Management's Discussion and Analysis

Rock Energy Inc. ("Rock" or the "Company") is a publicly traded energy company engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. Rock's corporate strategy is to continue to grow and develop as an oil and gas exploration and production company through internal operations and acquisitions.

Rock evaluates its performance based on net income, funds from operations, field netback, 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 financial contribution of crude oil and natural gas operations after the deduction of royalties, transportation costs and operating expenses.

Finding and development costs are another benchmark used in the oil and gas industry and are used by Rock to evaluate the capital costs incurred by the Company to find and bring reserves on-stream on a per unit basis, providing insight into the relative efficiency of capital investments.

Rock faces competition in the oil and gas industry for resources, including technical personnel and third-party services. The Company focuses on hiring and retaining personnel with the expertise to develop opportunities on existing lands and 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 (MD&A) concerning the financial and operating results of the Company for the years ended December 31, 2009 and 2008 is dated March 23, 2010 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 for the years ended December 31, 2009 and 2008.

The terms "2009" and "2008" are used throughout this document and refer to the years ended December 31, 2009 and 2008, respectively. The terms "fourth quarter of 2009" and "same period of 2008" or similar terms are used throughout this document and refer to the three-month periods ended December 31, 2009 and 2008, respectively.

ABBREVIATIONS

bbl	barrel(s)
bcf	billion cubic feet
boe	barrels of oil equivalent
bps	basis points
CDOR	Certificate of Deposit Offered Rate
GJ	gigajoule
hectare	1 hectare is equal to 2.47 acres
km	kilometre
mbbls	thousand barrels
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per day
mcf	thousand cubic feet
mmcf	million cubic feet
mmbbls	million barrels
mmboe	million barrels of oil equivalent
NGL	natural gas liquids
W.T.I.	West Texas Intermediate

GUIDANCE AND OUTLOOK

The Company issued guidance on November 12, 2009 for projected 2009 and 2010 results. The table below provides Rock's guidance for 2009 along with actual results.

2009 Guidance

	2009 Guidance	Actual	Difference
2009 production (boe/d)			
Annual	3,300 – 3,500	3,435	0%
Exit (December average)	3,400 – 3,600	3,479	0%
2009 funds from operations			
Annual	$19.6 million	$19.6 million	0%
Annual – per basic share	$0.73	$0.73	0%
2009 capital budget			
Expenditures	$19.0 million	$20.5 million	8%
Wells drilled	23 – 25	24	0%
Total year-end net debt [i]	$24.0 million	$25.3 million	5%
Pricing (fourth quarter)			
Crude oil – W.T.I.	US$75.00/bbl	US$76.19/bbl	2%
Natural gas – AECO	$4.25/mcf	$4.49/mcf	6%
Cdn$/US$ exchange rate	$0.96	$0.95	(1)%

[i] Net debt is the working capital deficiency including bank debt.

Actual 2009 results are within the guidance range for production and funds from operations. Capital expenditures were higher than forecast due to the accelerated timing of a drilling location in Elmworth originally planned for the first quarter of 2010. These higher capital expenditures contributed to year-end debt slightly exceeding the guidance level.

2010 Guidance

The table below provides Rock's guidance for 2010, which has been updated to reflect the acceleration of some planned capital spending to December 2009 from early 2010. Accordingly, the capital budget for 2010 has been reduced to $41.6 million as guidance for year-end net debt has been maintained at $34 million. With proceeds from its equity financing in October 2009 and its inventory of opportunities the Company has prepared a budget based on capital expenditures that are in excess of funds from operations. However, throughout 2010 Rock plans to maintain a balance sheet that has a debt to annualized quarterly funds from operations ratio no higher than 1:5:1. Rock's capital budget has been designed taking into account the need for winter access operations at Saxon in its West Central Alberta core area during the first quarter and heavy oil operations in the Plains core area during the first three quarters. The Company is well-positioned to monitor commodity prices and resulting funds flows and adjust its capital budget accordingly. Rock expects to drill 14 (5.7 net) natural gas wells in the West Central Alberta core area and approximately 30 (30.0 net) heavy oil wells in the Plains core area.

Crude oil prices are forecast to average US$75.00/bbl, comparable to the average realized price during the fourth quarter of 2009. Natural gas prices are forecast to average $5.75 per mcf in 2010. As a result of increased pricing, forecast royalty rates have been increased to approximately 21 percent. Operating costs are forecast at approximately $14.00 per boe while G&A costs are expected to be approximately $2.50 per boe. Interest costs on both an absolute and per boe basis are anticipated to be comparable to 2009.

The planned activities and assumptions outlined above result in a $41.6 million capital budget from which Rock is projecting 2010 annual production to increase by a range of 11 percent to 16 percent over average 2009 levels. Funds from operations of $33 million ($1.08 per basic share) are projected to increase by approximately 68 percent from 2009 levels due to higher commodity prices and production. Year-end net debt is projected to increase to $34 million with a debt to annualized fourth quarter funds from operations ratio of 0.9:1. The table below updates the Company's previous guidance that was issued on November 12, 2009.

	March 23, 2010 Guidance	November 12, 2009 Guidance
2010 production (boe/d)		
Annual	3,800 – 4,000	3,800 – 4,000
Exit (December average)	4,400 – 4,600	4,400 – 4,600
2010 funds from operations		
Annual	$33.0 million	$33.0 million
Annual – per basic share	$1.08	$1.08
2010 capital budget		
Expenditures	$41.6 million	$43.0 million
Wells drilled	40 – 45	40 – 45
Total year-end net debt	$34.0 million	$34.0 million
Pricing (annual average)		
Crude oil – W.T.I.	US$75.00/bbl	US$75.00/bbl
Natural gas – AECO	$5.75/mcf	$5.75/mcf
Cdn$/US$ exchange rate	$0.95	$0.95

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) in Canada. 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 and asset retirement expenditures. Funds from operations per share is calculated using the same methodology for determining net income (loss) per share. Rock's use of 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 (loss) 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 the years ended December 31, 2009 and 2008 is presented in the table below.

($000)	**Year Ended 12/31/09**	Year Ended 12/31/08	**Three Months Ended 12/31/09**	Three Months Ended 12/31/08
Cash provided by operating activities	**$ 17,946**	$ 41,590	**$ 9,487**	$ 6,261
Add (deduct):				
Changes in non-cash working capital	**1,586**	(843)	**(3,395)**	(745)
Asset retirement expenditures	**112**	94	**58**	4
Funds from operations	**$ 19,644**	$ 40,841	**$ 6,150**	$ 5,520

Management uses certain industry benchmarks such as field netback to analyze financial and operating performance. Field netback is calculated by taking crude oil and natural gas revenues after deducting royalties, operating costs and transportation costs, resulting in an approximation of initial cash margin in the field on crude oil and natural gas production. 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 an important measure to demonstrate profitability relative to commodity prices in the measured period.

All barrels of oil equivalent (boe) conversions in this report are derived by converting natural gas to crude oil in the ratio of six thousand cubic feet (mcf) of natural gas to one barrel (bbl) of crude 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 (Cdn$) unless otherwise noted.

PRODUCTION AND PRICES

Production by Product

	Year Ended 12/31/09	Year Ended 12/31/08	Change	**Three Months Ended 12/31/09**	Three Months Ended 12/31/08	Change
Heavy oil (bbls/d)	**1,493**	1,329	12%	**1,638**	1,537	7%
Light oil (bbls/d)	**133**	193	(31)%	**135**	169	(20)%
Natural gas (mcf/d)	**9,553**	10,048	(5)%	**8,211**	11,731	(30)%
Natural gas liquids (bbls/d)	**217**	239	(9)%	**234**	298	(21)%
Total (boe/d)	**3,435**	3,436	0%	**3,376**	3,959	(15)%

Production by Area

	Year Ended 12/31/09	Year Ended 12/31/08	Change	**Three Months Ended 12/31/09**	Three Months Ended 12/31/08	Change
West Central Alberta (boe/d)	**1,661**	1,722	(4)%	**1,490**	2,090	(29)%
Plains (boe/d)	**1,546**	1,362	14%	**1,678**	1,563	7%
Other (boe/d)	**228**	352	(35)%	**208**	306	(32)%
Total (boe/d)	**3,435**	3,436	0%	**3,376**	3,959	(15)%

Production for the year ended December 31, 2009 is comparable to the prior year with the increase in heavy oil production fully offsetting the decrease in natural gas, light oil and natural gas liquids production. For 2009, a total of 20 (20.0 net) heavy oil wells and only four (2.1 net) natural gas wells were drilled compared to 19 (19.0 net) heavy oil wells and 14 (5.3 net) natural gas wells drilled in 2008. The 20 heavy oil wells were drilled in the Plains core area which contributed to a 14 percent increase in heavy oil production in 2009. Of the 20 heavy oil wells that were drilled in 2009, 19 wells are currently producing. The four (2.1 net) natural gas wells consisted of one (1.0 net) well drilled at Saxon and three (1.1 net) wells drilled at Elmworth. Saxon and Elmworth continue to represent the two most significant properties in the West Central core area. However, with reduced drilling activity in 2009 natural gas and related natural gas liquids production declined as anticipated. The light oil production declines are attributable to a non-core property which is also experiencing natural production declines.

Production for the three months ended December 31, 2009 decreased by 15 percent from the same period last year primarily due to natural gas and natural gas liquids production declines as significant natural gas drilling activity was completed during the fourth quarter of 2008, partially offset by a 7 percent increase in heavy oil production. With improved natural gas prices, the Company anticipates drilling five natural gas wells during the first quarter of 2010 including a vertical Montney natural gas well at Elmworth in West Central Alberta. Rock also anticipates drilling 11 heavy oil wells in the Plains core area by the end of the first quarter of 2010.

Product Prices

	Year Ended 12/31/09	Year Ended 12/31/08	Change	Three Months Ended 12/31/09	Three Months Ended 12/31/08	Change
Realized Product Prices						
Heavy oil ($/bbl)	**53.31**	71.58	(26)%	**61.82**	40.17	54%
Light oil ($/bbl)	**60.59**	95.86	(37)%	**72.18**	57.20	26%
Natural gas ($/mcf)	**4.20**	8.72	(52)%	**4.38**	7.27	(40)%
Natural gas liquids ($/bbl)	**42.42**	74.15	(43)%	**49.96**	45.78	9%
Combined average ($/boe)	**39.89**	63.73	(37)%	**47.00**	43.02	9%

	Year Ended 12/31/09	Year Ended 12/31/08	Change	Three Months Ended 12/31/09	Three Months Ended 12/31/08	Change
Average Reference Prices						
Crude Oil – W.T.I. Cushing, Oklahoma (US$/bbl)	**61.81**	99.65	(38)%	**76.19**	58.73	30%
Crude Oil – Edmonton light (Cdn$/bbl)	**65.90**	102.16	(36)%	**76.56**	63.21	21%
Heavy oil – Western Canadian Select (WCS) (Cdn$/bbl)	**58.66**	82.90	(29)%	**67.65**	47.72	42%
Natural gas – Henry Hub Daily Spot (US$/mmbtu)	**3.90**	8.88	(56)%	**4.18**	6.47	(35)%
Natural gas – AECO C Daily Spot (Cdn$/mcf)	**3.96**	8.16	(51)%	**4.49**	6.70	(33)%
Cdn$/US$ exchange rate	**0.880**	0.943	(7)%	**0.947**	0.825	15%

For 2009, average realized commodity prices of $39.89 per boe were 37 percent lower than in 2008. However, throughout 2009 the Company experienced a continued improvement in commodity prices, particularly for crude oil-based products. For the three months ended December 31, 2009 natural gas prices decreased significantly from the same period in 2008 but were fully offset by crude oil price increases.

Heavy oil prices increased not only due to the rising W.T.I. price since the first quarter of 2009 but also as a result of a significant narrowing of the heavy to light oil price differentials relative to 2008. In the fourth quarter of 2009, the realized heavy oil price was $61.82 per bbl as differentials relative to the Edmonton light par price were only 19 percent compared to 36 percent in the fourth quarter of 2008. Similarly, for the year ended December 31, 2009 the differential between the realized heavy oil price of $53.31 per barrel and the Edmonton light par price was 19 percent compared to 30 percent in 2008. In 2009, the Company realized its lowest combined price of $32.55 per boe in February while the highest realized average price was $47.25 per boe in December. In the first quarter of 2010 heavy oil differentials have remained narrow, resulting in a 2010 estimated heavy oil wellhead price in excess of $60.00 per bbl at a W.T.I. price of approximately US$75.00 per barrel.

Natural gas price declines are primarily attributable to reduced industrial demand and current high inventory levels. The futures market indicates that natural gas prices should improve with forecast AECO prices of approximately $5.75 per mcf for 2010.

Rock has not hedged any of its commodity prices on production at this time.

REVENUE

($000)	Year Ended 12/31/09	Year Ended 12/31/08	Change	Three Months Ended 12/31/09	Three Months Ended 12/31/08	Change
Heavy oil	**$ 29,095**	$ 34,813	(16)%	**$ 9,317**	$ 5,681	64%
Light oil	**2,940**	6,780	(57)%	**899**	889	1%
Natural gas	**14,632**	32,190	(55)%	**3,307**	7,921	(58)%
Natural gas liquids	**3,358**	6,493	(48)%	**1,074**	1,255	(14)%
	$ 50,025	$ 80,276	(38)%	**$ 14,597**	$ 15,746	(7)%

For 2009, crude oil and natural gas revenue decreased by 38 percent from 2008 and was significantly impacted by lower commodity prices as Rock's annual average realized product prices decreased by 37 percent from 2008. For the three months ended December 31, 2009 the decrease in crude oil and natural gas revenue of only 7 percent was primarily attributable to increased heavy oil pricing and production partially offset by decreased natural gas pricing and production.

ROYALTIES

	Year Ended 12/31/09	Year Ended 12/31/08	Change	Three Months Ended 12/31/09	Three Months Ended 12/31/08	Change
Royalties ($000)	**$ 9,140**	$ 17,094	(47)%	**$ 2,599**	$ 3,366	(23)%
As a percentage of crude oil and natural gas revenue	**18.3%**	21.3%	(14)%	**17.8%**	21.6%	(18)%
Per boe	**$ 7.29**	$ 13.59	(46)%	**$ 8.37**	$ 9.24	(9)%

Royalties for 2009 were lower on an absolute, percentage and per boe basis than in 2008. The reduction in royalty rates is primarily a result of significantly reduced commodity prices. For the fourth quarter of 2009 the lower royalties are also reflective of reduced production levels and a royalty incentive program initiated by the Alberta government in 2009. The royalty incentive program allows for a reduced Crown royalty rate of 5 percent for new wells tied in for production on Crown lands from April 1, 2009 to March 31, 2011. The incentive is subject to a limit based on either 12 months of production, 50,000 bbls of crude oil production or 500 mmcf of natural gas production, whichever is reached first. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5 percent for the first 12 months of production would be made permanent with the same volume limitations. Based on Rock's projected product prices for 2010 the royalty rates are forecast at approximately 21 percent of crude oil and natural gas revenue.

OPERATING EXPENSE

($000 except per boe)	**Year Ended 12/31/09**	Year Ended 12/31/08	Change	**Three Months Ended 12/31/09**	Three Months Ended 12/31/08	Change
Operating costs	**$ 16,015**	$ 16,456	(3)%	**$ 4,286**	$ 5,207	(18)%
Transportation costs	**780**	905	(14)%	**215**	251	(14)%
	$ 16,795	$ 17,361	(3)%	**$ 4,501**	$ 5,458	(18)%
Per boe	**$ 13.40**	$ 13.81	(3)%	**$ 14.49**	$ 14.99	(3)%

Operating expenses in 2009 decreased on an absolute and per boe basis from 2008. For the fourth quarter of 2009 operating costs were 18 percent lower than in the same period of 2008, primarily due to unusually high heavy oil operating costs in December 2008 due to cold weather and the resulting increase in fuel usage. Heavy oil operating costs were $16.07 per barrel for 2009 compared to $17.60 per barrel in 2008. Rock's other natural gas and light oil operations tend to have lower operating costs, which helps lower the corporate average operating cost per boe. Operating expenses are forecast to increase in 2010 to approximately $14.00 per boe primarily due to the product mix shift to heavy oil.

GENERAL AND ADMINISTRATIVE (G&A) EXPENSE

($000 except per boe)	**Year Ended 12/31/09**	Year Ended 12/31/08	Change	**Three Months Ended 12/31/09**	Three Months Ended 12/31/08	Change
Gross	**$ 4,755**	$ 4,828	(2)%	**$ 1,453**	$ 1,391	4%
Per boe (6:1)	**$ 3.79**	$ 3.84	(1)%	**$ 4.68**	$ 3.82	23%
Capitalized	**$ 1,582**	$ 1,592	(1)%	**$ 460**	$ 400	15%
Per boe (6:1)	**$ 1.26**	$ 1.27	(1)%	**$ 1.48**	$ 1.10	35%
Net	**$ 3,173**	$ 3,236	(2)%	**$ 993**	$ 991	0%
Per boe (6:1)	**$ 2.53**	$ 2.57	(2)%	**$ 3.20**	$ 2.72	18%

On an absolute dollar and per boe basis G&A expenses for the year ended December 31, 2009 were very comparable to 2008. In the fourth quarter of 2009 G&A expenses increased on a per boe basis over the same period of 2008 due to lower production. The Company capitalizes certain G&A expenses based on personnel involved in exploration and development activities, including certain salaries and related overhead costs.

INTEREST EXPENSE

	Year Ended 12/31/09	Year Ended 12/31/08	Change	Three Months Ended 12/31/09	Three Months Ended 12/31/08	Change
Interest expense ($000)	**$ 1,034**	$ 1,565	(34)%	**$ 216**	$ 331	(35)%
Per boe	**$ 0.82**	$ 1.24	(34)%	**$ 0.70**	$ 0.91	(23)%

Interest expense is incurred on bank borrowings and decreased in 2009 from 2008 due to significantly lower interest rates. The average effective interest rate for 2009 was approximately 3.6 percent compared to 5.1 percent for 2008. For the fourth quarter of 2009 the lower interest expense was also attributable to lower debt as a result of an equity financing completed in October.

STOCK-BASED COMPENSATION EXPENSE

	Year Ended 12/31/09	Year Ended 12/31/08	Change	Three Months Ended 12/31/09	Three Months Ended 12/31/08	Change
Stock-based compensation expense ($000)	**$ 1,180**	$ 1,158	2%	**$ 205**	$ 239	(14)%
Per boe	**$ 0.94**	$ 0.92	2%	**$ 0.66**	$ 0.66	0%

Stock-based compensation costs are charges which reflect the estimated value of stock options issued to directors and employees of the Company. The value of the award is recognized as an expense over the period from the grant date to the date of vesting of the award.

DEPLETION, DEPRECIATION AND ACCRETION (DD&A) EXPENSE

($000 except per boe)	Year Ended 12/31/09	Year Ended 12/31/08	Change	Three Months Ended 12/31/09	Three Months Ended 12/31/08	Change
Depletion and depreciation expense	**$ 27,428**	$ 27,849	(2)%	**$ 6,810**	$ 7,734	(12)%
Accretion expense	**263**	260	1%	**68**	71	(4)%
DD&A	**$ 27,691**	$ 28,109	(2)%	**$ 6,878**	$ 7,805	(12)%
Per boe	**$ 22.09**	$ 22.35	(1)%	**$ 22.14**	$ 21.43	3%

DD&A expense for 2009 on an absolute basis and boe basis was comparable to 2008. Fourth-quarter 2009 depletion and depreciation was lower than in the same period of 2008 on an absolute basis due to lower production.

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, acquiring operations or adjusting future estimates of timing or amounts. Similarly, this obligation can be reduced as a result of abandonment work undertaken and reducing future obligations. For 2009, the Company increased its total estimated ARO by $2.5 million to reflect current estimates of future abandonment costs. In 2009 capital programs increased the underlying ARO by $390,000 (2008 – $491,000) and actual expenditures on abandonments were $112,000 in 2009 (2008 – $94,000).

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 2010 as the Company has estimated resource tax pools available at December 31, 2009 (after the allocation of deferred partnership income) of approximately $116.4 million as set out below:

	(millions)
CEE	$ 40.4
CDE	38.6
COGPE	10.5
UCC	20.9
Loss carry-forwards	4.4
Other	1.6
Total	$ 116.4

FUNDS FROM OPERATIONS AND NET INCOME (LOSS)

	Year Ended 12/31/09	Year Ended 12/31/08	Change	**Three Months Ended 12/31/09**	Three Months Ended 12/31/08	Change
Funds from operations ($000)	**$ 19,644**	$ 40,841	(52)%	**$ 6,150**	$ 5,520	11%
Per boe (6:1)	**$ 15.67**	$ 32.48	(52)%	**$ 19.80**	$ 15.16	31%
Per share						
Basic	**$ 0.73**	$ 1.58	(54)%	**$ 0.21**	$ 0.21	0%
Diluted	**$ 0.72**	$ 1.58	(54)%	**$ 0.20**	$ 0.21	(5)%
Cash provided by operating activities ($000)	**$ 17,946**	$ 41,590	(57)%	**$ 9,487**	$ 6,261	52%
Net income (loss) ($000)	**$ (6,274)**	$ 1,891	(432)%	**$ (556)**	$ (2,083)	(73)%
Per boe (6:1)	**$ (5.00)**	$ 1.50	(433)%	**$ (1.79)**	$ (5.72)	(69)%
Per share						
Basic	**$ (0.23)**	$ 0.07	(429)%	**$ (0.02)**	$ (0.08)	(75)%
Diluted	**$ (0.23)**	$ 0.07	(429)%	**$ (0.02)**	$ (0.08)	(75)%
Weighted average shares outstanding (000):						
Basic	**26,870**	25,885	4%	**29,186**	25,900	13%
Diluted	**27,180**	25,923	5%	**30,070**	25,900	16%

Funds from operations for the year ended December 31, 2009 decreased from the prior year due to significantly lower commodity prices. The depressed commodity prices were partially offset by lower royalties and interest expense. Funds from operations for the fourth quarter of 2009 increased by 11 percent over the prior year's period primarily due to improved crude oil prices, reduced royalty rates and lower operating costs.

The Company posted a loss of $6.3 million for the year ended December 31, 2009 due to significantly lower commodity prices. As crude oil prices increased throughout 2009, the quarterly loss decreased and was only $0.6 million for the fourth quarter of 2009. With current commodity prices, Rock anticipates generating net income in 2010.

Basic and diluted shares outstanding increased in 2009 over the 2008 periods primarily due to an equity financing completed in October 2009.

CAPITAL EXPENDITURES

($000)	**Year Ended 12/31/09**	Year Ended 12/31/08	Change	**Three Months Ended 12/31/09**	Three Months Ended 12/31/08	Change
Land	**$ 1,360**	$ 5,688	(76)%	**$ 524**	$ 887	(41)%
Seismic	**890**	1,614	(45)%	**192**	487	(61)%
Drilling and completions	**19,365**	28,347	(32)%	**10,844**	7,572	43%
Facilities	**1,002**	14,095	(93)%	**655**	(88)	(844)%
Capitalized G&A	**1,582**	1,592	(1)%	**460**	400	15%
	$ 24,199	$ 51,336	(53)%	**$ 12,675**	$ 9,260	37%
Drilling incentive credits	**(3,786)**	–	–	**(2,318)**	–	–
	$ 20,413	$ 51,336	(60)%	**$ 10,357**	$ 9,260	12%
Office equipment	**79**	78	1%	**67**	(4)	(1,750)%
Property dispositions	**–**	(1,243)	–	**–**	–	–
Total net capital expenditures	**$ 20,492**	$ 50,171	(59)%	**$ 10,424**	$ 9,254	13%

For 2009, capital expenditures were 59 percent lower than in 2008 due to reduced activity resulting from low commodity prices. In addition, Rock had significant capital expenditures in 2008 due to construction of natural gas facilities at Saxon in West Central Alberta. Net capital expenditures in the fourth quarter of 2009 were higher than in the same period of 2008. This increase was due primarily to an expanded heavy oil drilling program as eight (8.0 net) heavy oil wells were drilled in the Plains core area, as well as the acceleration of a Montney vertical test at Elmworth in December originally planned for the first quarter of 2010.

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

	2009	2008
Heavy oil	**20 (20.0 net)**	18 (18.0 net)
Dry hole	**nil**	1 (1.0 net)
Total	**20 (20.0 net)**	19 (19.0 net)

Of the 20 heavy oil wells drilled in 2009, 19 are currently on production.

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

	2009	2008
Elmworth	**3 (1.1 net)**	7 (2.1 net)
Saxon	**1 (1.0 net)**	1 (1.0 net)
Other	**nil**	6 (2.2 net)
Dry hole	**nil**	nil
Total	**4 (2.1 net)**	14 (5.3 net)

None of the four natural gas wells drilled in 2009 were brought on-stream by year-end. However, two of the four wells are currently on production.

The Company has recorded $3.8 million of drilling incentive credits for the year ended December 31, 2009. The drilling incentive credit is available for drilling activity from April 1, 2009 to March 31, 2011 and is calculated at $200 per metre drilled. The drilling incentive credit can be claimed to a maximum of 50 percent of Crown royalties payable from April 1, 2009 to March 31, 2011. The Company currently estimates that approximately $4.0 million of drilling incentive credits will be recorded during 2010 on a planned capital budget for 2010 of $41.6 million.

LIQUIDITY AND CAPITAL RESOURCES

Rock currently forecasts a 2010 capital expenditure program of $41.6 million against anticipated funds from operations of $33.0 million. The capital spending in excess of cash flow is intended to be funded through bank debt. The Company had a net debt position of $25.3 million including bank debt of $23.0 million and a negative working capital position of $2.3 million at December 31, 2009. The Company's total debt to fourth quarter 2009 annualized funds from operations ratio was 1.0:1 after applying the proceeds from the equity financing completed in October 2009. The ratio is expected to range from a high of 1.3:1 in the middle of 2010 to a low of 0.9:1 by the end of 2010. The Company will continue to monitor capital, debt and cash levels and make adjustments in order to maintain an appropriate relationship between debt and funds from operations.

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 crude oil and natural gas assets and the credit currently available is $47 million. 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 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 review for the facility is scheduled to be completed before April 30, 2010. As at March 23, 2010 approximately $27.7 million was drawn under the facility.

During the fourth quarter of 2009 Rock closed an equity financing of 4,350,000 common shares at a price of $3.50 per share for total proceeds of $15.2 million (net proceeds of $14.1 million). The net proceeds were used to reduce the Company's bank credit facilities and provide capacity for its ongoing capital expenditure program and for general corporate purposes.

SELECTED ANNUAL DATA

The following table provides selected annual information for Rock:

	Year Ended 12/31/09	Year Ended 12/31/08	Year Ended 12/31/07
Production (boe/d)	**3,435**	3,436	2,198
Crude oil and natural gas revenues ($000)	**$ 50,025**	$ 80,276	$ 36,121
Average realized price ($/boe)	**$ 39.89**	$ 63.73	$ 44.93
Royalties ($/boe)	**$ 7.29**	$ 13.59	$ 8.77
Operating expense ($/boe)	**$ 13.40**	$ 13.81	$ 12.37
Field netback ($/boe)	**$ 19.20**	$ 36.33	$ 23.79
G&A expense ($/boe)	**$ 2.53**	$ 2.57	$ 3.41
Interest expense ($/boe)	**$ 0.82**	$ 1.24	$ 1.44
Funds from operations (i) ($000)	**$ 19,644**	$ 40,841	$ 15,189
Per share – basic	**$ 0.73**	$ 1.58	$ 0.72
– diluted	**$ 0.72**	$ 1.58	$ 0.72
Net income (loss) ($000)	**$ (6,274)**	$ 1,891	$ 561
Per share – basic	**$ (0.23)**	$ 0.07	$ 0.03
– diluted	**$ (0.23)**	$ 0.07	$ 0.03
Capital expenditures	**$ 20,492**	$ 50,171	$ 53,702

	As at 12/31/09	As at 12/31/08	As at 12/31/07
Total assets ($000)	**$ 145,732**	$ 150,510	$ 130,495
Total liabilities ($000)	**$ 47,264**	$ 61,488	$ 44,301
Shareholders' equity ($000)	**$ 98,468**	$ 89,022	$ 86,194

(i) Funds from operations is calculated as cash generated from operating activities before changes in non-cash working capital and asset retirement expenditures.

SELECTED QUARTERLY DATA

The following table provides selected quarterly information for Rock:

	Three Months Ended 12/31/09	**Three Months Ended 09/30/09**	**Three Months Ended 06/30/09**	**Three Months Ended 03/31/09**	Three Months Ended 12/31/08	Three Months Ended 09/30/08	Three Months Ended 06/30/08	Three Months Ended 03/31/08
Production (boe/d)	**3,376**	**3,225**	**3,329**	**3,818**	3,959	3,526	3,454	2,798
Crude oil and natural gas revenues ($000)	**$14,597**	**$12,124**	**$11,621**	**$11,683**	$ 15,746	$ 24,432	$ 24,774	$ 15,324
Average realized price ($/boe)	**$ 47.00**	**$ 40.84**	**$ 38.37**	**$ 33.99**	$ 43.23	$ 75.27	$ 78.82	$ 60.18
Royalties ($/boe)	**$ 8.37**	**$ 7.96**	**$ 5.16**	**$ 7.61**	$ 9.24	$ 16.02	$ 16.53	$ 13.11
Operating expense ($/boe)	**$ 14.49**	**$ 14.50**	**$ 12.40**	**$ 12.33**	$ 14.99	$ 13.08	$ 14.26	$ 12.48
Field netback ($/boe)	**$ 24.14**	**$ 18.38**	**$ 20.81**	**$ 14.05**	$ 19.00	$ 46.17	$ 48.03	$ 34.59
G&A expense ($/boe)	**$ 3.20**	**$ 2.51**	**$ 2.58**	**$ 1.90**	$ 2.72	$ 2.12	$ 2.43	$ 3.11
Interest expense ($/boe)	**$ 0.70**	**$ 0.95**	**$ 0.92**	**$ 0.75**	$ 0.91	$ 1.19	$ 1.47	$ 1.52
Funds from operations ($000) [(i)]	**$ 6,150**	**$ 4,403**	**$ 5,195**	**$ 3,896**	$ 5,520	$ 13,906	$ 13,807	$ 7,608
Per share – basic	**$ 0.21**	**$ 0.17**	**$ 0.20**	**$ 0.15**	$ 0.21	$ 0.54	$ 0.53	$ 0.29
– diluted	**$ 0.20**	**$ 0.16**	**$ 0.20**	**$ 0.15**	$ 0.21	$ 0.53	$ 0.53	$ 0.29
Net income (loss) ($000)	**$ (556)**	**$ (1,712)**	**$ (1,745)**	**$ (2,261)**	$ (2,083)	$ (1,266)	$ 4,020	$ 1,220
Per share – basic	**$ (0.02)**	**$ (0.07)**	**$ (0.07)**	**$ (0.09)**	$ (0.08)	$ (0.05)	$ 0.16	$ 0.05
– diluted	**$ (0.02)**	**$ (0.07)**	**$ (0.07)**	**$ (0.09)**	$ (0.08)	$ (0.05)	$ 0.15	$ 0.05
Capital expenditures, net ($000)	**$10,424**	**$ 4,599**	**$ 2,095**	**$ 3,374**	$ 9,254	$ 18,174	$ 6,345	$ 16,398

	As at 12/31/09	**As at 09/30/09**	**As at 06/30/09**	**As at 03/31/09**	As at 12/31/08	As at 09/30/08	As at 06/30/08	As at 03/31/08
Working capital deficiency (surplus) ($000)	**$ 2,335**	**$ (2,485)**	**$ (975)**	**$ 3,083**	$ 4,447	$ 4,496	$ (2,403)	$ 7,095
Bank debt ($000)	**22,997**	**37,521**	**35,752**	**35,017**	34,175	30,407	32,931	30,838
Total net debt ($000)	**$25,332**	**$35,036**	**$34,777**	**$38,100**	$ 38,622	$ 34,903	$ 30,528	$ 37,933

(i) Funds from operations is calculated as cash generated from operating activates before changes in non-cash working capital and asset retirement expenditures.

Crude oil and natural gas production increased steadily during 2008 from a combination of the growth in the West Central Alberta core area and increased heavy oil production in the Plains core area. Thereafter, crude oil and natural gas production decreased in the first quarter of 2009 due to normal production declines as drilling activity was reduced due to low commodity prices. Production in the fourth quarter of 2009 started to increase as Rock began to execute an expanded heavy oil drilling program. Royalties per boe have decreased since 2008 and averaged approximately 18 percent in 2009 primarily due to lower commodity prices. Higher commodity prices during 2008 contributed to operating cost pressures particularly for trucking, fuel and well-servicing costs. During the first half of 2009 a focus on operating expense reductions contributed to reduced operating expenses. For the last half of 2009 operating expenses were up due to workover costs initiated by the Company as heavy oil prices continued to improve. Although G&A expenses remained relatively consistent on an absolute basis since the first quarter of 2008, per unit G&A costs varied depending upon production levels. Fourth quarter G&A expenses are typically higher due to costs associated with year-end reporting. Funds from operations decreased primarily due to changes in commodity prices particularly in 2009 and the fourth quarter of 2008. The loss decreased throughout 2009 based on an increase in heavy oil pricing and production. A goodwill write-down of $5.7 million was taken in the third quarter of 2008.

Management decided to reduce capital expenditures in the first and second quarters of 2009 primarily due to an uncertain commodity price environment. For the third and fourth quarters in 2009 capital expenditures increased as the Company initiated an expanded heavy oil program due to an improvement in heavy oil pricing and the introduction of the Alberta royalty incentive program.

RESERVES

Rock's reserves have been independently evaluated by GLJ Petroleum Consultants Ltd. (GLJ) as at December 31, 2009. This was the sixth year that GLJ evaluated the Company's reserves. The reserves as at December 31, 2009 and 2008 were 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 December 31, 2009 and December 31, 2008 on a gross interest basis (before deducting royalties and without including any royalty interest).

Rock's gross interest reserves at December 31, 2009 are 5.8 million boe of proved reserves and 10.7 million boe of proved plus probable reserves. The decline in gross interest proved reserves resulted from crude oil and natural gas production partially offset by operations (net of revisions) which added 1.2 million boe of proved reserves. Proved plus probable reserves increased primarily due to additions in natural gas reserves. A total of 1.8 million boe of proved plus probable reserves were added. Proved producing reserves decreased to 42 percent of proved plus probable reserves on a gross interest basis at December 31, 2009 from 46 percent at December 31, 2008. The breakdown of reserves on a commodity basis changed slightly on a proved plus probable basis from 2008 to 2009 with heavy oil now comprising 44 percent of reserves (down from 46 percent at year-end 2008) and natural gas comprising 47 percent of reserves (up from 45 percent at year-end 2008).

Reserves Reconciliation

The following table is a reconciliation of Rock's gross interest reserves at December 31, 2009 and December 31, 2008 using GLJ's forecast pricing and cost estimates as at December 31, 2009 and December 31, 2008.

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

	Heavy Oil		Light and Medium Oil		Natural Gas Liquids		Natural Gas		Total Oil Equivalent	
	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	2,275	3,764	383	572	207	360	14,717	27,677	5,318	9,309
Additions (i)	1,000	1,741	–	–	48	67	2,487	3,589	1,462	2,406
Technical revisions (ii)	(186)	(346)	(28)	(115)	227	230	2,067	(8)	359	(231)
Dispositions	–	–	–	–	(2)	(2)	(309)	(418)	(53)	(72)
Production	(486)	(486)	(71)	(71)	(88)	(88)	(3,667)	(3,667)	(1,258)	(1,258)
December 31, 2008	2,603	4,673	283	386	392	567	15,295	27,173	5,828	10,154
Additions (i)	948	693	–	–	4	167	263	6,452	996	1,936
Technical revisions (ii)	(111)	(160)	10	(17)	44	33	1,479	(115)	188	(163)
Production	(545)	(545)	(49)	(49)	(79)	(79)	(3,487)	(3,487)	(1,254)	(1,254)
December 31, 2009	**2,895**	**4,661**	**244**	**320**	**361**	**688**	**13,550**	**30,023**	**5,758**	**10,673**

(i) Additions include discoveries, extensions, infill drilling and improved recovery.
(ii) Technical revisions include technical revisions and economic factors.
Note: mbbls = 1,000 bbls; 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 reserve volumes along with the value of future net revenue utilizing GLJ's forecast pricing and cost estimates as at December 31, 2009.

Reserves

	Heavy Oil (mbbls)	Light and Medium Oil (mbbls)	Naural Gas Liquids (mbbls)	Natural Gas (mmcf)	Total Oil Equivalent (mboe)
Proved					
Proved producing	2,127	223	290	10,977	4,470
Proved non-producing	70	21	29	1,325	341
Proved undeveloped	698	–	42	1,248	947
Total proved	2,895	244	361	13,550	5,758
Probable	1,766	76	327	16,473	4,915
Total proved plus probable	**4,661**	**320**	**688**	**30,023**	**10,673**

Net Present Value of Future Net Revenue

	Before Income Taxes (discounted at % per year)					After Income Taxes (discounted at % per year)				
($000)	0	5	10	15	20	0	5	10	15	20
Proved reserves										
Proved producing	131,779	113,409	100,160	90,237	82,507	127,281	110,325	97,947	88,595	81,258
Proved non-producing	7,524	5,480	4,243	3,415	2,825	5,709	4,117	3,180	2,563	2,127
Proved undeveloped	21,516	17,818	15,086	12,996	11,350	16,118	13,217	11,110	9,521	8,284
Total proved reserves	160,819	136,707	119,489	106,648	96,682	149,108	127,659	112,237	100,679	91,669
Probable reserves	140,092	96,457	71,358	55,313	44,281	105,014	71,392	52,092	39,771	31,317
Total proved plus probable reserves	**300,911**	**233,164**	**190,847**	**161,961**	**140,963**	**254,122**	**199,051**	**164,329**	**140,450**	**122,986**

Pricing Assumptions

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

Summary of Pricing and Cost Rate Assumptions at December 31, 2009 – Forecast Prices and Costs

	Crude Oil				Natural Gas Liquids				Natural Gas		
Year	W.T.I. Cushing, Oklahoma (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 Spot ($/mcf)	Cdn$/US$ Exchange Rate	Inflation Rate (%/year)
2010	80.00	83.26	76.60	64.99	52.46	64.11	84.93	20.02	5.96	0.950	2.0
2011	83.00	86.42	78.64	65.24	54.45	66.54	88.15	22.88	6.79	0.950	2.0
2012	86.00	89.58	80.62	65.33	56.43	68.98	91.37	23.24	6.89	0.950	2.0
2013	89.00	92.74	82.54	65.26	58.42	71.41	94.59	23.43	6.95	0.950	2.0
2014	92.00	95.90	85.35	67.52	60.42	73.84	97.82	23.79	7.05	0.950	2.0
2015	93.84	97.84	87.07	68.90	61.64	75.33	99.79	24.15	7.16	0.950	2.0
2016	95.72	99.81	88.83	70.32	62.88	76.85	101.81	25.06	7.42	0.950	2.0
2017	97.64	101.83	90.63	71.76	64.15	78.41	103.86	26.88	7.95	0.950	2.0
2018	99.59	103.88	92.46	73.22	65.45	79.99	105.96	28.84	8.52	0.950	2.0
2019	101.58	105.98	94.32	74.72	66.77	81.60	108.10	29.46	8.69	0.950	2.0
2020+ (escalating at)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	0.950	2.0

Finding, Development and Acquisition Costs

The following table summarizes Rock's finding, development and acquisition (FD&A) costs for the years ended December 31, 2009, 2008 and 2007, including future development costs.

($000 except reserve additions and per unit amounts as indicated)	**Year Ended 12/31/09**	Year Ended 12/31/08	Year Ended 12/31/07	Three-Year Cumulative
Oil and Natural Gas Operations (excluding revisions):				
Proved finding and development costs				
Capital expenditures [i]	**$ 20,413**	$ 50,939	$ 24,163	$ 95,515
Change in future development costs	**2,923**	(2,948)	3,501	3,476
Total capital	**23,336**	47,991	27,664	98,991
Reserve additions (mboe)	**995**	1,462	949	3,406
Proved finding and development costs ($/boe)	**$ 23.45**	$ 32.82	$ 29.15	$ 29.06
Proved plus probable finding and development costs				
Capital expenditures [i]	**$ 20,413**	$ 50,939	$ 24,163	$ 95,515
Change in future development costs	**7,340**	3,106	3,930	14,376
Total capital	**27,753**	54,045	$ 28,093	$ 109,891
Reserve additions (mboe)	**1,936**	2,406	1,506	5,848
Proved plus probable finding and development costs ($/boe)	**$ 14.34**	$ 22.46	$ 18.66	$ 18.79
Acquisitions/Dispositions:				
Proved finding and development costs – acquisitions (dispositions)				
Capital expenditures [i]	–	$ (1,190)	$ 28,524	$ 27,334
Change in future development costs	–	(17)	4,136	4,119
Total capital	–	(1,207)	32,660	31,453
Reserve additions (mboe)	–	(53)	971	918
Proved finding and development costs ($/boe)	–	$ 22.59	$ 33.64	$ 34.26
Proved plus probable finding and development costs – acquisitions and (dispositions)				
Capital expenditures [i]	–	$ (1,190)	$ 28,524	$ 27,334
Change in future development costs	–	(17)	11,417	11,400
Total capital	–	(1,207)	39,941	38,734
Reserve additions (mboe)	–	(72)	1,898	1,826
Proved plus probable finding and development costs ($/boe)	–	$ 16.69	$ 21.05	$ 21.21
Total Activities (including revisions):				
Proved finding and development costs				
Capital expenditures [i]	**$ 20,413**	$ 49,750	$ 52,687	$ 122,850
Change in future development costs	**2,923**	(2,965)	7,637	7,595
Total capital	**23,336**	46,785	60,324	130,445
Reserve additions (mboe)	**1,185**	1,768	1,643	4,596
Total proved finding and development costs ($/boe)	**$ 19.70**	$ 26.46	$ 36.72	$ 28.38
Proved plus probable finding and development costs				
Capital expenditures [i]	**$ 20,413**	$ 49,750	$ 52,687	$ 122,850
Change in future development costs	**7,340**	3,089	15,347	25,776
Total capital	**27,753**	52,839	68,034	148,626
Reserve additions (mboe)	**1,772**	2,103	2,786	6,661
Total proved plus probable finding and development costs ($/boe)	**$ 15.66**	$ 25.13	$ 24.42	$ 22.31

[i] Capital expenditures include capitalized G&A which has been allocated between oil and natural gas operations and acquisitions, and excludes administrative capital expenditures.

FD&A costs for oil and natural gas operations are broken down according to crude oil and natural gas operations, acquisitions and dispositions, and total activities. Crude 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 decreased to $15.66 per boe in 2009 from $25.13 per boe in 2008 and $24.42 in 2007. In 2009, Rock spent capital on initiatives in the lower cost Plains core area. In 2008, capital spending in the West Central core area included $14 million for infrastructure spending at Saxon and Musreau/Kakwa.

Of the 20 (20.0 net) heavy oil wells drilled in 2009, 19 (19.0 net) have reserves assigned at year-end.

LAND HOLDINGS

The following table summarizes Rock's land holdings as at December 31, 2009 and 2008:

(acres)		**December 31, 2009**	December 31, 2008	Change
Undeveloped	– Gross	**135,363**	135,573	–
	– Net	**84,680**	80,574	5%
Developed	– Gross	**82,851**	81,091	2%
	– Net	**32,414**	30,739	5%
Total	– Gross	**218,214**	216,664	1%
	– Net	**117,094**	111,313	5%

NET ASSET VALUE

The following table summarizes Rock's net asset value and net asset value per share as at December 31, 2009 and 2008:

($000 except number of shares and net asset value per share)	**December 31, 2009**	December 31, 2008	Change
Proved plus probable reserves (i)	**190,847**	177,466	7%
Undeveloped land (ii)	**16,936**	15,425	9%
Working capital including debt	**(25,332)**	(38,622)	(34)%
Net asset value	**182,451**	154,269	17%
Year-end shares outstanding (000)	**30,557**	25,900	18%
Net asset value per share	**$ 5.97**	$ 5.96	–
Option proceeds	**1,688**	5,390	(69)%
Net asset value	**184,139**	159,659	14%
Fully diluted shares outstanding (000)	**32,149**	27,644	16%
Net asset value per share (fully diluted)	**$ 5.73**	$ 5.78	(1)%

(i) Proved plus probable reserves value is based on the net present value of future net revenue from gross reserves using GLJ's January 2009 and 2008 forecast pricing and cost estimates and using a discount rate of 10 percent. Net present value of future net revenue does not represent fair market value.

(ii) Undeveloped land value is based on management's estimation of fair market value.

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 leased premises.

Obligations with a fixed term are as follows:

($000)	**2010**	2011	2012
Office lease premises	**$ 523**	$ 523	$ 349
Processing agreements	**$ 288**	$ 230	$ 159

OUTSTANDING SHARE DATA

At December 31, 2009 Rock had 30,557,243 common shares outstanding and 1,592,248 stock options outstanding with an average exercise price of $1.06. At March 23, 2010 Rock has 30,557,243 common shares outstanding and 1,718,881 options to purchase common shares 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 periods 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 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 controls 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 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 controls over financial reporting that occurred during the period beginning on January 1, 2009 and ended on December 31, 2009 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls 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 is possible that the disclosure and internal controls and procedures will not prevent all errors or fraud.

CHANGE IN ACCOUNTING POLICIES

Goodwill and Intangible Assets

As of January 1, 2009 the Company adopted new standards for Goodwill and Intangible Assets which establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. The effects of the new standards concerning goodwill are unchanged from the previous standard, resulting in no impact to the consolidated financial statements of the Company.

Financial Instruments

In May 2009, new standards for "Financial Instruments – Disclosures," include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments outline a hierarchy of methods used to determine the fair value of financial instruments at the balance sheet date. Level 1 inputs are based on quoted prices in active markets that can be accessed at the measurement date. Level 2 inputs are based on quoted prices in the markets that are not active or based on prices that are observable for the asset or liability. Level 3 inputs are based on unobservable inputs for the asset or liability. These additional disclosures are effective December 31, 2009 and did not impact the consolidated financial statements of the Company.

NEW ACCOUNTING PRONOUNCEMENTS

Business Combinations

In January 2009, new standards for Business Combinations apply 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. Early adoption is permitted. This standard harmonizes the Canadian standards with International Financial Report Standards (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.

International Financial Reporting Standards (IFRS)

In February 2008, the Canadian Institute of Chartered Accountants' (CICA) Accounting Standards Board (AcSB) confirmed that changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises' interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011 including comparatives for 2010. This changeover to IFRS represents a change due to new accounting standards. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Company's reported financial position and results of operations.

The Company has created a high-level plan to execute and complete this conversion project that included the completion of a preliminary assessment of the significant differences between Canadian GAAP and IFRS. This assessment highlighted areas of difference that may impact the Company. Differences have been categorized as significant, moderate or low priority items. Significant priority items have fundamental differences between IFRS and Canadian GAAP and will require detailed analysis to facilitate policy decisions and may involve measurement differences or a combination of measurement and disclosure differences.

The Company is now in the second phase of the project that is focusing on significant items that result in measurement differences. The Company is gathering data and analyzing the impact of these significant items. This detailed analysis will assess the impact of the significant differences to the Company and identify options available where choices in accounting policies are available. This analysis includes quantifying the effect on the Company's consolidated financial statements while considering impact on all external reporting including commonly reported ratios, covenants and investor and analyst information. Policy selection documentation will include the impacts the decision will have on internal processes and controls, system requirements, external disclosure requirements and a plan for implementation.

The Company considers the following to be the key areas that may impact the consolidated financial statements;

(A) Transition Decisions

IFRS 1 "First Time Adoption of IFRS" provides certain optional exemptions for entities adopting IFRS for the first time.

IFRS 1 contains an exemptions whereby a Company may choose to apply IFRS to Property, Plant and Equipment prospectively to its full cost pool provided a ceiling test under IFRS standards, be conducted at the transition date. More specifically, a Company may choose to allocate the historical full cost pool to cost centers by utilizing either volume or values from current reserves at the transition date.

As part of the aforementioned exemption, IFRS 1 also allows the prospective adoption of the standards relating to the asset retirement obligation (ARO). The ARO liability is recalculated at January 1, 2010 using the IFRS methodology and any adjustments would be offset to opening retained earnings.

(B) Property, Plant and Equipment and Impairment of Assets

The Company believes there are differences in this area between IFRS and Canadian GAAP that may significantly impact the Company. Differences include items that may be expensed or capitalized, number of depletable bases, accounting treatment for disposition of assets, levels at which ceiling tests are performed and differences in detailed ceiling test calculations. The Company is currently analyzing and quantifying these differences and has not assessed the impact on the consolidated financial statements.

(C) ARO Liability

There may also be significant differences in the calculation of the ARO liability between IFRS and Canadian GAAP. The Company is in the process of evaluating the methodology by which its ARO liability will be calculated including the appropriate discount rate to use.

(D) Disclosure Requirements

Increased disclosure requirements are also necessary for IFRS. As each significant item is analyzed, disclosure requirements will be documented to ensure required information is available.

Staff training programs began in 2009 and will be ongoing as the project unfolds. The Company will also continue to monitor standards development and regulatory pronouncements which may affect the timing, nature or disclosure of its adoption of IFRS. Additional disclosures of the key elements of the transition plan and progress of the project will be provided as information becomes available.

Due to the impact of various accounting policy alternatives and anticipated changes to IFRS prior to the conversion date, Rock has not been able to fully assess the impact of IFRS conversion on its consolidated financial statements.

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:

Crude Oil and Natural Gas Accounting – Reserves Recognition – Rock retained independent petroleum engineering consultants GLJ Petroleum Consultants Ltd. to evaluate its crude oil and natural gas reserves, prepare an evaluation report as at year-end, and report to the Company's Reserves Committee. The process of estimating crude 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 crude oil and natural gas prices and costs change. Reserves can be classified as proved, probable or possible with decreasing probabilities that the reserves will be ultimately produced.

Crude 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 crude 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 crude 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 crude 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 ARO 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 interest 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 industry. These risks can be categorized as operational, financial and regulatory.

Operational risks include generating, finding and developing, and acquiring crude 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 out-sources 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 out-sourced the marketing and certain engineering and administrative functions. Rock attempts to acquire existing crude 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 U.S./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 for funding 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.

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 began in 2008 and continued throughout 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 deteriorate and stock markets to decline substantially. However, in the latter part of 2009 and into 2010 these concerns started to moderate. These factors have negatively impacted valuations of many companies, including Rock, 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 economies worldwide, OPEC actions, excess North American natural gas supplies, and the ongoing credit and liquidity concerns. Volatile crude 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 crude 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, the Company's ability to access 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.

ENVIRONMENTAL REGULATION AND RISK

Many phases of the oil and 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. 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. 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, which calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 emission levels by 2012. In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives met in Copenhagen from December 16-18, 2009 (the "Copenhagen Conference") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty and has not been endorsed by all participating countries. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80 percent by 2050, the Copenhagen Accord does not establish binding emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada recently indicated that it will seek to achieve a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016. The federal government has introduced legislation aimed at reducing greenhouse gas emissions using an 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 Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company.

The Government of Alberta enacted the Climate Change and Emissions Management Act on July 1, 2007, amending it through the Climate Change and Emissions Management Amendment Act, which received royal assent on November 4, 2008. This act is based on an emissions intensity approach, similarly to the Government of Canada's plan, and aims for a 50 percent reduction from 1990 emissions intensity by 2020. Alberta facilities emitting more than 100,000 tonnes of carbon dioxide-equivalent greenhouse gases per year must reduce their emissions intensity by 12 percent. Industries have three options in order to meet the reduction requirements outlined in the act: (a) making improvements to operations that result in reductions; (b) 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) 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. The Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and strengthens energy standards for a number of energy-using products.

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 other things: (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, crude 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 emissions 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 additional 2 percent per year in subsequent years for existing facilities; (ii) new facilities built between 2004 and 2011 will have mandatory emissions standards based upon clean fuel standards (natural 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. For the upstream crude 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 $C0_2$.

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 Rock'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.