary differences is summarized as follows:

	December 31, 2008	December 31, 2007
Loss carry-forwards	**$ 3,485**	$ 4,587
Property, plant and equipment	**(60)**	(2,070)
Deferral of partnership earnings	**(9,810)**	(4,808)
Share issuance costs	**231**	331
Asset retirement obligation	**1,214**	1,075
Calculated future income tax liability	**(4,940)**	(885)
Valuation allowance	**(625)**	(648)
Future income taxes (liability)	**$ (5,565)**	$ (1,533)

At December 31, 2008, Rock and its subsidiaries had tax pools totalling $148.6 million prior to the allocation of deferred partnership income and $114.8 million after the allocation of deferred partnership income. The non-capital losses prior to the allocation of deferred partnership income expire as follows:

2014	**$ 1,320**
2015	**1,031**
2026	**6,695**
2027	**1,893**
	$ 10,939

13. Commitments

Obligations with a fixed term are as follows:

	2009	2010	2011	2012	2013
Lease of office premises	$ 828	$ 828	$ 828	$ 552	$ -
Processing arrangements	$ 360	$ 288	$ 238	$ 159	$ -

14. Capital Disclosures

In order to continue the Company's future exploration and development program, the Company must maintain a strong capital base. A strong capital base results in increased market confidence, an essential factor in maintaining existing shareholders and in attracting new investors. The Company's commitment is to establish and maintain a strong capital base to enable the Company to access the equity and debt markets when deemed advisable. In order to maintain a strong capital base, the Company continually monitors the risk reward profile of its exploration and development projects and the economic indicators in the market including commodity prices, interest rates and foreign exchange rates. It then determines increases or decreases to its capital budget.

The Company considers shareholders' equity, bank debt and working capital as components of its capital base. The Company can access or increase capital through the issuance of shares, through bank borrowings, that are based on reserves, and by building cash reserves by reducing its capital expenditure program. The components of the Company's capital base at December 31, 2008 and 2007 is presented below.

	December 31, 2008	December 31, 2007
Shareholders' equity	**$ 89,022**	$ 86,194
Bank debt	**34,175**	27,405
Working capital deficiency (excluding bank debt)	**4,447**	1,667

The Company monitors its capital structure based primarily on its debt-to-annualized funds flow ratio. Debt includes bank debt plus or minus working capital. Annualized funds flow is calculated as funds flow from operations before changes in non-cash working capital from the Company's most recent quarter multiplied by four. The Company's strategy is to maintain this ratio at less than 1.5:1. This ratio may increase on a cyclical basis depending on the timing and nature of the Company's activities and commodity price fluctuations. To facilitate the management and control of this ratio, the Company prepares an annual operating and capital expenditure budget. The budget is updated when critical factors change. These factors include economic factors such as the state of equity markets, changes to commodity prices, interest rates and foreign exchange rates and non economic factors such as the Company's drilling results and its production profile. The Company's Board of Directors approves the budget and material changes thereto.

At December 31, 2008, the Company's debt to funds flow ratio was 1.75:1 compared to 0.6:1 at the end of the second and third quarters and 1.3:1 at the end of the first quarter of 2008. The ratio is generally higher at the end of the first and third quarters which tend to be high capital expenditure quarters (the first quarter due to winter access only operations and the third quarter due to post spring break-up activities). The second quarter is typically a low capital expenditure quarter due to spring break-up curtailing operations. The increased activity levels usually result in the Company carrying a higher debt load at the end of the first and third quarters, depending on actual commodity prices. The production additions from activities usually occur in the quarter following the operation and are expected to contribute to increased funds flow, subject to prevailing commodity prices. The ratio has increased at the end of the fourth quarter and is above the Company's target primarily due to a significant decline in commodity prices. Based on the Company's current projections the Company plans on paying down debt but this ratio is expected to be above the target level for all of 2009 but is not expected to breach any debt covenants. The ratio is expected to improve primarily when commodity prices improve.

The Company's share capital is not subject to external restrictions but the Company does have financial covenants in regards to its operating bank facility. The facility requires that the Company maintain a working capital ratio of not less than 1:1. The calculation allows for the unused portion of the credit facility to be added to current assets and deduction of the current portion of bank debt from the current liabilities. The Company would be considered in breach of its agreement if the working capital ratio was not maintained, unless consented to by the lender, in which case the bank may demand repayment of the loan.

File No. 82-34785

rockenergy

Management's Discussion and Analysis

ROCK ENERGY INC. ("ROCK" OR THE "COMPANY") is a publicly traded energy company engaged in the exploration for and the development and production of crude oil and natural gas, primarily in Western Canada. Rock's corporate strategy is to grow and develop an oil and natural gas exploration and production company through internal operations and acquisitions.

Rock evaluates its performance based on net income, field netback, funds from operations and finding and development costs. Funds from operations are a measure used by the Company to analyze operations, performance, leverage and liquidity. Field netback is a benchmark used in the oil and natural gas industry to measure the contribution of the oil and natural gas operations following the deduction of royalties, transportation costs and operating expenses. Finding and development costs are another benchmark used in the oil and natural gas industry to measure the capital costs incurred by the Company to find and bring reserves on-stream.

Rock faces competition in the oil and natural gas industry for resources, including technical personnel and third-party services, and capital financing. The Company is addressing these issues through the addition of personnel with the expertise to develop opportunities on existing lands and to control operating and administrative cost structures. Rock also seeks to obtain the best price available based on the quality of its produced commodities.

The following Management's Discussion and Analysis is dated March 12, 2009 and is management's assessment of Rock's historical, financial and operating results, together with future prospects, and should be read in conjunction with the audited consolidated financial statements of Rock for the year ended December 31, 2008.

BASIS OF PRESENTATION

Certain financial measures referred to in this discussion, such as funds from operations and funds from operations per share, are not prescribed by generally accepted accounting principles (GAAP). Funds from operations is a key measure that demonstrates the ability to generate cash to fund expenditures. Funds from operations is calculated by taking the cash provided by operations from the consolidated statement of cash flows and adding back changes in non-cash working capital. Funds from operations per share is calculated using the same methodology for determining net income per share. These non-GAAP financial measures may not be comparable to similar measures presented by other companies. These financial measures are not intended to represent operating profits for the period nor should they be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with GAAP. The reconciliation between funds from operations and cash flow from operations for the three months and years ended December 31, 2008 and 2007 is presented in the table below.

($thousands)	**12 Months Ended 12/31/08**	12 Months Ended 12/31/07	3 Months Ended 12/31/08	3 Months Ended 12/31/07
Funds from operations	**$40,747**	$15,189	$5,516	$4,735
Changes in non-cash working capital	**843**	(1,035)	745	251
Cash flow from operations	**$41,590**	$14,154	$6,261	$4,986

Management uses certain industry benchmarks such as field netback to analyze financial and operating performance. Field netback has been calculated by taking oil and gas revenue less royalties, operating costs and transportation costs. This benchmark does not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other companies. Management considers field netback as an important measure to demonstrate profitability relative to commodity prices.

All barrels of oil equivalent (boe) conversions in this report are derived by converting natural gas to oil at the ratio of six thousand cubic feet (mcf) of natural gas to one barrel (bbl) of oil. Certain financial values are presented on a boe basis and such measurements may not be consistent with those used by other companies. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf to one boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.

Certain statements and information contained in this document, including but not limited to management's assessment of Rock's plans and future operations, production, reserves, revenue, commodity prices, operating and administrative expenditures, future income taxes, wells drilled, acquisitions and dispositions, funds from operations, capital expenditure programs and debt levels, contain forward-looking statements. All statements other than statements of historical fact may be forward-looking statements. These statements, by their nature, are subject to numerous risks and uncertainties, some of which are beyond Rock's control, including the effect of general economic conditions, industry conditions, regulatory and taxation regimes, volatility of commodity prices, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel, any of which may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such forward-looking statements, although considered reasonable by management at the time of preparation, may prove to be incorrect and actual results may differ materially from those anticipated in the statements made and, therefore, should not unduly be relied on. These statements speak only as of the date of this document. Rock does not intend and does not assume any obligation to update these forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law.

All financial amounts are in thousands of Canadian dollars unless otherwise noted.

GUIDANCE AND OUTLOOK

The Company issued guidance on November 13, 2008 for projected 2008 and 2009 results. The table below provides the guidance for 2008 with actual results.

2008 Guidance

	2008 Guidance	Actual	Difference
2008 Production *(boe/d)*			
Annual	3,400-3,600	3,436	0%
Exit (December average)	4,300-4,500	4,055	(8)%
2008 Funds from Operations			
Annual	$43 million	$40.7 million	(5)%
Annual *(per share)*	$1.66	$1.57	(5)%
2008 Capital Budget			
Expenditures	$52 million	$50.2 million	(3)%
Gross wells drilled	34	33	(3)%
Total net debt at year end	$38 million	$38.6 million	2%
Pricing (Fourth Quarter)			
Oil – WTI	US$70.00/bbl	US$58.73/bbl	(16)%
Natural gas – AECO	$7.00/mcf	$6.70/mcf	(4)%
US/Cdn dollar exchange rate	0.85	0.825	(3)%

Production average for the year was within the guidance range however the exit rate was below guidance primarily as the compressor expansion at Elmworth in the West Central core area did not come on-stream until mid first quarter 2009 compared to our forecast start date of mid November 2008 and we elected to leave approximately 100 bbls/day of heavy oil shut-in for maintenance purposes given the low heavy oil price. Funds flow from operations was below guidance due to lower prices and production in the fourth quarter of 2008. Capital expenditures were lower than forecast as 1 (1.0 net) well at Saxon didn't start drilling until the first quarter of 2009. As a result of lower funds from operations, partially offset by lower capital expenditures, debt levels were slightly above guidance levels.

Guidance for 2009 has been updated to reflect results from the winter drilling program, well performance and lower expected commodity prices. The table below updates the Company's previous guidance that was issued November 13, 2008.

	2009 Previous Guidance	2009 Revised Guidance	Change
2009 Production *(boe/d)*			
Annual	4,100-4,300	3,200-3,400	(21)%
Exit	4,400-4,600	3,100-3,300	(29)%
2009 Funds from Operations			
Annual	$33 million	$17.5 million	(47)%
Annual – *(per share)*	$1.28	$0.68	(47)%
2009 Capital Budget			
Expenditures	$37.5 million	$15 million	(60)%
Gross wells drilled	35	12	(66)%
Total net debt at year-end	$42.5 million	$36.1 million	(15)%
Pricing (Annual average)			
Oil – WTI	US$70.00/bbl	US$47.00/bbl	(33)%
Natural gas – AECO	Cdn$7.00/mcf	Cdn$5.00/mcf	(29)%
US/Cdn dollar exchange rate	0.85	0.80	(6)%

The decline in commodity prices has caused Rock to significantly cut back on capital expenditures. If these commodity prices persist the Company anticipates drilling 12 (10.7 net) wells in 2009 of which 2 (1.3 net) wells were drilled in the first quarter of 2009. Furthermore wells that require servicing are likely to be delayed unless a short payout period can be achieved on the expected service expenditures. Rock anticipates acquiring land and seismic (current budget of $1.8 million) in order to develop additional drilling inventory which can be accessed once commodity prices improve. Rock anticipates that Lloyd blend heavy oil prices need to approach $50.00/bbl and natural gas prices need to exceed $7.00/mcf in order to significantly expand our drilling activities. In the current environment Rock anticipates natural production declines and delayed well servicing will cause 2009 production to average approximately 3,300 boe/day with exit rates of approximately 3,200 boe/day. The combined reduction in commodity prices and production is expected to result in funds from operations for 2009 of approximately $17.5 million ($0.68 per basic share). Royalty rates are expected to average 15 percent in this price environment and after taking into account the new initiatives recently announced by the Alberta government (down from 26 percent in the previous forecast), operating costs are expected to average 5 percent higher than previously forecast at $12.85/boe based on recent experience and net G&A expense of $2.60/boe (up from $2.00/boe in our previous guidance due to lower forecast production). Debt to funds from operations ratio is expected to be about 2.1 times on annual basis, falling from a high of 2.9 times in the first quarter down to 1.7 times in the fourth quarter. Management believes in the current commodity price cycle capital expenditures should be less than funds from operations, with capital expenditures directed at preserving the reserve base. We will continue to monitor, debt availability, funds from operations and capital expenditures in order to chart a prudent course of action and stay within our borrowing capacity.

PRODUCTION and PRICES

Production by Product

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Change
Natural gas *(mcf/d)*	**10,048**	4,261	**136%**	11,731	6,372	84%
Light and medium oil *(bbls/d)*	**193**	215	**(10)%**	169	206	(18)%
Heavy oil *(bbls/d)*	**1,329**	1,194	**11%**	1,537	1,323	16%
NGL *(bbls/d)*	**239**	79	**203%**	298	81	268%
Total (boe/d) *(6:1)*	**3,436**	2,198	**56%**	3,959	2,672	48%

Production by Area

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Change
West Central Alberta *(boe/d)*	**1,722**	642	**168%**	2,090	1,041	101%
Plains *(boe/d)*	**1,362**	1,196	**14%**	1,563	1,325	18%
Other *(boe/d)*	**352**	360	**(2)%**	306	306	0%
Total (boe/d) *(6:1)*	**3,436**	2,198	**56%**	3,959	2,672	48%

Production increased 56 percent for the year ended December 31, 2008 over the prior year due to new natural gas and NGL production from Saxon in the West Central core area, production acquired and new drilling at Elmworth, and increased heavy oil production. New production at Saxon (West Central core area) reflects our efforts in the deep basin area over the last several years. Land and seismic was acquired in the summer of 2007 and the first wells were drilled and tied-in during the 2007-08 winter drilling season resulting in new production coming on-stream in May 2008. Rock still has 4 – 6 additional locations in inventory. The Company's Elmworth property in the West Central core area was acquired with the Greenbank acquisition at the end of the third quarter of 2007. Production at the time of acquisition was approximately 500 boe/day (92 percent natural gas) and through drilling this past summer has grown to more than 700 boe/day. Start up of a compressor expansion scheduled for mid November 2008 was delayed until early February 2009 and is expected to add additional production. Heavy oil production increases were driven by drilling which primarily occurred in third quarter of 2008. Of the 18 (18.0 net) cased wells drilled, 14 (14.0 net) are producing at expected rates or better, 1 (1.0 net) is waiting on recompletion and 3 (3.0 net) have declined significantly within months of production and are currently shut-in.

Production increased by 48 percent in the fourth quarter of 2008 from the same period last year and reached 4,000 boe/day during the quarter due to the Company's drilling activity at Saxon and Elmworth in the West Central core area and heavy oil in the Plains core area. Later in the fourth quarter and continuing in the first quarter of 2009 the Company has delayed servicing of some heavy oil wells and delayed the drilling of any additional wells subsequent to the Saxon and Elmworth wells that were drilled in January 2009. As a result current production is approximately 3,700 boe/day. New production from the Elmworth drills plus the start up of additional compression at Elmworth will help offset production declines and delayed servicing.

Product Prices

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Realized Product Prices						
Natural gas *($/mcf)*	**8.72**	6.96	25%	7.27	6.64	9%
Light and medium oil *($/bbl)*	**95.86**	70.69	36%	57.20	81.66	(30)%
Heavy oil *($/bbl)*	**71.58**	41.18	74%	40.17	42.56	(6)%
NGL *($/bbl)*	**74.15**	60.00	24%	45.78	67.81	(32)%
Combined average ($/boe) *(6:1)*	**63.73**	44.93	42%	43.02	45.26	(5)%

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Average Reference Prices						
Natural gas – Henry Hub Daily Spot *(US$/mmbtu)*	**8.88**	6.98	27%	6.47	7.01	(8)%
Natural gas – AECO C Daily Spot *($/mcf)*	**8.16**	6.45	27%	6.70	6.15	9%
Oil – WTI Cushing, Oklahoma *(US$/bbl)*	**99.65**	72.31	38%	58.73	90.68	(35)%
Oil – Edmonton Light *($/bbl)*	**102.16**	76.35	34%	63.21	86.42	(27)%
Heavy oil – Lloydminster blend *($/bbl)*	**82.87**	51.63	61%	48.61	55.49	(12)%
US/Cdn $ exchange rate	**0.943**	0.935	1%	0.825	1.019	(19)%

The first three quarters of 2008 are in contrast to the last quarter of 2008 with respect to commodity price realizations. Rock experienced very strong pricing in the former periods and continual deterioration in prices, particularly for oil based products, in the latter period. The Company realized its lowest prices over the year in December 2008 of $34.60/boe versus the highest realized prices of $89.57/boe in July 2008.

Heavy oil prices were significantly higher for the year ended 2008 compared to 2007 based on the strength of the first three quarters while prices in the fourth quarter of 2008 were 6 percent lower than the same period in 2007. The drop in WTI prices in the fourth quarter were partially offset by narrower price differentials to Edmonton par pricing (36 percent in Q4 2008 versus 51 percent in Q4 2007). WTI prices are currently around US$45/bbl and heavy oil differentials appeared to have narrowed from December 2008 levels resulting in an current estimated heavy oil wellhead price of $35/bbl (compared to $19/bbl for December 2008).

Canadian natural gas prices for the year and fourth quarter of 2008 were higher than 2007. Similar to oil, natural gas prices were higher for the first three quarters of 2008 as higher U.S. prices more than offset the stronger Canadian dollar during this period. However in the fourth quarter of 2008, the weaker Canadian dollar and narrower pricing differential more than offset the decline in US gas prices resulting in a higher Canadian gas price than in the fourth quarter of 2007. Late in the fourth quarter and continuing into 2009, natural gas prices (both in the US and Canada) have continued to decline as the combination of reduced industrial demand due to a poor economy and increased US production from shale gas has more than offset the effect of a colder winter and the lack of liquefied natural gas imports. As a result storage levels compared to last year have gone from a year over year deficit entering the heating season in November 2008 to a surplus currently. Canadian natural gas prices at AECO are currently about $4.25/mcf, approximately 35 percent lower than the $6.60/mcf for December 2008. Rock has not hedged any commodity prices at this time.

REVENUE

The vast majority of the Company's revenue is derived from oil and natural gas operations. Other income is primarily royalty interest revenue.

Oil and Natural Gas Revenue

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Natural gas	**$ 32,052**	$ 10,830	196%	$ 7,845	$ 3,890	102%
Light and medium oil	**6,780**	5,538	22%	889	1,547	(43)%
Heavy oil	**34,813**	17,951	94%	5,681	5,180	10%
NGL	**6,493**	1,724	277%	1,255	507	148%
	80,138	36,042	122%	15,670	11,124	41%
Other revenue	**$ 138**	$ 79	75%	$76	$ 12	533%

Oil and natural gas revenue more than doubled for the year ended December 31, 2008 over 2007 due to higher realized prices and production levels. For the fourth quarter of 2008 oil and natural gas revenue increased by 41 percent from the same period in 2007 as higher production and higher natural gas prices more than offset the decrease in oil prices.

ROYALTIES

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Royalties	**$17,094**	$7,035	143%	$3,366	$2,017	67%
As a percentage of oil and natural gas revenue	**21.3%**	19.5%	9%	21.6%	18.1%	19%
Per boe *(6:1)*	**$13.59**	$8.77	55%	$9.24	$8.21	13%

Royalties increased for the year and quarter ended December 31, 2008 over the prior year periods due to higher production levels and higher prices. Alberta Royalty Tax Credits (ARTC), which was cancelled effective January 1, 2007, impacted both the fourth quarter of 2008 and 2007. The fourth quarter of 2008 included a charge of $72 as a result of an ARTC audit on previously acquired properties and the fourth quarter of 2007 included a $459 benefit as companies with off-calendar (non-December 31) tax year-ends were allowed to benefit from a full calendar year of ARTC. Without the ARTC benefit the royalty rates for 2007 would have been 22.2 percent for the quarter and 20.8 percent for the year.

OPERATING EXPENSES

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Operating expense	**$ 16,456**	$ 9,505	73%	$ 5,207	$ 2,889	80%
Transportation costs	**905**	420	114%	251	130	89%
	17,361	9,925	75%	5,458	3,019	81%
Per boe *(6:1)*	**$13.81**	$12.37	11%	$14.99	$12.28	22%

Operating expenses for the year and quarter ended December 31, 2008 increased over 2007 primarily due to higher production and per unit costs. Heavy oil operations experienced increased cost pressures in 2008 as a result of higher fuel, trucking and service costs compared to the prior year. Fourth quarter 2008 heavy oil operating costs were also negatively impacted by extremely cold weather in December 2008 which lead to higher fuel usage. As a result heavy oil per boe operating costs increased in 2008 to 17.60/boe (18.42/boe for the fourth quarter of 2008) from

12.90/boe in 2007 (13.61/boe for the fourth quarter of 2007). West Central operations tend to have lower operating costs, particulary at Elmworth, which helps lower the corporate average per boe. Transportation costs increased as a result of the properties acquired at the end of third quarter of 2007.

GENERAL and ADMINSTRATIVE (G&A) EXPENSE

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Gross	**$ 4,924**	$ 4,791	3%	$ 1,421	$ 1,593	(11)%
Per boe *(6:1)*	**3.92**	5.97	(34)%	3.90	6.48	(40)%
Capitalized	**1,592**	2,004	(21)%	400	589	(32)%
Per boe *(6:1)*	**1.27**	2.50	(49)%	1.10	2.39	(54)%
Overhead recoveries	**96**	48	100%	30	49	(39)%
Per boe *(6:1)*	**0.08**	0.06	33%	0.08	0.21	(62)%
Net	**3,236**	2,739	18%	991	955	4%
Per boe *(6:1)*	**2.57**	3.41	(25)%	2.72	3.88	(30)%

G&A expense increased on an absolute basis in 2008 over 2007 but declined on a per boe basis. Costs increased due to the higher overall cost environment as well as consulting costs associated with higher activity levels. In the fourth quarter of 2008 the Company recorded $59 of bad debt expense related to prior acquisitions. Rock capitalizes certain G&A expenses based on personnel involved in exploration and development initiatives, including salaries and related overhead costs.

INTEREST EXPENSE

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Interest expense	**$ 1,565**	$ 1,157	35%	$ 331	$ 417	(21)%
Per boe *(6:1)*	**$1.24**	$1.44	(14)%	$0.91	$1.70	(46)%

Interest expense increased for the year ended 2008 over the 2007 period due to higher average bank debt ($31.4 million for 2008 versus $18.5 million for 2007), partially offset by lower interest rates. For the fourth quarter of 2008 lower average interest rates more than offset the increase in average bank debt ($32.6 million for fourth quarter of 2008 versus $26.2 million for the fourth quarter of 2007) resulting in lower interest expense. Bank debt increased as capital expenditures, excluding acquisitions, exceeded funds from operations and were funded through the Company's bank facility.

DEPLETION, DEPRECIATION and ACCRETION (DD&A)

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
D&D expense	**$ 27,849**	$ 13,989	99%	$ 7,734	$ 5,021	54%
Per boe *(6:1)*	**$22.15**	$17.44	27%	$21.24	$20.42	4%
Accretion expense	**$ 260**	$ 154	69%	$ 71	$ 48	48%
Per boe *(6:1)*	**$0.21**	$0.19	11%	$0.19	$0.20	(5)%

Depletion and depreciation expense for the year and quarter ended December 31, 2008 increased over the prior year periods due to higher production and higher cost reserve additions in 2008. The Company spent relatively more capital in the West Central core area (including approximately $14 million of infrastructure costs) which tends to have higher cost reserve additions than the Plains core area.

The Company's asset retirement obligation (ARO) represents the present value of estimated future costs to be incurred to abandon and reclaim the Company's wells and facilities. The discount rate used is 8 percent.

Accretion represents the change in the time value of ARO. The underlying ARO may be increased over a period based on new obligations incurred from drilling wells, constructing facilities or acquiring operations. Similarly, this obligation can also be reduced as a result of abandonment work undertaken and reducing future obligations. During the year ended December 31, 2008 capital programs net of dispositions increased the underlying ARO by $491 (December 31, 2007 – $1,592) and actual expenditures on abandonments were $94 (December 31, 2007 – $nil).

INCOME TAX

The Company pays Saskatchewan resource capital taxes based on its production in the province. Rock does not have current income tax payable and does not expect to pay current income taxes in 2009 as the Company and its subsidiaries had estimated resource and other pools available at December 31, 2008 (after the allocation of deferred partnership income) of approximately $114.7 million as set out below:

CEE	$ 28.2 million
CDE	34.6 million
COGPE	10.5 million
UCC	29.5 million
Loss carry-forwards	10.9 million
Other	1.0 million
Total	$ 114.7 million

FUNDS FROM OPERATIONS and NET INCOME/(LOSS)

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Funds from operations	**$40,747**	$15,189	168%	$5,516	$4,735	16%
Per boe *(6:1)*	**$32.40**	$18.93	71%	$15.15	$19.26	(21)%
Per share:						
Basic	**$1.57**	$ 0.72	118%	$0.21	$ 0.18	17%
Diluted	**$1.57**	$ 0.72	118%	$0.21	$ 0.18	17%
Net income (loss)	**$1,891**	$561	237%	$(2,083)	$290	(818)%
Per boe *(6:1)*	**$1.50**	$0.70	114%	$(5.72)	$1.18	(585)%
Per share:						
Basic	**$0.07**	$0.03	133%	$(0.08)	$0.01	(900)%
Diluted	**$0.07**	$0.03	133%	$(0.08)	$0.01	(900)%
Weighted average shares outstanding:						
Basic	**25,885**	21,239	22%	25,900	25,847	0%
Diluted	**25,923**	21,239	22%	25,900	25,847	0%

The Company issued 6.1 million shares at September 28, 2007 to acquire Greenbank Energy Ltd. which is the primary reason for the increase in weighted average shares outstanding for 2008 versus 2007.

Funds from operations for the year ended December 31, 2008 more than doubled over 2007 as production and price increases more than offset the increase in royalties, operating, G&A and interest costs. On a per-boe basis, 2008 funds from operations increased by 71 percent from 2007 primarily for the same reasons except for the reduction in

G&A and interest costs. For the fourth quarter of 2008 funds from operations increased by 16 percent on an absolute basis from the prior year's periods primarily as the increase in production more than offset the increase in royalties and G&A costs and decreases in prices. On a per boe basis funds from operations for the fourth quarter of 2008 decreased 21 percent from the prior year due to lower prices, higher royalties and operating costs partially offset by a decrease in G&A and interest costs. On a per share basis, funds from operations increased 118 percent in 2008 versus 2007 and increased 17 percent in the fourth quarter of 2008 over the same quarter in 2007. The Company posted a 237 percent increase in net income for the year ended 2008 versus 2007 despite higher depletion expense combined with the write-off of goodwill in the third quarter. Higher depletion expense caused Rock to post a net loss for the fourth quarter of 2008 compared to net income for the prior year period.

CAPITAL EXPENDITURES

($000)	**12 Months Ended 12/31/08**	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Land	**$ 5,688**	$ 3,723	52%	$ 887	$ 457	94%
Seismic	**1,614**	1,359	19%	487	56	777%
Drilling and completions	**28,004**	15,799	68%	8,407	4,801	51%
Facilities & natural gas gathering systems [1]	**14,095**	1,584	1,932%	(88)	1,431	(113)%
Capitalized G&A	**1,592**	2,004	(21)%	400	589	(32)%
Total operations	**$ 50,993**	$ 24,469	108%	$ 10,093	$ 7,334	38%
Property acquisitions (dispositions) [2]	**(1,243)**	28,127	(104)%	Nil	Nil	n/a
Well site facilities inventory	**344**	94	266%	(833)	(19)	4,381%
Office equipment	**78**	1,012	(92)%	(4)	173	(102)%
Total (net of acquisitions and dispositions)	**$ 50,172**	$ 53,702	(7)%	$ 9,256	$ 7,488	24%

(1) Note items have been reclassified from drilling and completion costs to facilities and natural gas gathering systems to better reflect spending categories.

(2) Property acquisitions for 2007 have been restated from the third quarter 2007 report to be presented as the amount allocated to property plant and equipment versus the consideration paid.

Capital expenditures for operations more than doubled for the year ended December 31, 2008 compared to 2007 as Rock drilled 33 (24.3 net) wells in 2008 versus 16 (12.2 net) wells in 2007. Facilities and natural gas gathering expenditures also increased due to the compression and pipeline facilities that were constructed and brought on stream at Saxon in the first half of 2008 and due to the completion of tie-in operations in the Musreau and Kakwa areas in the first quarter of 2008.

Plains core area drilling is broken down as follows over the last two years:

	2008	2007
Heavy oil	18 (18.0 net)	8 (8.0 net)
Natural gas	nil	1 (0.9 net)
Dry hole	1 (1.0 net)	1 (1.0 net)
Total	19 (19.0 net)	10 (9.9 net)

All of the heavy oil wells were placed on production in 2008 which increased production from 1,140 bbl/day in January 2008 to 1,440 bbl/day in December 2008.

West Central core area drilling is broken down as follows over the last two years:

	2008	2007
Saxon	1 (1.0 net)	1 (1.0 net)
Tony Creek	2 (0.9 net)	nil
Girouxville	2 (0.9 net)	nil
Musreau/Kakwa	1 (0.2 net)	3 (0.9 net)
Markerville	1 (0.2 net)	nil
Elmworth	7 (2.1 net)	1 (0.3 net)
Dry hole	nil	1 (0.1 net)
Total	14 (5.3 net)	6 (2.3 net)

Rock operated 5 (2.5 net) of the West Central wells in 2008 compared to 2 (1.3 net) wells in 2007. All of the wells drilled in 2008 were brought on-stream in 2008 except for 2 (0.6 net) Elmworth wells which were delayed until the first quarter of 2009 behind a compression expansion. West Central core area production has increased from 1,070 boe/day in January 2008 to 2,300 boe/day in December 2008 with the majority of the production increase coming from Saxon and Elmworth.

Land and seismic expenditures increased in 2008 versus 2007 as the Company added undeveloped acreage and acquired seismic at Elmworth and Saxon in the West Central core area and in the Plains core area. Total net capital expenditures decreased to $50.2 million in 2008 versus $53.7 million in 2007 as minor non-core property dispositions were completed in 2008 versus the acquisition of Greenbank in 2007.

LIQUIDITY AND CAPITAL RESOURCES

Rock's current approved capital budget for 2009 projects spending of $15 million. In 2009 funds from operations is expected to be approximately $17.5 million. Approximately 30 percent of the capital budget is expected to be spent in the first four months of the year with the majority of these costs already incurred at Saxon. The balance of the budget is expected to be spent after spring break-up with almost of half it being spent in the third quarter of 2009. At year-end 2008 Rock had debt of $39 million against bank line of $51 million. The Company's debt-to-funds from operations ratio was 0.9:1 at year-end based on annual 2008 results; however this ratio has risen to 1.75:1 based on annualized fourth quarter funds from operations. The ratio is expected to rise again in 2009 to approximately 2.9:1 in the first quarter but falling to 1.7:1 in the fourth quarter and averaging 2.1:1 on an annual basis based on current projections.

The projected debt-to-funds from operations ratio is higher than our target of 1.5:1 as commodity prices have fallen significantly since the third quarter of 2008, Rock's wellhead prices have decreased over 50 percent from a high of $89.57/boe in July 2008 to $34.60/boe in December 2008. As a result, we plan to restrict capital expenditures to be less than funds from operations which should reduce bank debt from year-end 2008 levels. Should commodity prices fall below our current projections, we would look at reducing capital expenditures further and expect to shut-in operations that are not producing positive field netback.

The Company has a demand operating loan facility with a Canadian chartered bank. The facility is subject to the bank's valuation of the Company's oil and natural gas assets and the credit currently available is $51 million. The facility bears interest at the bank's prime rate or at the prevailing bankers' acceptance rate plus an applicable bank fee, which varies depending on the Company's debt-to-funds from operations ratio. The facility also bears a standby charge for undrawn amounts. The facility is secured by a first ranking floating charge on all real property of the Company, its subsidiary and partnership and a general security agreement. The next annual review for the facility is scheduled to be completed by April 30, 2009. As at March 11, 2009 approximately $32.8 million was drawn under the facility.

SELECTED ANNUAL DATA

The following table provides selected annual information for Rock:

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	12 Months Ended 12/31/06
Production *(boe/d)*	**3,436**	2,198	2,098
Oil and natural gas revenues ($000)	**$ 80,138**	$ 36,042	$ 33,156
Average realized price *($/boe)*	**$ 63.73**	$ 44.93	$ 43.27
Royalties *($/boe)*	**$ 13.59**	$ 8.77	$ 8.98
Operating expense *($/boe)*	**$ 13.81**	$ 12.37	$ 12.08
Field netback *($/boe)*	**$ 36.33**	$ 23.79	$ 22.21
Net G&A expense ($000)	**$ 3,236**	$ 2,739	$ 2,278
Stock-based compensation ($000)	**$ 1,158**	$ 931	$ 1,188
Funds from operations ($000)	**$ 40,747**	$ 15,189	$ 13,867
Per share – basic	**$ 1.57**	$ 0.72	$ 0.71
Per share – diluted	**$ 1.57**	$ 0.72	$ 0.71
Net income (loss)	**$ 1,891**	$561	($884)
Per share – basic	**$0.07**	$0.03	($0.05)
Per share – diluted	**$0.07**	$0.03	($0.05)
	As at 12/31/08	As at 12/31/07	As at 12/31/06
Total assets	**$ 150,510**	$ 130,495	$ 85,380
Total liabilities	**$ 61,488**	$ 44,301	$ 24,901

SELECTED QUARTERLY DATA

The following table provides selected quarterly information for Rock:

	3 Months Ended 12/31/08	3 Months Ended 09/30/08	3 Months Ended 06/30/08	3 Months Ended 03/31/08	3 Months Ended 12/31/07	3 Months Ended 09/30/07	3 Months Ended 06/30/07	3 Months Ended 03/31/07
Production *(boe/d)*	**3,959**	3,526	3,454	2,798	2,672	1,965	2,036	2,114
Oil and natural gas revenues *($000)*	**$15,670**	$24,424	$24,756	$15,294	$11,124	$8,106	$8,279	$8,553
Average realized price *($/boe)*	**$43.02**	$75.27	$78.80	$60.06	$45.26	$44.85	$44.66	$44.84
Royalties *($/boe)*	**$9.24**	$16.02	$16.53	$13.11	$8.21	$9.18	$9.23	$8.66
Operating expense *($/boe)*	**$14.99**	$13.08	$14.26	$12.48	$12.28	$12.38	$12.10	$12.75
Field netback *($/boe)*	**$18.79**	$46.17	$48.01	$34.47	$24.77	$23.29	$23.33	$23.43
Net G&A expense *($000)*	**$991**	$687	$765	$793	$955	$528	$530	$726
Stock-based compensation *($000)*	**$239**	$312	$315	$292	$216	$207	$241	$267
Funds from operations *($000)*	**$5,516**	$13,906	$13,785	$7,540	$4,735	$3,397	$3,536	$3,521
Per share – basic	**$0.21**	$0.54	$0.53	$0.29	$0.18	$0.17	$0.18	$0.18
Per share – diluted	**$0.21**	$0.53	$0.53	$0.29	$0.18	$0.17	$0.18	$0.18
Net income (loss) *($000)*	**$(2,083)**	($1,266)	$4,020	$1,220	$290	$15	($117)	$373
Per share – basic	**($0.08)**	($0.05)	$0.16	$0.05	$0.01	$0.00	($0.01)	$0.02
Per share – diluted	**($0.08)**	($0.05)	$0.15	$0.05	$0.01	$0.00	($0.01)	$0.02
Capital expenditures *($000)*	**$9,256**	$18,174	$6,345	$16,398	$7,488	$8,367	$2,552	$7,184
	As at 12/31/08	As at 09/30/08	As at 06/30/08	As at 03/31/08	As at 12/31/07	As at 09/30/07	As at 06/30/07	As at 03/31/07
Total debt *($000)* (1)	**$38,622**	$34,903	$30,528	$37,933	$29,072	$26,589	$15,268	$16,242

(1) Total debt includes bank debt and any working capital deficiency.

Production for the fourth quarter of 2008 increased 12 percent over the preceding quarter and has continued to grow since the third quarter of 2007 mostly due to our drilling program and in part to the Greenbank acquisition completed at the end of the third quarter of 2007. During the course of 2008 the Company has been successful at increasing heavy oil production in our Plains core area and natural gas and NGL production in our West Central core area, particularly at Saxon and Elmworth. The field netback for the first three quarters of 2008 almost doubled levels achieved in 2007 primarily due to strong commodity prices. The rapid decline of commodity prices in the fourth quarter of 2008 caused the field netback to fall below 2007 levels. Royalties reflected increases in revenues but remained fairly constant at about a 21 percent average rate. Operating costs pressures were experienced, particularly for trucking, fuel, and well servicing costs for heavy oil, and were higher on a per boe basis. G&A expenses are generally higher in the fourth quarters of any particular year due to costs associated with year-end reporting. In 2008 G&A expenses were higher than in 2007 due to increased activity levels but lower on a per boe basis. Funds from operations (on an absolute and per share basis) improved with higher production and stronger field netbacks (for the first three quarters of 2008). Net income (on an absolute and per share basis) improved in the first half of 2008 over 2007 levels based on higher funds from operations. In the last half of 2008 the Company reported net losses as a result of a $5.7 million write down of goodwill in the third quarter due to equity market conditions and higher depletion expenses.

Net capital expenditures (excluding acquisitions and dispositions) essentially doubled in 2008 over 2007 levels due to increased drilling activity, land acquisitions and seismic operations in both our core areas. Negative working capital also increased in 2008 over the previous quarter as capital spending exceeded funds from operations in all quarters of 2008 except the second quarter due to spring break-up conditions.

Reserves

Rock's reserves have been independently evaluated by GLJ Petroleum Consultants Ltd. (GLJ) at year-end 2008. This is the fifth year that GLJ has evaluated the Company's reserves. The reserves as at December 31, 2008 and 2007 have been evaluated in accordance with *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101)*. The following tables provide a reconciliation of the Company's reserves between year-end 2008 and year-end 2007 on a gross basis (before deducting royalties and without including any royalty interest) (gross interest).

Rock's gross interest reserves at year-end 2008 are 5.8 million boe of proved reserves and 10.2 million boe of proved plus probable reserves. The growth in gross interest reserves resulted from oil and natural gas operations (net of revisions) which added 1.8 million boe of proved reserves and 2.1 million boe of proved plus probable reserves. Proved producing reserves have increased to 46 percent of proved plus probable reserves on a gross interest basis at year-end 2008 from 38 percent at year-end 2007 as a significant amount of capital was spent developing proved reserves and proving up probable reserves, particularly in the West Central core area. The breakdown of reserves on a commodity basis has changed slightly on a proved plus probable basis from 2007 to 2008 with heavy oil now comprising 46 percent of reserves (up from 40percent in 2007) and natural gas comprising 45 percent of reserves (down from 50 percent in 2007). During 2008 the Company sold 0.05 million of proved and 0.07 million of proved plus probable gross interest reserves.

RESERVES RECONCILIATION

The following table is a reconciliation of Rock's gross interest reserves at December 31, 2008 using GLJ's forecast pricing and cost estimates as at December 31, 2008.

Reconciliation of Company Gross Interest Reserves by Principal Product Type (Forecast Prices and Costs)

	Light and Medium Oil		NGL		Heavy Oil		Natural Gas		Total Oil Equivalent	
Factors	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mmcf)	Proved Plus Probable (mmcf)	Proved (mboe)	Proved Plus Probable (mboe)
December 31, 2007	383	572	207	360	2,275	3,764	14,717	27,677	5,318	9,309
Additions[1]	0	0	48	67	1,000	1,741	2,487	3,589	1,462	2,406
Technical revisions[2]	(29)	(115)	227	230	(185)	(346)	2,068	(8)	359	(231)
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	(0)	(0)	(2)	(2)	0	0	(309)	(418)	(53)	(72)
Production	(71)	(71)	(88)	(88)	(486)	(486)	(3,667)	(3,667)	(1,258)	(1,258)
December 31, 2008	284	386	392	567	2,603	4,673	15,295	27,173	5,828	10,154

[1]Additions include discoveries, extensions, infill drilling and improved recovery.
[2]Technical revisions include technical revisions and economic factors.
Note: Figures may not add due to rounding; mbbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe.

RESERVES AND NET PRESENT VALUE (FORECAST PRICES AND COSTS)

The following tables summarize Rock's remaining gross interest reserves volumes along with the value of future net revenue utilizing GLJ's forecast pricing and cost estimates as at December 31, 2008.

Reserves

Reserves Category	Light and Medium Oil (mbbl)	NGL (mbbl)	Heavy Oil (mbbl)	Natural Gas (mmcf)	Total Oil Equivalent (mboe)
Proved					
Proved producing	263	335	1,963	12,779	4,692
Proved non-producing	20	12	156	1,170	383
Proved undeveloped	0	44	485	1,345	753
Total proved	283	392	2,603	15,295	5,828
Probable additional	103	175	2,070	11,878	4,327
Total proved plus probable	386	567	4,673	27,173	10,154

Note: Figures may not add due to rounding; mbbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe..

Net Present Value of Future Net Revenue

($000)	Before Income Taxes Discounted at (% per year)					After Income Taxes Discounted at (% per year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Proved producing	135,106	114,195	99,586	88,764	80,395	129,769	110,505	96,923	86,779	78,876
Proved non-producing	10,106	7,522	5,965	4,909	4,141	7,702	5,692	4,523	3,744	3,183
Proved undeveloped	13,657	10,361	8,031	6,326	5,043	10,175	7,504	5,643	4,299	3,300
Total proved	158,870	132,077	113,582	100,000	89,579	147,646	123,701	107,089	94,822	85,538
Probable additional	116,782	83,892	63,884	50,497	40,955	87,107	61,954	46,686	36,501	29,089
Total proved plus probable	275,652	215,969	177,466	150,496	130,534	234,753	185,655	153,775	131,323	114,627

Note: Figures may not add due to rounding.

PRICING ASSUMPTIONS

The following benchmark prices, inflation rates and exchange rates were used by GLJ for the forecast prices and costs evaluation.

Summary of Pricing and Cost Rate Assumptions at December 31, 2008 – Forecast Prices and Costs

	Oil				NGL				Natural Gas		
Year	WTI Cushing (US$/bbl)	Edmonton Reference Price ($/bbl)	Cromer Medium 29° API ($/bbl)	Hardisty Heavy 12° API ($/bbl)	Edmonton Propane ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Pentane ($/bbl)	Ethane ($/bbl)	AECO-C ($/mcf)	US$/Cdn$ Exchange Rate	Cost Inflation Rate (%/year)
2009	57.50	68.61	59.00	43.10	43.22	52.14	69.98	25.55	7.58	0.825	2
2010	68.00	78.94	68.68	49.76	49.73	61.57	80.52	26.80	7.94	0.850	2
2011	74.00	83.54	73.52	54.35	52.63	65.16	85.21	28.19	8.34	0.875	2
2012	85.00	90.02	80.01	59.23	57.28	70.92	92.74	29.43	8.70	0.925	2
2013	92.01	95.91	84.40	62.54	60.42	74.81	97.82	30.27	8.95	0.950	2
2014	93.85	97.84	86.10	63.82	61.64	76.32	99.80	30.94	9.14	0.950	2
2015	95.73	99.82	87.84	65.13	62.89	77.86	101.81	31.62	9.34	0.950	2
2016	97.64	101.83	89.61	66.46	64.15	79.43	103.87	32.31	9.54	0.950	2
2017	99.59	103.89	91.42	67.83	65.45	81.03	105.97	33.02	9.75	0.950	2
2018	101.59	105.99	93.27	69.22	66.77	82.67	108.10	33.74	9.95	0.950	2
2019+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.950	2

FINDING, DEVELOPMENT AND ACQUISITION COSTS

The following table summarizes Rock's finding, development and acquisition costs for the years ended December 31, 2008, 2007 and 2006, including future development costs.

	12 months ended Dec. 31, 2008	12 months ended Dec. 31, 2007	12 months ended Dec. 31, 2006	3 Year Cumulative Total
Oil and Natural Gas Operations:				
Proved finding and development costs				
Capital expenditures[(1)] *($000)*	**$50,939**	$24,163	$32,907	$108,009
Change in future capital costs *($000)*	**(2,948)**	3,501	2,939	3,492
Total capital *($000)*	**$47,991**	$27,664	$35,846	$111,501
Reserve additions[(2)] *(mboe)*	**1,462**	949	2,181	4,592
Proved finding and development costs *($/boe)*	**$32.82**	$29.15	$16.44	$24.28
Proved plus probable finding and development costs				
Capital expenditures[(1)] *($000)*	**$50,939**	$24,163	$32,907	$108,009
Change in future capital costs *($000)*	**3,106**	3,930	7,986	15,022
Total capital *($000)*	**$54,045**	$28,093	$40,893	$123,031
Reserve additions[(2)] *(mboe)*	**2,406**	1,506	3,624	7,536
Proved plus probable finding and development costs *($/boe)*	**$22.46**	$18.66	$11.28	$16.33
Acquisitions/Dispositions:				
Proved finding and development costs – acquisitions (dispositions)				
Capital expenditures[(1)] *($000)*	**($1,190)**	$28,524	($30,878)	($3,544)
Change in future capital costs *($000)*	**(17)**	4,136	(2,400)	1,719
Total capital *($000)*	**($1,207)**	$32,660	($33,278)	($1,825)
Reserve additions *(mboe)*	**(53)**	971	(1,042)	(125)
Proved finding and development costs *($/boe)*	**$22.59**	$33.64	$31.94	$14.65

Proved plus probable finding and development costs – acquisitions (dispositions)				
Capital expenditures[1] *($000)*	**($1,190)**	$28,524	($30,878)	($3,544)
Change in future capital costs *($000)*	**(17)**	11,417	(2,400)	9,000
Total capital *($000)*	**($1,207)**	$39,941	($33,278)	$5,456
Reserve additions *(mboe)*	**(72)**	1,898	(1,406)	419
Proved plus probable finding and development costs *($/boe)*	**$16.69**	$21.05	$23.67	$13.01
Total Activities:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	**$49,750**	$52,687	$2,029	$104,465
Change in future capital costs *($000)*	**(2,965)**	7,637	539	5,211
Total capital *($000)*	**$46,785**	$60,324	$2,568	$109,676
Reserve additions[3] *(mboe)*	**1,768**	1,643	1,279	4,690
Total proved finding and development costs *($/boe)*	**$26.46**	$36.72	$2.01	$23.39
Proved plus probable finding and development costs				
Capital expenditures[1] *($000)*	**$49,750**	$52,687	$2,029	$104,465
Change in future capital costs *($000)*	**3,089**	15,347	5,586	24,022
Total capital *($000)*	**$52,839**	$68,034	$7,615	$128,487
Reserve additions[3] *(mboe)*	**2,103**	2,786	2,153	7,042
Total proved plus probable finding and development costs *($/boe)*	**$25.13**	$24.42	$3.54	$18.24

(1) Capital expenditures include capitalized G&A which has been allocated between oil and natural gas operations and acquisitions, and exclude purchases of equipment still held in inventory and administrative capital expenditures.

(2) Reserve additions exclude revisions.

(3) Reserve additions include revisions.

(4) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Finding, development and acquisition ("FD&A") costs are broken down according to oil and natural gas operations, acquisitions and dispositions, and total activities. Oil and natural gas operations include all capital activities in which the Company participated, including operations on the acquired properties after their respective closing dates, but exclude reserve revisions. FD&A costs on the acquired properties are based on the reserve evaluation as at each respective year end less new reserves from operations post closing and were increased by the amount of production from the closing date to December 31 of the respective year to provide an estimate of the reserves purchased. FD&A costs on the disposed properties are based on the reserve evaluation as at December 31, of the year prior to the closing date and were decreased by the amount of production to the closing date. FD&A costs for total activities include operations, acquisitions, dispositions and reserve revisions.

Finding and development costs on operations increased in 2008 compared to 2007 and 2006 as Rock spent more capital in the higher cost West Central core area versus the relatively less expensive Plains core area and increased land expenditures over prior years. Capital spending in the West Central core area includes $14 million for infrastructure spending at Saxon and Musreau/Kakwa. Reserve bookings increased at Saxon based on well performance however, Musreau/Kakwa wells have not performed as well as expected. New reserve bookings at Elmworth have been lower than expected but there is little production history with these wells and we do expect some upward revisions in the future. FD&A costs for the West Central core area have been higher than expected in part due to the high infrastructure component and lower initial reserve bookings at Elmworth based on early results. In the Plains core area remediation efforts to solve the gas migration issue at our Edam heavy oil property were slowed by the industry approval process. As a result only one of the three affected wells was on production for a significant amount of time in 2008. A second well was placed on production late in 2008 and a third well should be on production in mid 2009. Production from the first remediated well has been more encouraging lately and Management still believes more reserves will ultimately be recoverable at Edam. In addition Rock started to experience higher water cuts in some wells at our Upgrader heavy oil property and a negative reserve revision has been booked as a result. Longer term well performance will be required to determine ultimate recovery. Of the heavy oil wells drilled in 2008, 15 (15.0 net) have reserves assigned as expected, however 3 (3.0 net) wells experienced production issues within months after completion have no reserves assigned to them. FD&A costs for the Plains core area are generally in line with our expectations. Overall, FD&A costs for 2008 are high. On a three year basis the FD&A costs are more reflective of the progress made in growing the Company and generate recycle ratios (FD&A divided by operating netback) of 1.8:1 for operations and 1.6:1 overall.

LAND HOLDINGS

The following table summarizes Rock's land holdings as at December 31, 2008 and 2007:

(acres)		Dec. 31, 2008	Dec. 31, 2007	Change
Developed	– Gross	**81,091**	87,882	(8)%
	– Net	**30,739**	32,406	(5)%
Undeveloped	– Gross	**135,573**	135,069	0%
	– Net	**80,574**	61,718	31%
Total	– Gross	**216,664**	222,951	(3)%
	– Net	**111,313**	94,123	18%

NET ASSET VALUE

The following table summarizes Rock's net asset value and net asset value per share as at December 31, 2008 and December 31, 2007:

($000 except number of shares and net asset value per share)	December 31, 2008	December 31, 2007	Change
Proved plus probable reserves(1) (2)	**177,466**	152,420	20%
Undeveloped land(3)	**15,425**	13,380	15%
Working capital including debt	**(38,622)**	(29,094)	33%
Net asset value	**154,269**	136,706	16%
Year-end shares outstanding *(000)*	**25,900**	25,878	0%
Net asset value per share	**$5.96**	$5.28	16%
Option proceeds	**5,390**	7,893	(32)%
Net asset value	**159,659**	144,599	14%
Fully diluted shares outstanding *(000)*	**27,644**	28,185	(2)%
Net asset value per share (fully diluted)	**$5.78**	$5.13	16%

(1) Proved plus probable reserves value is based on the net present value of future net revenue from gross reserves using GLJ Petroleum Consultants Ltd.'s January 2008 and 2007 forecast pricing and costs estimates and using a discount rate at 10 percent. Net present value of future net revenue does not represent fair market value.

(2) Reserve values are based on the new Alberta royalty regime for year-end 2008 and the existing Alberta royalty regime for year-end 2007. Note the range of reserve values for 2007 under a high and low royalty assumption case for the new Alberta royalty regime was $144,747 to $152,420 as disclosed in the 2007 Annual Report.

(3) Undeveloped land value is based on the actual cost of land purchased at land sales; land acquired from ELM/Optimum/Qwest in the second quarter of 2005 has been valued at $100 per acre and land acquired through the Greenbank acquisition in the third quarter of 2007 has been valued at $200 per acre.

CONTRACTUAL OBLIGATIONS

In the course of its business, the Company enters into various contractual obligations including the following:

- royalty agreements;
- processing agreements;
- right-of-way agreements; and
- lease obligations for office premises.

Obligations with a fixed term are as follows:

	2009	2010	2011	2012	2013
Office premise leases	$ 828	$ 828	$ 828	$ 552	$ nil
Processing agreements	360	288	238	159	nil
Demand bank loan[1]	$34,175	$-	$-	$-	$-

[1] *The demand bank loan is currently under its annual review and is expected to remain in place.*

OUTSTANDING SHARE DATA

At December 31, 2008 and to date, Rock had 25,889,843 common shares outstanding. At December 31, 2008 the Company had 1,744,204 stock options outstanding with an average exercise price of $3.09 per share. As of the date hereof Rock has 1,688,871 options outstanding.

OFF-BALANCE-SHEET ARRANGEMENTS

Rock does not have any special-purpose entities nor is it party to any arrangement that would be excluded from the balance sheet.

RELATED-PARTY TRANSACTIONS

The Company has not entered into any related-party transactions during the reporting period.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year-end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year-end of the Company for the foregoing purposes. All control systems by their nature have inherent limitations and, therefore, Rock's disclosure controls and procedures are believed to provide reasonable, but not absolute, assurance that:

- the communications by the Company with the public are timely, factual and accurate and broadly disseminated in accordance with all applicable legal and regulatory requirements;
- non-publicly disclosed information remains confidential; and

• trading of the Company's securities by directors, officers and employees remains in compliance with applicable securities laws.

INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal control over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with the Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal control over financial reporting at the financial year end of the Company and concluded that the Company's internal control over financial reporting is effective, at the financial year end of the Company, for the foregoing purpose.

The Company is required to disclose herein any change in the Company's internal control over financial reporting that occurred during the period beginning on October 1, 2008 and ended on December 31, 2008 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period, that has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

It should be noted a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

CHANGE IN ACCOUNTING POLICIES

As of January 1, 2008 the Company adopted new policies to implement the pronouncements from the Canadian Institute of Chartered Accountants ("CICA") in respect of capital disclosures and financial instruments - presentation and disclosures. The new standard for capital disclosures requires disclosure on objectives, policies and processes for managing capital. The new standard for financial instruments places increased emphasis and disclosure on the nature and extent of risks arising from financial instruments and how they are managed. The application of these policies did not result in changes to amounts reported in the consolidated financial statements for the period ended December 31, 2008.

NEW ACCOUNTING PRONOUNCEMENTS

Goodwill and Intangible Assets

The CICA in February 2008 issued CICA Handbook section 3064, Goodwill and Intangible Assets, and amended section 1000, Financial Statement Concepts, clarifying the criteria for recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets.

Rock will adopt this section effective January 1, 2009.

International Financial Reporting Standards

In February 2008 the CICA confirmed the implementation of International Financial Reporting Standards ("IFRS") as part of Canadian GAAP. The adoption of IFRS in Canada will result in significant changes to current Canadian GAAP and to financial reporting practices followed by Rock. IFRS accounting standards are to be implemented for years beginning after December 31, 2010. Rock will be required to adopt the standard for the year beginning January 1, 2011.

Rock has participated in an industry task force which has identified issues, helped understand the new accounting policies and the choices that can be made and provided guidance regarding the adoption of IFRS for the oil and natural gas industry. In order to transition to IFRS the Company will have to adopt new accounting policies, procedures and reporting standards. As part of this process Rock will have to transition from the full cost method of accounting, which the Company currently follows, to a method acceptable under IFRS. At a minimum IFRS will require the Company to identify new units of account and cash generating units at a more finite level than under full cost accounting and will also require asset impairment testing at the new unit levels. Setting new IFRS accounting policies and the identification of cash generating units will begin in the second quarter of 2009 but not likely completed until the fourth quarter of 2009. It is likely Rock will need to put in place a new accounting system in order to more effectively handle IFRS accounting procedures. Rock will begin to investigate new systems in the second quarter of 2009 with the intent of having a new system in place and operating by January 2010. Currently IFRS is proposing an amendment that, if successful, would allow Canadian companies using the full cost method of accounting for exploration and development activities to utilize their independent reserve report to allocate certain property, plant and equipment costs to newly defined units of account at the time of transition to IFRS. The proposed amendment would significantly reduce the amount of work required to transition the Company to IFRS. The Company intends to have an opening balance sheet that is IFRS compliant for January 1, 2010 at which point both IFRS and Canadian GAAP compliant financial statements will be maintained in order to facilitate full IFRS compliant reporting effective January 1, 2011. Rock will have in-house staff attend training courses specific to IFRS adoption and policies. Rock may engage external consultants to help with the transition and adoption of IFRS.

Business Combinations

In January 2009, the CICA issued new standards for Business Combinations. This standard is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This standard replaces, Business Combination and harmonizes the Canadian standards with IFRS. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a significant impact on the way the Company accounts for future business combinations.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Company's significant accounting policies is contained in note 2 to the audited consolidated financial statements. These accounting policies are subject to estimates and key judgements about future events, many of which are beyond Rock's control. The following is a discussion of the accounting estimates that are critical to the financial statements.

Oil and Natural Gas Accounting – Reserves Recognition – Rock retained independent petroleum engineering consultants GLJ Petroleum Consultants Ltd. (GLJ) to evaluate its oil and natural gas reserves, prepare an evaluation report, and report to the Company's Reserves Committee. The process of estimating oil and natural gas reserves is subjective and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data. These estimates will change over time as additional data from ongoing development and production activities becomes available and as economic conditions affecting oil and natural gas prices and costs change. Reserves can be classified as proved, probable or possible with decreasing levels of certainty to the likelihood that the reserves will be ultimately produced.

Oil and Natural Gas Accounting – Full Cost Accounting – Under the full cost method of accounting for exploration and development activities, all costs associated with these activities are capitalized. The aggregate net capitalized costs and estimated future abandonment costs, less estimated salvage values, are amortized using the unit-of-production method based on estimated proved oil and natural gas reserves, resulting in a depletion expense. The depletion expense is most affected by the estimate of proved reserves and the cost of unproved properties. Unproved costs are reviewed quarterly to determine if proved reserves have been established, at which point the associated costs are included in the depletion calculation. Changes to any of these estimates may affect Rock's earnings.

Under the full cost method of accounting, the Company's investment in oil and natural gas assets is evaluated at least annually to consider whether the investment is recoverable and the carrying amount does not exceed the value of the properties, a process known as the "ceiling test". The carrying value of oil and natural gas properties and production equipment is compared to the sum of undiscounted cash flows expected to result from Rock's proved reserves. If the carrying value is not fully recoverable, the amount of impairment is measured by comparing the carrying value of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves using a risk-free interest rate. Any excess carrying value above the net present value of the future cash flows is recorded as a permanent impairment. Reserve, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the ceiling test. Revisions of these estimates could result in a write-down of the carrying amount of oil and natural gas properties.

Asset Retirement Obligations – The Company recognizes the estimated fair value of an asset retirement obligation (ARO) in the period in which it is incurred as a liability, and records a corresponding increase in the carrying value of the related asset. The future asset retirement obligation is an estimate based on the Company's ownership interest in wells and facilities and reflects estimated costs to complete the abandonment and reclamation as well as the estimated timing of the costs to be incurred in future periods. Estimates of the costs associated with abandonment and reclamation activities require judgement concerning the method, timing and extent of future retirement activities. The capitalized amount is depleted on a unit-of-production method over the life of the proved reserves. The liability amount is increased each reporting period due to the passage of time and this accretion amount is charged to earnings in the period. Actual costs incurred on settlement of the ARO are charged against the ARO. Judgements affecting current and annual expense are subject to future revisions based on changes in technology, abandonment timing, costs, discount rates and the regulatory environment.

Stock-based Compensation – Stock options issued to employees and directors under the Company's stock option plan are accounted for using the fair value method of accounting for stock-based compensation. The fair value of the option is recognized as stock-based compensation expense and contributed surplus over the vesting period of the option. Stock-based compensation expense is determined on the date of an option grant using the Black-Scholes option pricing model. The Black-Scholes pricing model requires the estimation of several variables including estimated volatility of Rock's stock price over the life of the option, estimated option forfeitures, estimated life of the option, estimated risk-free rate and estimated dividend rate. A change to these estimates would alter the valuation of the option and would result in a different related stock-based compensation expense.

BUSINESS RISKS

Rock is exposed to a number of business risks, some of which are beyond its control, as are all companies in the oil and gas exploration and production industry. These risks can be categorized as operational, financial and regulatory.

Operational risks include generating, finding and developing, and acquiring oil and natural gas reserves on an economical basis (including acquiring land rights or gaining access to land rights); reservoir production performance; marketing; production; hiring and retaining employees; and accessing contract services on a cost-effective basis. Rock attempts to mitigate these risks by employing highly qualified staff and operating in areas where employees have expertise. In addition the Company outsources certain activities to be able to lever industry expertise, without having the burden of hiring full-time staff given the current scope of operations. Typically the Company has outsourced the marketing and certain engineering and land functions. Rock is attempting to acquire existing oil and natural gas operations; however Rock will be competing against many other companies for such operations, many of which will have greater access to resources. As a small company, gaining access to contract services may be difficult given the competitive nature of the industry, but Rock will attempt to mitigate this risk by utilizing existing relationships.

Financial risks include commodity prices, the US/Canadian dollar exchange rate and interest rates, all of which are largely beyond the Company's control. Currently Rock has not used any financial instruments to mitigate these risks. The Company would consider using these financial instruments depending on the operating environment. The Company also will require access to capital. Currently Rock has a debt facility in place and intends to use its debt capacity in the future in conjunction with capital expenditures including acquisitions. It intends to use prudent levels of debt to fund capital programs based on the expected operating environment. It also intends to access equity markets to fund opportunities; however, the ability to access these markets will be determined by many factors, many of which will be beyond the control of the Company.

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Company may, in part, be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid. In the current economic climate, including the recent deterioration in commodity prices, the Company's ability to access both credit and equity markets may be compromised or prohibited as many credit lenders and equity investors are restricting funds available to companies like Rock and as a result, Rock may have to alter its future spending plans.

Rock is subject to various regulatory risks, principally environmental in nature. The Company has put in place a corporate safety program and a site-specific emergency response program to help manage these risks. The Company hires third-party consultants to help develop and manage these programs and help Rock comply with current environmental legislation. Increased public and political concern regarding climate change issues will likely result in increased regulation regarding emissions standards. Given that the Company produces hydrocarbons, such regulation could cause Rock to alter the way it operates and also result in additional costs and taxes associated with climate change regulation which could have a material effect on the Company.

ENVIRONMENTAL RISK AND REGULATION

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 federal, provincial and local laws and regulations. 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. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 emission levels. The Federal government has introduced legislation aimed at reducing greenhouse gas emissions using a "intensity based" approach, the specifics of which have yet to be determined. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. There has been much public debate with respect to Canada's ability to meet these targets and the Federal government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company.

In Alberta, the reduction emission guidelines outlined the Climate Change and Emissions Management Amendment Act (the "Act") came into effect July 1, 2007. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12 percent. Industries have three options to choose from in order to meet the reduction requirements outlined in the Act, and these are: (a) by making improvement to operations that result in reductions; (b) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emissions; or (c) by contributing to the Climate Change and Emissions Management Fund. Pursuant to the Act, March 31, 2008 was the deadline for industries to choose one of these options or a combination thereof. On April 26, 2007, the Federal government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products.

On January 24, 2008, the Alberta government announced its plan to reduce projected emissions in the province by 50% by 2050. This will result in real reductions of 14 percent below 2005 levels. The Alberta government stated it would form a government-industry council to determine a go-forward plan for implementing technologies, which will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations (carbon capture). In addition, the plan calls for energy conservation by individuals and for increased investment in clean energy technologies and incentives for expanding the use of renewable and alternative energy sources such as bioenergy, wind, solar, hydrogen, and geothermal. Initiatives under this theme will account for 18 percent of Alberta's reductions.

On January 31, 2008, the Government of Canada and the Province of Alberta released the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

On March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" which provides some additional guidance with respect to the Government of Canada's plan to reduce greenhouse gas emissions by 20 percent by 2020 and by 60 percent to 70 percent by 2050. The updated action plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and natural gas, and refining industries. The updated action plan is intended to force industry to reduce greenhouse gas emissions and to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. The updated action plan provides for: (i) mandatory reductions of 18 percent from the 2006 baseline starting in 2010 and by an addition 2 percent in subsequent years for existing facilities; (ii) new facilities built between 2004 and 2011 will have mandatory emissions standards based upon clean fuel standards (gas) with a 2 percent reduction below the third year's intensity levels; and (iii) oil sands plants built in 2012 and later which use heavier hydrocarbons and upgraders and in situ production will have mandatory standards in 2018 based on carbon capture and storage or other green technologies intensity. For the upstream oil and natural gas industry, the updated action plan also provides for a company threshold of 10,000 boe per day and facility threshold of 3,000 tonnes of C02.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Company and its operations and financial condition.

ADDITIONAL INFORMATION

Further information regarding the Company, including the Company's Annual Information Form, can be accessed under the Company's public filings found on SEDAR at www.sedar.com. Information can also be obtained by contacting Rock Energy Inc., Suite 800, 607 - 8th Avenue S.W., Calgary, Alberta, T2P 0A7.