THE STABILITY OF HEAVY OIL

THE HIGH POTENTIAL OF UNCONVENTIONAL NATURAL GAS

2009 ANNUAL REPORT

rockenergy

Annual General Meeting

Rock Energy Inc.'s Annual General Meeting of Shareholders will be held at The Metropolitan Conference Centre, 333 – 4th Avenue S.W., Calgary, Alberta in the Tivoli/Strand Room on Tuesday, May 11th, 2010 at 2:30 p.m. M.D.T. All shareholders are invited to attend. Those unable to do so are requested to sign and return the form of proxy mailed with this report to ensure representation at the meeting.

WHY CHOOSE ONE OR THE OTHER,

WHEN YOU CAN HAVE BOTH

Rock Energy Inc. (TSX:RE) offers a unique opportunity to invest in the energy sector and gain exposure to a solid crude oil platform and an emerging natural gas resource play. We have established heavy oil operations in our Plains core area where we are levering the narrow heavy to light oil price differentials and are focused on increasing the recovery factor from a known resource base. In addition, we're developing a significant natural gas resource play at Elmworth in West Central Alberta. We have an expanded drilling program planned for 2010 that will see us build our production base and prove up our resource plays.

ROCK 2009 HIGHLIGHTS

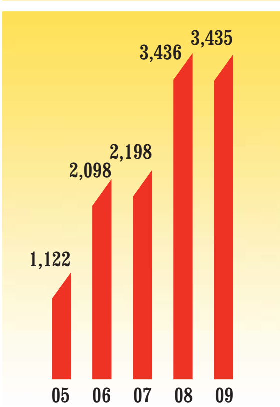
FINANCIAL

		Year Ended December 31, 2009		Year Ended December 31, 2008
Crude oil and natural gas revenue ($000)	$	**50,025**	$	80,276
Funds from operations ($000) [(1)]	$	**19,644**	$	40,841
Per share – basic	$	**0.73**	$	1.58
– diluted	$	**0.72**	$	1.58
Net income (loss) ($000)	$	**(6,274)**	$	1,891
Per share – basic	$	**(0.23)**	$	0.07
– diluted	$	**(0.23)**	$	0.07
Capital expenditures, net ($000)	$	**20,492**	$	50,171

		As at December 31, 2009		As at December 31, 2008
Working capital deficiency including bank debt ($000)	$	**25,332**	$	38,622
Common shares outstanding (000)		**30,557**		25,900
Options outstanding (000)		**1,592**		1,744

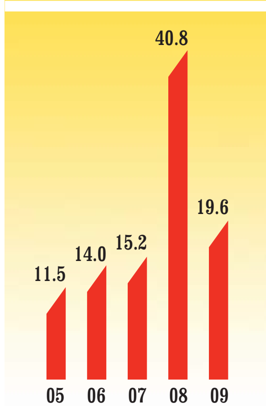
(1) Funds from operations and funds from operations per share are not terms under generally accepted accounting principles (GAAP), and represent cash generated from operating activities before changes in non-cash working capital and asset retirement expenditures. Rock considers funds from operations a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future growth through capital investment. Rock's use of 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.

PRODUCTION
(boe/d)



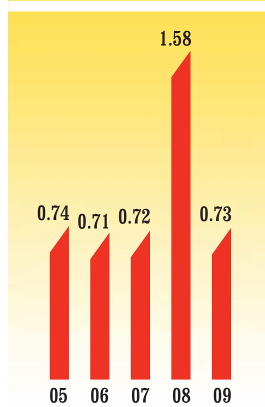
Rock maintained production in 2009 while increasing its crude oil weighting to 60 percent at year-end (from 51 percent the year before). We expect our production to reach 4,400-4,600 boe per day by December 2010 with a crude oil weighting of 70 percent.

FUNDS FROM OPERATIONS
($mm)



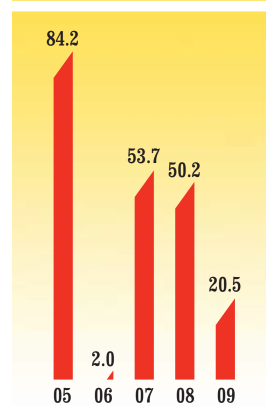
Rock's funds from operations decreased dramatically in 2009 due to lower commodity prices. The steep reduction in natural gas prices was cushioned by a narrowing heavy oil differential, mitigating the overall effect on Rock's financial results.

FUNDS FROM OPERATIONS
($/share)



Rock's funds from operations per share experienced the same effect as the absolute results.

NET CAPITAL EXPENDITURES
($mm)

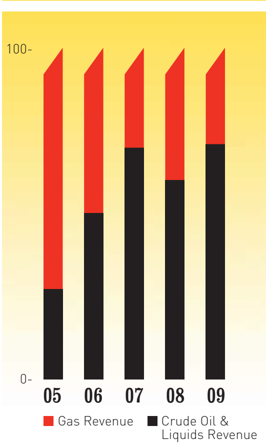


To protect the Company's balance sheet, Rock deliberately reduced capital expenditures in 2009 with a program financed primarily from internally generated cash flow.

OPERATING

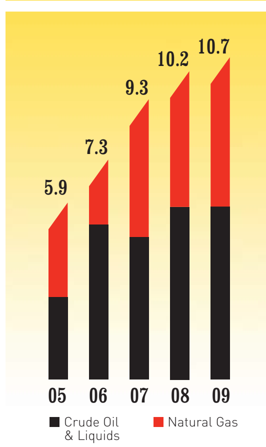
		Year Ended December 31, 2009		Year Ended December 31, 2008
Average daily production				
Crude oil and natural gas liquids (bbls/d)		**1,843**		1,761
Natural gas (mcf/d)		**9,553**		10,048
Total (boe/d)		**3,435**		3,436
Average product prices				
Crude oil and natural gas liquids (Cdn$/bbl)	**$**	**52.56**	$	74.60
Natural gas (Cdn$/bbl)	**$**	**4.20**	$	8.72
Combined (Cdn$/boe)	**$**	**39.89**	$	63.73
Field netback (Cdn$/boe)	**$**	**19.20**	$	36.33

REVENUE
BY PRODUCT TYPE
(%)



Over the last five years Rock's revenue source from crude oil has grown with increased crude oil production and prices.

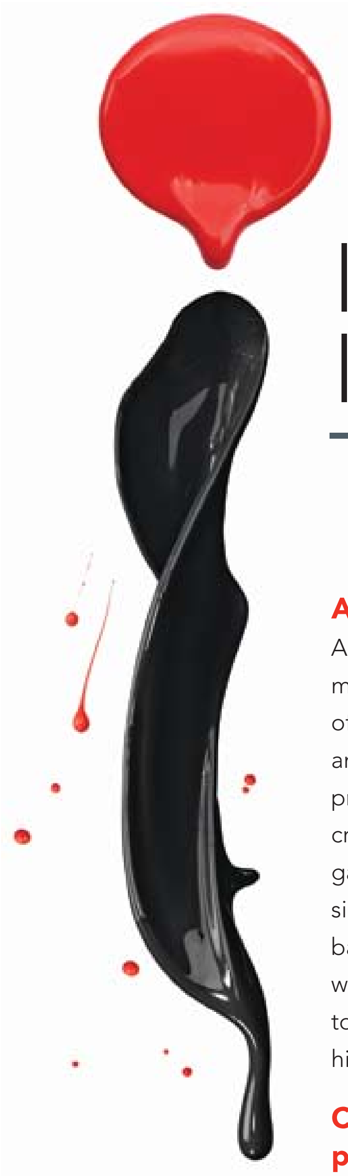
PROVED AND PROBABLE
RESERVES
(mmboe)



Rock's total reserve base was maintained year-over-year by a capital program that was comparable to cash flow. Rock's focus in 2009 was to build its drilling inventory for an aggressive capital program in 2010.

SHARE PRICE
($)

Rock's share price has enjoyed a remarkable rise over the past year from a low in March 2009 of $0.50 per share to a high of $4.70 per share in January 2010. Rock's share price growth of over 400 percent in 2009 outpaced all the indices, including the S&P/TSX and the oil and gas index, which only grew by 35 percent.



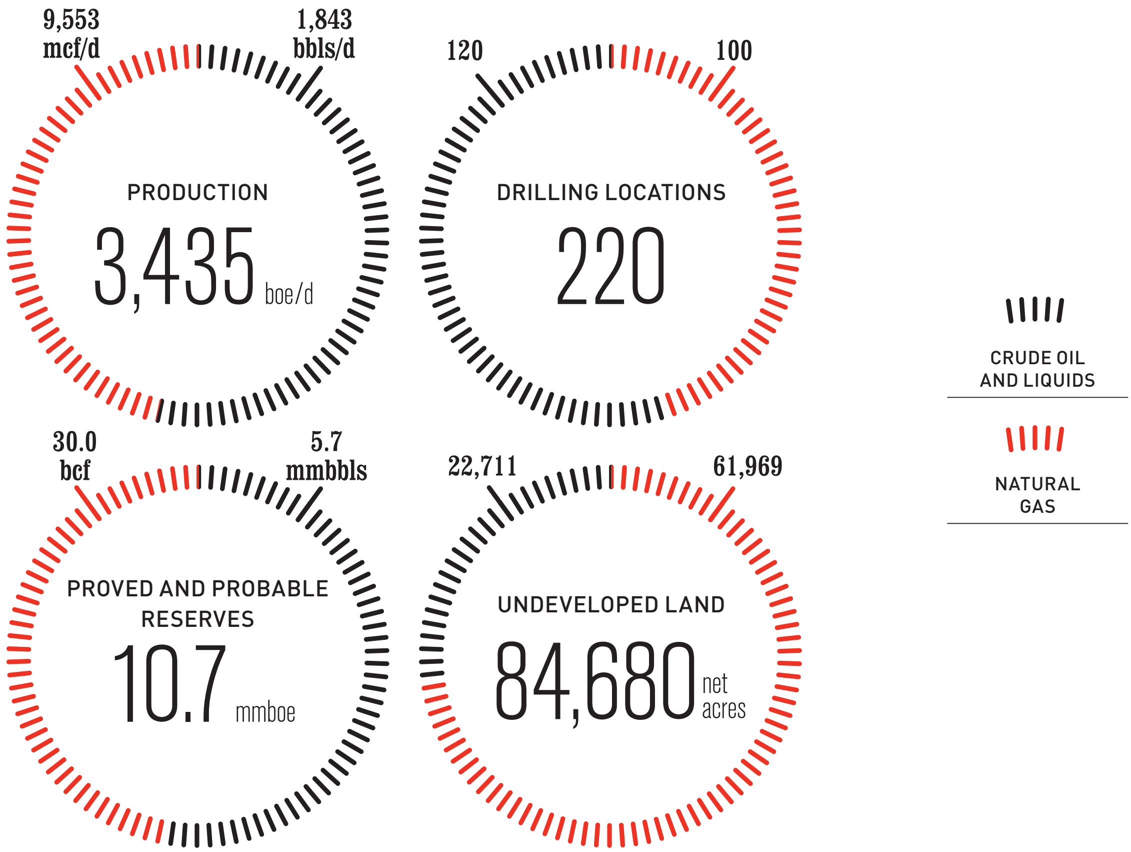
INVESTOR INSIGHT

A balanced foundation. A key principle for Rock is to maintain a balanced foundation of production, reserves, cash flow and financial capability. Our 2009 production profile was 54 percent crude oil and 46 percent natural gas, and our drilling inventory is similarly proportioned. With this balanced opportunity base Rock is well positioned to allocate capital to projects that will generate the highest returns.

Conventional heavy oil play. Rock's established heavy oil play is conventional cold flow heavy oil production on a land base that has generated current production in excess of 2,000 barrels per day and over 120 drilling locations. With strong heavy oil netbacks, the Company is able to generate solid financial results from these assets.

Deep Basin Montney and Nikanassin natural gas opportunities. The Company has assembled a significant land position in the Deep Basin Elmworth area in West Central Alberta and has commenced assessing the commercial viability of the Montney and Nikanassin natural gas plays. These opportunities will be developed using horizontal well technology completed with multiple hydraulic fractures or "multi-stage fracs". Rock has estimated that if only 10 percent of these lands generate average results, the play would triple Rock's current corporate reserve base.

Significant vertical and horizontal drilling opportunity base. During 2009, Rock doubled its drilling inventory and now has over 120 heavy oil locations and 100 vertical natural gas locations. As the new play at Elmworth is proved up, Rock expects to add a significant number of horizontal drilling locations on its 52 net sections of land.



In-house technical capability. Rock has a strong technical team experienced in both heavy oil and Deep Basin operations. For heavy oil, we are pursuing various means to achieve higher recovery factors, and for natural gas, our recent vertical test well at Elmworth established a substantial natural gas resource play from which we will apply known technologies to recover these resources.

Management track record. Rock's senior management team has a proven track record of adding value for shareholders. We have done this through a combination of grassroots exploration and development initiatives and from acquisitions.

Aggressive 2010 drilling program. During 2009 Rock was focused on maintaining production and reserves while safeguarding the balance sheet. In 2010 we are focused on growth through an aggressive capital program. A significant drilling inventory has been assembled over the last year that will lead to the drilling of 40-45 wells in 2010, almost double the number of wells drilled in 2009.

Solid balance sheet with appropriate debt levels. In the fourth quarter of 2009 Rock completed an equity financing, reducing its year-end net debt to $25.3 million, which represents 1.0 times annualized fourth quarter cash flow. With this solid balance sheet and improving commodity prices, Rock is well positioned for significant growth in 2010.

Lloydminster – Drilling rig

TO OUR SHAREHOLDERS

PRESIDENT'S LETTER

As we entered 2009, crude oil prices were in the range of US$42.00 per barrel, natural gas prices were a little over $5.00 per mcf, and the spectre of a worldwide economic recession loomed before us. At Rock we had the advantage of a balance of crude oil and natural gas production and a reasonable cash flow forecast relative to our debt position. We made a strategic decision to limit our capital expenditures to generated cash flow while working to maintain our production levels and reserve base. Our main goals for the year were to increase our drilling inventory and move our cost structure down to better position Rock to grow as the economy and commodity prices recovered.

Allen J. Bey
President and Chief Executive Officer

I am pleased to report that we achieved our 2009 goals. We doubled our drilling inventory while maintaining our production and growing our reserve base. In addition, we have made good progress in developing new completion techniques for our heavy oil wells to improve recovery factors and established a significant resource play at Elmworth that could have a material impact on the Company. We reduced our cost structure and completed an equity financing to solidify our balance sheet and reduce our debt to exit the year at 1.0 times annualized cash flow.

As we approach the second quarter of 2010 we are poised for growth. We have a solid drilling plan to increase our oil production and prove up the resource play at Elmworth. In 2010 we plan to drill 40 to 45 wells, grow our production to average 3,800-4,000 boe per day and exit the year at 4,400-4,600 boe per day while generating cash flow of $33 million ($1.08 per share), and maintaining our debt at reasonable levels.

Rock's 2009 Accomplishments

Drilling Results

In 2009, Rock participated in 24 (22.1 net) wells resulting in 20 (20.0 net) heavy oil wells and four (2.1 net) natural gas wells at 100 percent casing success rate. Rock operated 21 of the 24 gross wells. Our focus was to increase our crude oil weighting and maintain our production and reserves while spending within our cash flow.

To date in 2010 we have drilled 11 (11.0 net) heavy oil wells in the Plains core area and five (2.3 net) natural gas wells in the West Central core area.

At Elmworth, Rock's 100 percent working interest Montney vertical test well (1-19-70-9W6M) was cased in January 2010 and encountered natural gas on the up-hole Bluesky and Nikanassin zones as well as the deeper Montney zone. The Montney was completed, fracture-stimulated and tested for three days with an initial rate of 2.0 mmcf per day and a final rate of 0.9 mmcf per day at a flowing tubing pressure of 180 psi. This successful vertical test has greatly exceeded our expectations and confirmed the existence of commercial Montney natural gas on Rock's land in the Elmworth area, providing key information for future horizontal drilling locations.

The Nikanassin Formation in this well was completed and will be tied-in and on production by the end of the first quarter of 2010 and the Bluesky zone will be completed after spring break up. It's very exciting to achieve a three-zone success in our first Montney test.

An additional 100 percent working interest Saxon well (2-28-61-23W5M) was drilled in January 2010, has been cased and completed and is currently producing natural gas from the Gething Formation.

Reserves and Net Asset Value

Rock increased total Company reserves by 5 percent on a proved plus probable basis, to 10.7 million boe at year-end 2009 from 10.2 million boe at year-end 2008, replacing 141 percent of 2009 production. All-in finding, development and acquisition costs averaged $15.66 per boe on a proved plus probable basis. Rock obtained only limited recognition for the emerging Montney play at Elmworth and we expect more reserves to be confirmed as we prove up the play in 2010.

The Company's 2009 capital program was limited to cash flow for the year, which also limited near-term reserve adds. Importantly for the longer term, however, we increased our drilling inventory to more than 220 locations (from 100 a year ago). Rock's 2010 capital program is focused on converting this inventory into production and reserves growth.

The year-end 2009 reserve report by GLJ Petroleum Consultants Ltd., using its forecast commodity prices, indicates a value of $190.8 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 $5.97 per share (basic), assuming year-end net debt of $25.3 million, land of 84,680 net acres at an estimated market value of $16.9 million, no value for seismic, and 30.6 million basic shares outstanding.

Production Results

Rock's production averaged 3,435 boe per day in 2009 compared to 3,436 boe per day in 2008. In a limited capital environment, Rock was able to maintain its production levels and increase its crude oil weighting. In 2009 we increased the crude oil production component to average 54 percent and exited the year at 60 percent compared to a 2008 average crude oil component of only 51 percent. Our capital program for

2010 should see our crude oil production component increase further to exit at 70 percent.

Financial Results

In 2009 Rock generated funds from operations of $19.6 million ($0.73 per share) with a net loss of $6.3 million ($0.23 per share). The Company had capital expenditures of $20.5 million net of $3.8 million of Alberta royalty drilling credits. Total debt was $25.3 million at year-end, against bank lines of $47 million. Our borrowing base will be reviewed in April 2010.

Growth Strategy

Rock is poised for growth in 2010. In the first half of the year the Company will be building its heavy oil production base and cash flow while proving up the emerging resource play at Elmworth.

During the second half Rock intends to direct its capital to bring the natural gas projects on-stream or to further increase crude oil production, depending upon our short-term outlook for crude oil and natural gas prices. We have a strong balance sheet and cash flow base so we are also aggressively pursuing opportunities for corporate and asset acquisitions, particularly in our Plains core area.

Rock intends to grow to a production range of 10,000-15,000 boe per day within three to five years. A company of this size attracts greater market support and is better able to capture opportunities that increase shareholder value.

2010 Capital Program

Rock is planning a capital budget of $41.6 million for 2010. This will provide significant growth in our daily production while testing our Elmworth resource play, by focusing on the following:

Drill 30 heavy oil wells. These wells pay out in less than a year at current prices, and contribute significantly to the Company's cash flow.

Drill 3-4 horizontal wells at Elmworth. With a successful Montney vertical test, Rock is now proceeding with a plan for follow-up Montney and Nikanassin horizontal wells to be completed with multi-stage fracturing techniques later in the year.

Drill 10 conventional natural gas wells. These wells add to our liquids rich natural gas production at the Saxon/Kaybob area and continue to develop our vertical play concepts in our West Central Alberta core area.

Rock is forecasting production to average 3,800-4,000 boe per day in 2010, and to exit the year at 4,400-4,600 boe per day. This will represent production growth of over 25 percent. Assuming W.T.I. crude oil prices average US$75.00 per barrel and natural gas prices average Cdn$5.75 per mcf at AECO, with an average Canadian-US dollar exchange rate of $0.95, the Company will generate cash flow of $33 million ($1.08 per share) and have year-end 2010 net debt of $34 million.

Market Outlook

As we approach the second quarter of 2010 the world seems to be moving up and out of the economic recession. There are signs of recovery in many countries, and we have seen increased demand for petroleum products. As crude oil is a global commodity, and natural gas is evolving from a regional/continental commodity into a global commodity as well, Rock's realized prices are affected by world events, and we must be aware of developments around the world as we forecast our revenues and plan our capital programs. For 2010 we are much more confident than we were last year at this time, and we have increased our capital spending program accordingly. We monitor our revenues each quarter, and should significant changes occur, we will adjust our spending to maintain the Company's financial strength.

During 2009 the crude oil price started the year at US$42.00 per barrel of W.T.I. and then climbed to a peak of US$78.00 per barrel before ending the year at US$74.00 per barrel, averaging US$61.80 per barrel for the year. Today W.T.I. is around US$80.00 per barrel. The general consensus for crude oil is a range of US$70.00-US$90.00 per barrel for the next year as the world's economies begin to grow again. We agree with this consensus, and have forecast W.T.I. to average US$75.00 per barrel for the year.

Though most people tend to focus on W.T.I. prices for crude oil, what is most important for Rock is the heavy oil price as heavy oil makes up over 90 percent of our crude oil production base. A significant trend has developed over the last two years as we have witnessed a drop in the heavy to light oil differentials – the discount in price for heavy oil compared to light crude oil. Today the difference in price is below 10 percent. This change has levelled the playing field. Today one can almost say that "Heavy is the new Light"! Our vertical heavy oil wells are generating the best economic returns of any crude oil or natural gas project in Canada, with current operating netbacks of over $35.00 per barrel and historical recycle ratios of over 2.0 times.

This change in the heavy oil price dynamic is forecast to remain for the foreseeable future because there has been a significant increase in refining capacity for heavy oil in North America, which has created additional demand. Also important is the increase in pipeline capacity out of Canada to the U.S. Midwest and Gulf Coast, so that Canadian heavy crude can access these new markets. Meanwhile, competing heavy crude oil sources such as Mexico and Venezuela have experienced significant declines in capacity.

Natural gas production sold in the spot market is priced to AECO, which was Cdn$5.85 per mcf at the start of 2009, fell to a low of Cdn$2.77 per mcf and then recovered to end the year at Cdn$5.52 per mcf, while averaging Cdn$3.89 per mcf. Currently natural gas at AECO is trading in the range of Cdn$4.50 per mcf. Natural gas price forecasts can vary widely depending upon weather, economic recovery and supply assumptions.

Although we saw a significant drop in natural gas drilling activity in western Canada during the last year, we have also noted a shift toward the resource-type plays in Canada and the United States. The cost structure for natural gas is changing as we watch these new play types develop in this price environment.

Rock is currently forecasting natural gas prices to average Cdn$5.75 per mcf for 2010. Our capital program is weighted to natural gas during the second half, and if natural gas prices do not reach our forecast, we have the flexibility to shift the balance of our spending to crude oil projects. Over the longer term, Rock believes that natural gas prices will trade in the range of Cdn$5.00-$8.00 per mcf and we are developing projects that can generate attractive returns within that price range.

Our Senior Executive Team

Left to right: Allen J. Bey, President and Chief Executive Officer; Jeffrey G. Campbell, Vice President Operations and Chief Operating Officer; and John H. Van de Pol, Vice President Finance and Chief Financial Officer.

Conclusion

For 2010, we are driving a program of growth in production, reserves and cash flow. We have an exciting inventory of heavy oil projects and natural gas resource plays, plus the flexibility to allocate internal resources to achieve the best returns. We have a strong balance sheet and cash flow base, providing the funding needed to prove up our plays and achieve targeted growth without additional equity. With the strength of our Company we are also pursuing opportunities for acquisitions that can increase production and drilling locations in our core areas. I am confident that 2010 will be a year of growth for Rock.

Acknowledgements

I would like to extend my thanks and appreciation to all of our employees and directors. It is through their hard work and commitment that Rock continues to advance.

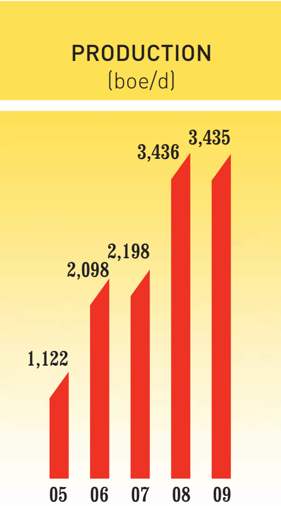
On behalf of the Board of Directors,

(signed) "Allen J. Bey"

Allen J. Bey
President and Chief Executive Officer

March 23, 2010

OPERATIONS REVIEW
AT-A-GLANCE

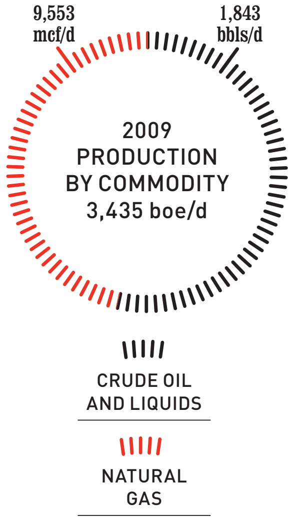


2009 Production

During 2009 Rock was able to maintain its production base. Drilling focused on heavy oil wells and Rock increased its 2009 average heavy oil production to 1,493 barrels per day from 1,329 barrels per day in 2008 and was 1,638 barrels per day during the fourth quarter of 2009. Natural gas production fell from 10.0 mmcf per day in 2008 to 9.6 mmcf per day for 2009 and 8.2 mmcf per day during the fourth quarter.

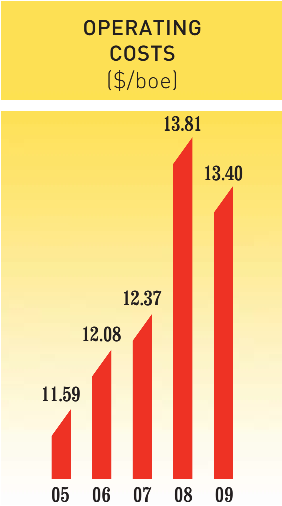
2010 Production

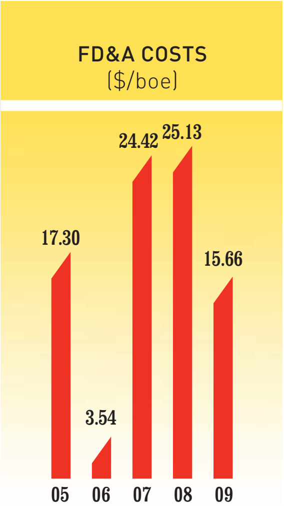
For 2010 Rock forecasts growing its production to an average of 3,800-4,000 boe per day and to reach 4,400-4,600 boe per day by year end. Rock is focused on increasing the crude oil mix to reach 70 percent by the fourth quarter of 2010.



Operating Costs

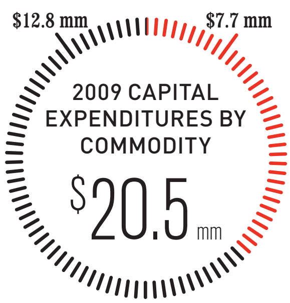
Throughout 2009, Rock has been successful in reducing operating costs to $13.40 per boe from $13.81 per boe in 2008. For 2010 we are forecasting $14.00 per boe as we have a larger component of heavy oil wells.





FD&A Costs

Rock achieved 2009 finding and development costs for proved plus probable reserves of $15.66 per boe, down significantly from $25.13 per boe in 2008. We expect further reductions in 2010 as we begin to exploit our crude oil and natural gas drilling opportunities within the Plains and West Central Alberta core areas.

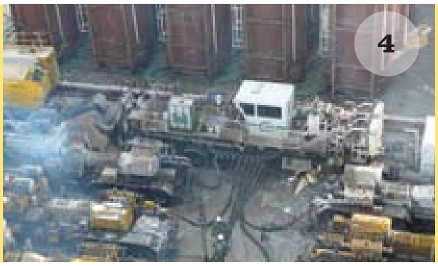


CRUDE OIL AND LIQUIDS

NATURAL GAS

Capital Expenditures

In 2009 Rock spent $20.5 million net of $3.8 million in Alberta drilling credits. The 2010 capital program has been significantly expanded to a planned net expenditure of $41.6 million. We are focused on building our production and reserve base, with 80 percent of planned spending allocated to drilling, completing and equipping wells. We have allocated 14 percent to land and seismic to continue building our drilling inventory.

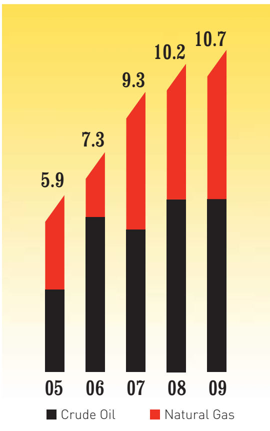


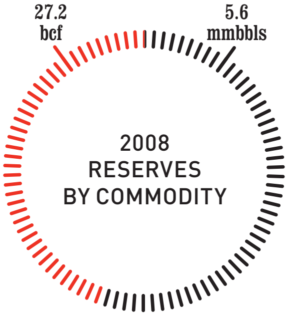
1. *Lloydminster – Drilling rig*
2. *Lloydminster – Pump to surface unit*
3. *Saxon – Compressor station*
4. *Elmworth – Well fracture stimulation*
5. *Lloydminster – Foam cleanout*

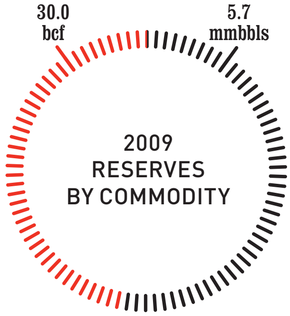
P+P Reserves

Rock grew its year-end 2009 reserves by 5 percent to 10.7 million boe. Proved reserves make up 54 percent of the total reserve base. With limited probable reserves assigned to the Montney play at Elmworth, we believe significant additional reserves will be recognized in 2010. Rock's reserve mix by commodity is balanced at 53 percent crude oil and liquids and 47 percent natural gas.

PROVED AND PROBABLE RESERVES (mmboe)







CRUDE OIL AND LIQUIDS

NATURAL GAS

HEAVY OIL

Changing Economics Favour Heavy Oil

At present, a vertical heavy oil well in the Lloydminster region can generate the top economic return and require the lowest crude oil price to break even of any crude oil drilling opportunity in Canada. This is due to narrowing heavy to light oil differentials, which results in a high netback for heavy oil, relatively low finding costs and the short payout period of such projects. These factors combine to yield stellar investment opportunities. The challenge is to find more drilling locations. At Rock we have increased our heavy oil drilling inventory to more than 120 locations from 60 at this time last year.

Narrow Differentials ...Structural Change?

Heavy to light oil price differentials narrowed considerably over the last five years (see graph), moving from 35 percent ($23.89 per barrel) in 2005 to 9 percent ($5.61 per barrel) in 2009. This has essentially levelled the playing field between light and heavy crude oil. This narrower differential could be here to stay because:

- We have witnessed a significant increase in the refining capacity for heavier barrels during the last three years. Refiners in North America could see the world crude oil slate becoming heavier, on average, and began to invest the capital to accommodate this trend. They could make attractive rates of return with $10-$20 per barrel differentials. Producers could see the forecast increase in oil sands production and began to make organic investments in upgrading capacity. These actions increased the market demand for heavy oil.

- Significant investments have been made to increase pipeline take-away capacity for Canadian heavy crude into the U.S., all the way to the Gulf Coast, the Keystone pipeline being the latest example. These pipelines have opened up new markets for Canadian heavy crude producers, which have recently invested in upgrading capacity. This has reduced heavy oil producers' reliance on a single market and pipeline, particularly Chicago.

- Canadian heavy crude has historically competed with Mexican, Venezuelan and OPEC heavy crudes. Mexican crude exports have fallen as the Cantarell field experienced drastic production declines. Investment in the Venezuelan oil and gas industry has been limited due to government actions and a lot of the remaining crude produced in Venezuela has been diverted from the U.S. to Asia. OPEC has historically reduced its heavy production in times of quota reductions, and is currently constructing large refining complexes to process its heavy crude oil at home so it may export refined products. All of these developments point to a reduced supply of heavy oil for U.S. refiners.

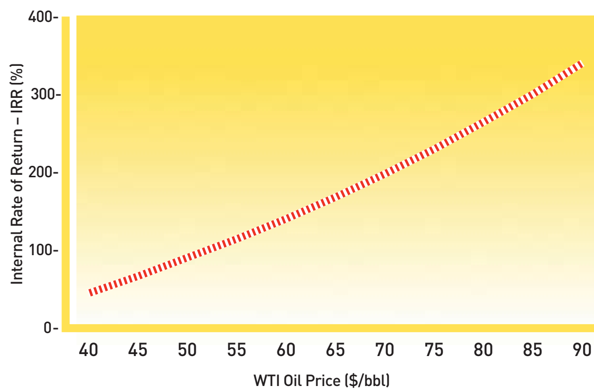
For 2010 we are forecasting a W.T.I. oil price of US$75.00 per barrel which at the forecast exchange rate would generate an Edmonton light crude price of Cdn$77.00 per barrel and a heavy oil price of Cdn$64.00 per barrel for Western Canada Select (WCS). In February 2010, WCS was trading at Cdn$77.00 per barrel and light crude oil at Edmonton was trading at Cdn$83.00 per barrel. The differential has narrowed so much in the last two years that the two crudes have become comparable. Heavy is the new light!

Robust Economics

Improved prices combined with low-cost reserve additions are generating solid economic investment opportunities. Since inception, Rock has been adding heavy oil reserves at an average cost of $12.55 per barrel. In 2009, we received an average heavy oil wellhead price of $53.31 per barrel (WCS was $58.68 per barrel), our royalty rate was 18 percent or $9.60 per barrel, and our operating costs were $16.07 per barrel, generating a netback of $27.64 per barrel for 2009 (currently over $35.00 per barrel) and a historical recycle ratio in excess of 2.0 times. When the Alberta royalty drilling credits are included the economics improve significantly.

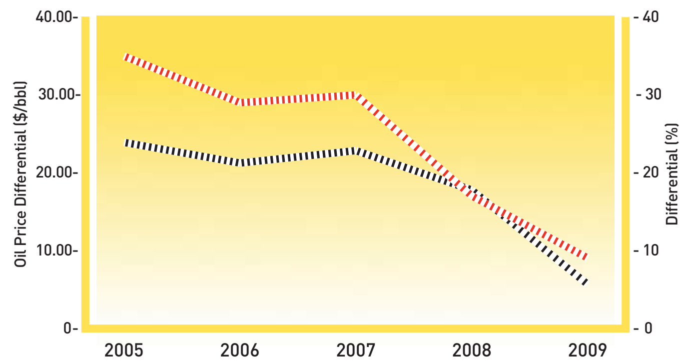
A heavy oil well pays out within one year and generates an internal rate of return in excess of 250 percent at current prices.

HEAVY OIL ECONOMICS



HEAVY OIL

HISTORICAL CRUDE OIL DIFFERENTIALS



DIFFERENTIAL % (EDMONTON LIGHT TO HARDISTY HEAVY)

DIFFERENTIAL $/BBL (EDMONTON LIGHT TO HARDISTY HEAVY)

HEAVY IS THE NEW LIGHT

ROCK HISTORICAL HEAVY OIL FD&A COST

$12.55/bbl

RECYCLE RATIO

2.2 times

HEAVY OIL

Plains Core Area: Turning an Asset into a Resource Play

In the Plains core area, Rock generally holds 100 percent working interest in its lands and operates its production. The main focus is exploring for heavy oil and shallow natural gas at depths of 500-1,000 metres. The cost to drill, complete and equip a typical heavy oil well is $500,000 to $550,000.

These wells are engaged in a cold flow production technique which encourages the production of sand concentrations of up to 30 percent during the first few months of the well's life. This creates a worm hole in the unconsolidated formation which provides a "pipeline" for the crude oil to more easily flow into the wellbore. The well is completed with large perforations and a progressive-cavity bottom hole pump. During the first few months of production, operating costs on these wells are higher than normal to accommodate the high sand production and lack of solution gas. Over time, the sand cut falls to less than 1 percent, production increases and operating costs fall. These heavy oil wells generally have an initial production rate of 30-60 barrels per day and will recover 50,000-70,000 barrels of crude oil.

In 2009 Rock spent $11.0 million to drill, complete and equip 20 (20 net) heavy oil wells. These activities increased heavy oil production to 1,638 barrels per day by the fourth quarter of 2009. For 2010, Rock is planning to drill 30 (30.0 net) heavy oil wells, with average production of 2,300-2,400 barrels per day.

Rock's focus for the year was to increase production, expand drilling inventory and improve recovery factors from known resources. Rock acquired land, processed seismic and with step-out drilling success doubled its drilling inventory from 60 to 120 locations. Most of this is on 40-acre spacing but the potential exists to down-space to 20 acres per well, thus doubling the available inventory.

Each well on 40-acre spacing discovers, on average, 1 million barrels of original-oil-in-place. With conventional production practices and the establishment of worm holes, we are only recognizing 50,000-70,000 barrels of recoverable oil per 40-acre well. This translates to a 5-7 percent recovery factor, which means we are leaving behind 93-95 percent of the crude oil. To date, we have identified up to 200 million barrels of original-oil-in-place. There is a huge resource here that requires technology to unlock that resource and transform conventional heavy oil into a resource play.

Lloydminster – Single well oil battery


ALBERTA
Lloydminster
SASKATCHEWAN
Neilburg
1 mile
R3
R2
R1W4
R28
LLOYDMINSTER
CITY OF
LLOYDMINSTER
T48
T47
T46
T45
NEILBURG
1 mile
Lloydminster
1 mile
Rock Land
Proposed Drilling Location
Vertical Producing Well
Directional Producing Well

HEAVY OIL

Plains Core Area: Technologies that Enhance Heavy Oil Recovery

Rock has embarked on a program to improve recovery factors to increase reserves and production rates. We see opportunities in three areas: drilling, completions and secondary recovery.

Drilling

This would involve down-spacing to 20 acres sooner, before worm holes are fully established, enabling a consistent pressure drainage regime. The improved sweep efficiency of additional wells into the pool would increase the recovery factor of the pool.

Second, with better cementing techniques we are expecting to improve isolation of water zones from oil zones. This will prevent premature breakthrough of water, which reduces recovery of the crude oil and increases operating costs.

Completions

Perforations

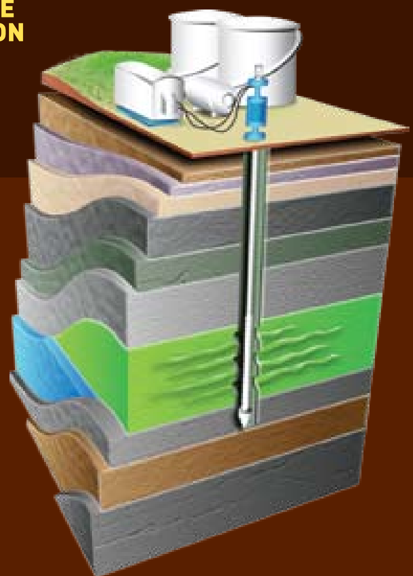
A conventional heavy oil well is perforated with a large-diameter, shallow-penetrating charge. This allows the sand to more easily flow into the wellbore and initiates the formation of a worm hole. In order to help create these worm holes and encourage more worm holes, Rock has begun to deploy a "Salt and Pepper" perforation technique which combines the large diameter perforations with smaller diameter but deeper penetrating charges. We have seen encouraging initial results from this technique.

Radial Drilling

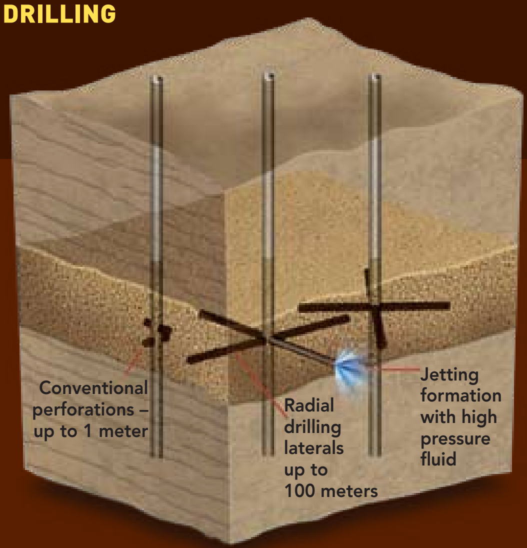
Rock has also successfully deployed a radial drilling technique to hydraulically jet a 2.5-cm-diameter horizontal leg up to 100 metres away from the wellbore in four or more directions. We expect this radial leg to act as a worm hole – but in a controlled direction. This completion technique costs $50,000-$100,000, but we expect to see at least 3-5 percent increases in recovery factors, yielding 30,000-50,000 barrels of additional reserves. Rock has used this technique on five wells in 2009 with encouraging results.

In 2010, we will continue to prove up potential reserve additions. If successful, Rock expects to be able to deploy this technology on our down-spaced wells and begin to fit worm holes between each other so that we can make significant improvements in overall pool recovery factors.

WORM HOLE PRODUCTION



RADIAL DRILLING



Foam Stimulation

Rock has successfully deployed foam stimulation on existing wells to restore and improve production levels. Surfactant foam is injected into the reservoir through the worm holes. The surfactant can act to reduce the relative viscosity of the heavy oil near the wellbore, and assists in recovering and lifting the sand and other debris from the wellbore. This treatment costs $25,000-$50,000 per well and can add 10,000-30,000 barrels of reserves. Rock has also been combining foam stimulation with radial drilling and has seen very encouraging results.

Pumps

Production practices have come a long way from the mid-1980s when we would use a standard rod pump to produce a heavy oil well with concerns about sand production seizing up the pump. Using a sand screen to protect the pump also held back the crude oil and those wells would come on at 20 barrels per day and only recover 20,000-30,000 barrels (2-3 percent recovery factor). In the mid 1990s the industry moved to progressive-cavity pumps, which accommodate sand production up to 30 percent concentrations and thus allow formation of the worm hole. We still use these pumps and today our wells produce 30-60 barrels per day and recover 50,000-70,000 barrels of reserves. In extremely high-sand situations we use a "pump to surface" unit, essentially a hydraulic cylinder that strokes the entire tubing string and allows us to produce over 30 percent sand concentrations. This "pump to surface" system helps promote the establishment of the worm hole network.

Secondary Recovery

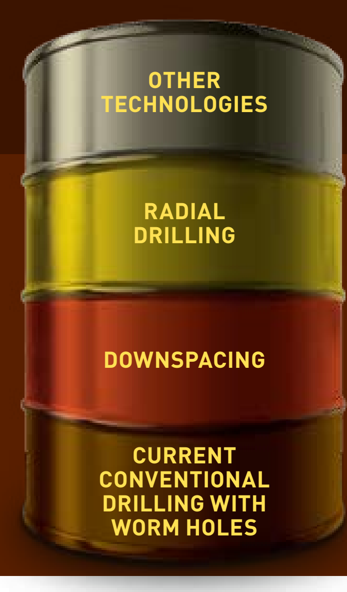
Rock's large identified resource-in-place is driving work to develop economical secondary recovery techniques. Examples include steam pulse, sonic vibration and chemical floods. These procedures are in early stages of development and Rock is reviewing its assets to continue development and potentially incorporate some of these techniques in the future.

Conclusion

We have identified a significant resource of heavy oil on our lands approaching 200 million barrels of original-oil-in-place. Using conventional production practices we can recover 5-7 percent of this resource. Rock is working on a variety of low-risk, low-cost projects to increase this recovery factor. Rock has the potential to increase the recovery factor of heavy oil turning conventional heavy oil into a resource play. The prize is very big, and the path is clearing!

FOAM STIMULATION

RECOVERY FACTORS



DEEP BASIN CONVENTIONAL AND UNCONVENTIONAL NATURAL GAS

Elmworth: An Emerging Resource Play with Substantial Upside

Deep Basin Conventional Natural Gas

In our West Central core area Rock has established an inventory of over 100 vertical conventional natural gas drilling locations. Deep Basin wells typically target the Dunvegan, Falher, Bluesky and Gething formations. Well depths range from 2,000-3,500 metres and cost $2.5-$6.0 million to drill, complete, equip and tie-in. On average these wells will have initial production rates of 1-5 mmcf per day and recover 2-5 bcf of reserves with up to 50 barrels of natural gas liquids per mmcf of raw gas. During 2009 we drilled four (2.1 net) wells in this area to earn lands in a farm-in and maintain our working interest with partners.

In 2010 we plan to drill up to 10 vertical natural gas wells as we focus on proving up plays, preserving lands, and keeping up with partners. We would increase this drilling program once we are confident in higher prices and lower costs generating solid economic returns.

Unconventional Gas

In the Elmworth area Rock has assembled over 42,000 net acres of undeveloped land over the last two years. During 2009 industry activity in this area increased significantly as the Montney and Nikanassin resource plays were extended into this area.

Nikanassin

Rock considers the Nikanassin zone as an ideal candidate for horizontal wells with multi-stage fracture completions. Rock has estimated that each section of land may hold 15-20 bcf of gas-in-place. Rock would drill three to four wells per section and is planning up to two test wells in the second half of 2010. Rock has 52 net sections of Nikanassin rights at Elmworth at an average working interest of 68 percent.

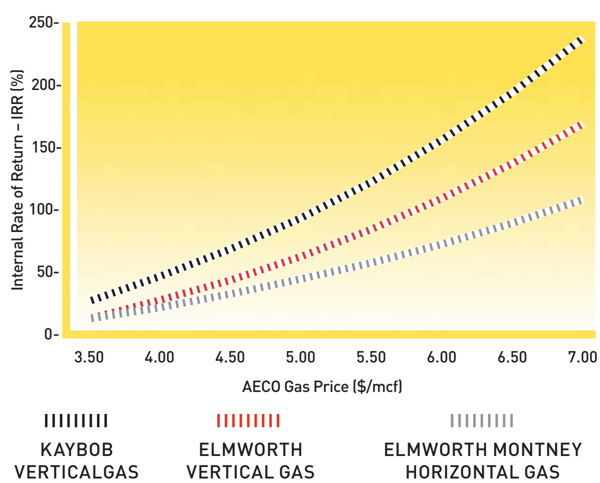
Montney

During 2009 competitors began drilling horizontal Montney wells near Rock's lands at Elmworth, where Rock holds Montney rights on 44 net sections at an average working interest of 95 percent. The Montney zone may contain original-gas-in-place of 20-25 bcf per section.

In January 2010 Rock drilled a 100 percent working interest vertical Montney test well (1-19-70-9W6M). The well encountered natural gas in the Bluesky and Nikanassin formations uphole as well as in the primary Montney target. The Montney zone was completed, fracture-stimulated and tested for three days with an initial rate of 2.0 mmcf per day and a final rate of 0.9 mmcf per day at a flowing tubing pressure of 180 psi. This test was double the rate we were hoping for and confirmed Montney gas commerciality on Rock's land at Elmworth.

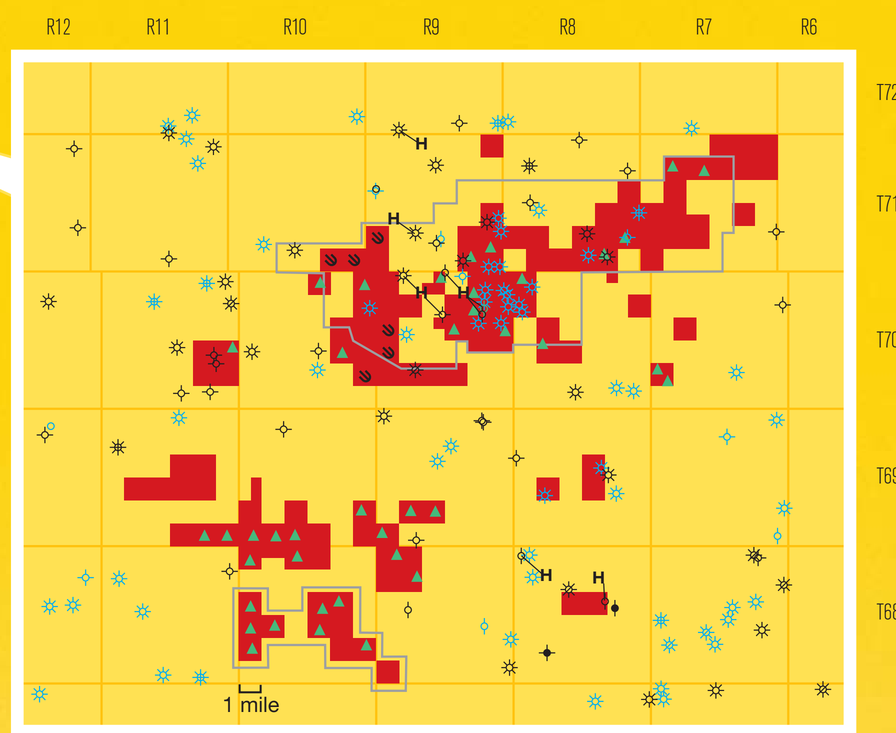
With these results Rock is planning to drill two horizontal Montney wells in the second half of 2010. This project is intended to further prove up the play and yield production in 2011. We are off to a strong start in the emerging Montney play at Elmworth.

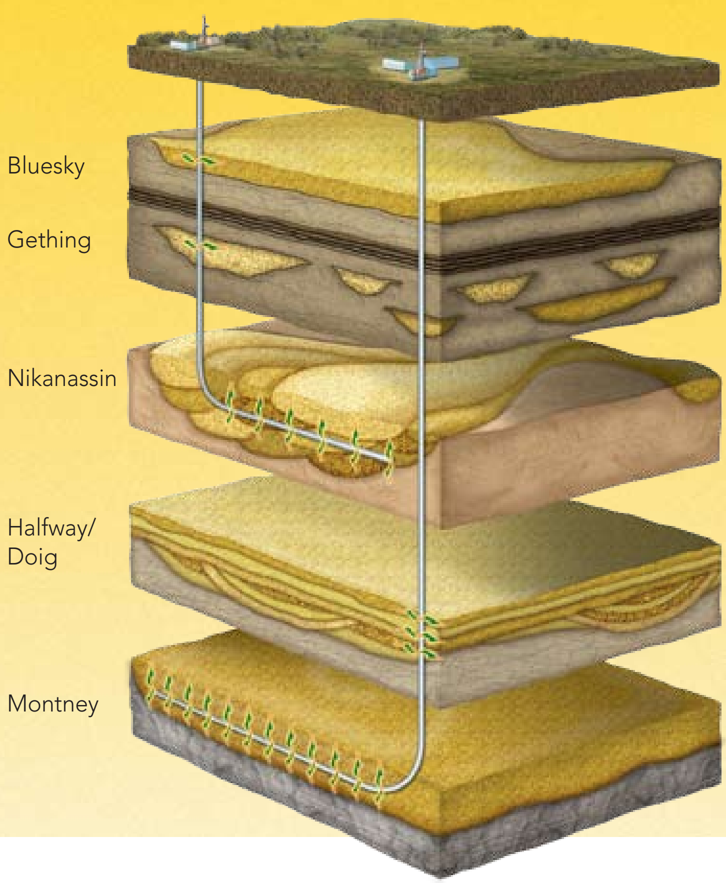
NATURAL GAS ECONOMICS




ALBERTA
Elmworth
Kakwa
Saxon

Elmworth


R12
R11
R10
R9
R8
R7
R6
T72
T71
T70
T69
T68
1 mile
Rock Active Land
Montney Penetration
Montney Horizontal Well
Proposed Montney Horizontal Location
Nikanassin Producer
Proposed Drilling Location
3D Seismic


Bluesky
Gething
Nikanassin
Halfway/ Doig
Montney

ENVIRONMENTAL, HEALTH AND SAFETY AND SOCIAL PERFORMANCE

At Rock we are committed to a stewardship program that ensures the responsible development and continuous improvement of all our business practices, in particular as they relate to Environment, Health and Safety and Social Performance. As an active member of CAPP (Canadian Association of Petroleum Producers) we are engaged in its stewardship program, which provides a framework and accountability for our actions. Our principles of operation include:

- Nothing is more important than protecting people from harm;
- Our impact on the environment should be minimized and mitigated;
- Efficient use of all natural resources is essential; and
- We work to create opportunities for economic and social benefits in the communities in which we operate.

Rock is very proud to report that we had no safety incidents in 2009. In our Calgary head office we adopted a proactive approach to maintaining the health of our employees with programs such as voluntary flu shots.

Our environmental record during the last year was excellent as we equip our facilities using best industry practices, and operate them in a proactive and responsible manner.

Although 2009 was a year of economic uncertainty, our staff and company donated generously to the communities in which we operate. In particular Rock and its employees donated over $20,000 to the 2009 United Way campaign, more than doubling the contribution that was made in 2008. This is a testimony of the generosity and social responsibility of Rock and its staff.

Saxon – Compressor station

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.

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

($000)	Before Income Taxes (discounted at % per year) 0	5	10	15	20	After Income Taxes (discounted at % per year) 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.

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 Canadian generally accepted accounting principles. 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 consolidated 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 of the Board of Directors 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.

(signed) "Allen J. Bey"

Allen J. Bey
President and Chief Executive Officer

(signed) "John H. Van de Pol"

John H. Van de Pol
Vice President, Finance and Chief Financial Officer

March 23, 2010

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Rock Energy Inc. as at December 31, 2009 and 2008 and the consolidated statements of income (loss), comprehensive income (loss) and retained earnings (deficit) 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, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(signed) "KPMG LLP"

KPMG LLP
Chartered Accountants

Calgary, Canada
March 23, 2010

Consolidated Balance Sheets

(all amounts in $000) As at	December 31, 2009	December 31, 2008
Assets		
Current Assets		
Accounts receivable	$ 10,755	$ 11,896
Prepaid expenses and deposits	1,324	908
	12,079	12,804
Property, plant and equipment (note 5)	133,653	137,706
	$ 145,732	$ 150,510
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	$ 14,414	$ 17,251
Bank debt (note 7)	22,997	34,175
	37,411	51,426
Future tax liability (note 11)	2,320	5,565
Asset retirement obligation (note 8)	7,533	4,497
Shareholders' Equity		
Share capital (note 9)	96,225	81,600
Contributed surplus (note 9)	4,553	3,458
Retained earnings (deficit)	(2,310)	3,964
	98,468	89,022
Commitments (note 12)		
	$ 145,732	$ 150,510

See accompanying notes to the consolidated financial statements.

Approved by the Board:

(signed) "James K. Wilson"

James K. Wilson
Director

(signed) "Allen J. Bey"

Allen J. Bey
Director

Consolidated Statements of Income (Loss), Comprehensive Income (Loss) and Retained Earnings (Deficit)

(all amounts in $000 except per share amounts) Years ended	**December 31, 2009**	December 31, 2008
Revenues		
Crude oil and natural gas	**$ 50,025**	$ 80,276
Royalties	**(9,140)**	(17,094)
	40,885	63,182
Expenses		
Operating	**16,795**	17,361
General and administrative	**3,173**	3,236
Interest	**1,034**	1,565
Stock-based compensation (note 10)	**1,180**	1,158
Goodwill impairment (note 5)	**–**	5,748
Depletion, depreciation and accretion	**27,691**	28,109
	49,873	57,177
Income (loss) before income taxes	**(8,988)**	6,005
Taxes		
Provincial capital taxes	**239**	179
Future income taxes (reduction) (note 11)	**(2,953)**	3,935
Net income (loss) and comprehensive income (loss)	**(6,274)**	1,891
Retained earnings, beginning of year	**3,964**	2,073
Retained earnings (deficit), end of year	**$ (2,310)**	$ 3,964
Basic and diluted net income (loss) per share (note 9)	**$ (0.23)**	$ 0.07

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(all amounts in $000) Years ended	December 31, 2009	December 31, 2008
Cash provided by (used in):		
Operating:		
Net income (loss) for the year	$ (6,274)	$ 1,891
Add (less) non-cash items:		
Depletion, depreciation and accretion	27,691	28,109
Goodwill impairment	–	5,748
Stock-based compensation	1,180	1,158
Future income taxes (reduction)	(2,953)	3,935
Asset retirement expenditures	(112)	(94)
	19,532	40,747
Changes in non-cash working capital	(1,586)	843
	17,946	41,590
Financing:		
Issuance of common shares	14,329	81
Repurchase of stock options	(79)	(205)
Increase (decrease) in bank debt	(11,178)	6,770
	3,072	6,646
Investing:		
Property, plant and equipment	(20,492)	(51,414)
Disposition of property, plant and equipment	–	1,243
Changes in non-cash working capital	(526)	1,935
	(21,018)	(48,236)
Change in cash	–	–
Cash, at beginning and end of year	$ –	$ –
Interest and cash taxes paid and received:		
Interest paid	$ 1,006	$ 1,465
Cash taxes paid	$ –	$ –

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

For the years ended December 31, 2009 and 2008 (all amounts in text and tables are in $000 except per share amounts, numbers of shares and options, and other exceptions as indicated).

1. Nature of Operations

Rock Energy Inc. (the "Company" or "Rock") is actively engaged in the exploration, development and production of crude 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) Joint Operations

A substantial portion of the Company's crude 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.

(C) Property, Plant and Equipment

The Company follows the full cost method of accounting for its crude 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 crude 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.

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. Crude oil and natural gas liquids reserves and production are converted into equivalent units of natural gas based on relative energy content. 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.

Office furniture and equipment are recorded at cost and depreciated on a declining balance basis using an annual rate of 20 percent.

Rock calculates its ceiling test by comparing the carrying amount of crude 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.

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 a crude oil or 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.

(D) 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.

(E) 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.

(F) 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 vesting period 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.

(G) Revenue Recognition

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

(H) 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 are based on estimates of crude oil and natural gas 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.

(I) 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. Changes in Accounting Policies

(A) Goodwill and Intangible Assets

As at 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.

(B) 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.

4. Pending Accounting Changes

(A) 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 Reporting 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.

5. Property, Plant and Equipment

	December 31, 2009	December 31, 2008
Petroleum and natural gas properties	$ 224,291	$ 200,994
Office equipment	1,511	1,432
	225,802	202,426
Accumulated depletion and depreciation	(92,149)	(64,720)
	$ 133,653	$ 137,706

At December 31, 2009, the depletable base for the petroleum and natural gas properties included $14,628 (December 31, 2008 – $11,704) of future development costs and excluded $17,860 (December 31, 2008 – $17,761) of unproved property costs.

During the year ended December 31, 2009, $1,582 (year ended December 31, 2008 – $1,592) of administrative costs relating to exploration and development activities were capitalized as part of property, plant and equipment.

At December 31, 2009, 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:

	Crude Oil W.T.I. (Cushing, Oklahoma) (US$/bbl)	Crude Oil Edmonton par (40° API) (Cdn$/bbl)	Natural Gas AECO-C Spot Price (Cdn$/mmbtu)	Heavy Oil at Hardisty (12° API) (Cdn$/bbl)	Currency Exchange Rate (US$/Cdn$)
2010	80.00	83.26	5.96	64.99	0.95
2011	83.00	86.42	6.79	65.24	0.95
2012	86.00	89.58	6.89	65.33	0.95
2013	89.00	92.74	6.95	65.26	0.95
2014	92.00	95.90	7.05	67.52	0.95
2015	93.84	97.84	7.16	68.90	0.95
2016	95.72	99.81	7.42	70.32	0.95
2017	97.64	101.83	7.95	71.76	0.95
2018	99.59	103.88	8.52	73.22	0.95
2019	101.58	105.98	8.69	74.72	0.95
Thereafter (escalation)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	0.95

The Company does not have any impairment related to its property, plant and equipment for the year ended December 31, 2009 and 2008.

Goodwill of $5,748 was written off due to the application of a market-based impairment test as at September 30, 2008.

6. Risk Management and Financial Instruments

(A) 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, 2009 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 $353 change ($352 for 2008) in net income for 2009. 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 $531 change ($500 for 2008) in net income for 2009.

(B) 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, 2009 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 $368 ($535 for 2008) change to net income for 2009.

(C) Credit Risk:

Substantially all of the Company's 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, joint interest partners and oil and natural gas marketers 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 whenever possible. Further risk exists with joint interest partners as disagreements occasionally arise and may increase the potential for non-collection. Currently, there is no indication that amounts are non-collectable; thus, an allowance has not been set up. 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 that 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, 2009 the Company's receivables consisted of $637 (December 31, 2008 – $7,966) from joint interest partners, $5,377 (December 31, 2008 – $3,397) from oil and natural gas marketers, $3,786 (December 31, 2008 – nil) of drilling incentive credits and $955 (December 31, 2008 – $533) of other trade receivables.

(D) 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.

(E) Interest Rate Risk:

The Company is exposed to interest rate risk to the extent that bank debt is at a floating short-term rate of interest. The Company does not have any financial or interest rate contracts in place as of December 31, 2009. A 1 percent change to the floating short-term interest rates is estimated to result in a $225 change ($218 for 2008) in net income for 2009.

7. Bank Debt

The Company has a demand operating credit facility with a Canadian chartered bank subject to the bank's valuation of the Company's crude oil and natural gas properties. The limit under the facility at December 31, 2009 was $47 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 amount of the facility is subject to a borrowing base test performed on a periodic basis by the lender, based primarily on reserves and using commodity prices estimated by the lender as well as other factors. A decrease in the borrowing base could result in a reduction to the credit facility. The next review for the facility is to be completed before April 30, 2010.

8. Asset Retirement Obligation (ARO)

The ARO results 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 ARO at December 31, 2009 to be approximately $12,459 (December 31, 2008 – $7,716) including expected annual inflation of 1.5 percent (December 31, 2008 – 1.5 percent). A credit-adjusted risk-free rate of 8 percent (December 31, 2008 – 8 percent) was used to calculate the fair value of the ARO. These obligations are expected to be incurred from the current year through 2028 and are expected to be funded through general corporate funds at the time of retirement.

The following table outlines a reconciliation of the ARO:

ARO	**December 31, 2009**	December 31, 2008
Opening balance	**$ 4,497**	$ 3,840
Liabilities incurred	**390**	549
Accretion	**262**	260
Revisions [i]/dispositions	**2,496**	(58)
Actual retirement expenditures	**(112)**	(94)
Closing balance	**$ 7,533**	$ 4,497

(i) Revisions to the ARO are a result of changes in current estimates of future abandonment costs.

9. Share Capital and Contributed Surplus

(A) Authorized:

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

300,000 preferred shares, without stated par value, of which none have been issued.

(B) Common Shares Issued:

	Number		Amount
Issued and outstanding on December 31, 2007	25,877,642	$	81,600
Future tax effect of flow-through share renouncements	–		(98)
Issued on exercise of stock options	13,334		59
Issued for flow-through shares on exercise of stock options (i)	8,867		39
Issued and outstanding on December 31, 2008	25,899,843		81,600
Issued for flow-through shares (ii)	300,000		219
Issued on exercise of stock options	7,400		11
Issued for cash on equity financing (iii)	4,350,000		15,225
Share issue costs (net of future income taxes of $292)	–		(830)
Issued and outstanding on December 31, 2009	**30,557,243**	**$**	**96,225**

(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 a new management appointee in April 2009.

(iii) The Company completed an equity financing on October 29, 2009 of 4,350,000 common shares at $3.50 per share for gross proceeds of $15,225 (net proceeds of $14,103).

(C) Stock Options:

The Company has a stock option plan ("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 initial grant of options vests yearly in one-third tranches beginning on the first anniversary of the grant date and expires one year after vesting. Options granted to replace an expiring tranche, if applicable, vest in two years and expire in three years. The following table summarizes the stock options outstanding at December 31, 2009 and December 31, 2008 and changes during the year ended on those dates:

	Number of Options	Weighted Average Exercise Price
December 31, 2007	2,307,822	$ 3.42
Granted	444,532	2.92
Exercised (i)	(198,240)	3.26
Forfeited	(423,328)	3.28
Expired	(386,582)	4.61
December 31, 2008	1,744,204	3.09
Granted	1,615,399	1.03
Exercised (ii)	(50,985)	1.38
Forfeited	(302,676)	2.50
Cancelled (iii)	(1,367,028)	3.15
Expired	(46,666)	4.79
December 31, 2009	**1,592,248**	**$ 1.06**

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

(ii) 43,585 options were put back to the Company for the in-the-money gain.

(iii) Options were cancelled under a voluntary stock option surrender program approved by the Board of Directors. Thirty percent of the options surrendered were subsequently re-issued at market price. One-third of the re-issued options vested immediately.

Options outstanding and exercisable under the stock option plan are summarized below as at December 31, 2009:

	Outstanding Options			Exercisable Options	
Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Years to Expiry	Number of Options	Weighted Average Exercise Price
$0.84 – $0.99	**1,312,582**	**$ 0.87**	**2.18**	**36,984**	**$ 0.94**
$1.61 – $2.09	**279,666**	**$ 1.94**	**2.56**	**–**	**–**
	1,592,248	**$ 1.06**	**2.25**	**36,984**	**$ 0.94**

Contributed Surplus:

Changes in the contributed surplus account for December 31, 2009 and December 31, 2008 are outlined as follows:

	December 31, 2009	December 31, 2008
Opening balance	**$ 3,458**	$ 2,521
Stock-based compensation expense	**1,180**	1,158
Net benefit on options exercised [(i)]	**(85)**	(221)
Closing balance	**$ 4,553**	$ 3,458

(i) The benefit of options exercised for shares are recorded as a reduction of contributed surplus and an increase to share capital.

(D) Per Share Amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average number of common shares outstanding for the year ended December 31, 2009 was 26,869,880 (December 31, 2008 – 25,885, 309).

In computing the diluted per share amount, the treasury method was used. For the year ended December 31, 2009 a total of 310,467 shares (year ended December 31, 2008 – 37,714 shares) were added to the weighted average shares outstanding for the dilutive effect of employee stock options.

10. Stock-Based Compensation

Options granted to employees and non-employees are accounted for using the fair value method. The fair value of 1,615,399 common share options granted during the year ended December 31, 2009 was estimated to be $1,012. The fair value of common share options as at the grant date is determined using the Black-Scholes option pricing model with the following assumptions for options issued during the year ended December 31, 2009:

Risk-free interest rate:	2.4%	Expected volatility:	105%
Expected life:	Three-year average	Expected dividend yield:	0%

11. Income Taxes

The provision for income taxes varies from the amount that would be computed by applying the expected tax rate to income (loss) before income taxes. The principal reasons for differences between such "expected" income tax expense and the amount actually recorded are as follows:

	December 31, 2009	December 31, 2008
Income (loss) before income taxes	$ (8,988)	$ 6,005
Statutory income tax rate	29.4%	29.8%
Expected income taxes (reduction)	$ (2,642)	$ 1,789
Add (deduct):		
Stock-based compensation	347	345
Goodwill impairment	–	1,714
Change in rate	(593)	38
Change in valuation allowance	(13)	(23)
Other	(52)	72
Future income taxes (reduction)	$ (2,953)	$ 3,935

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, 2009	December 31, 2008
Loss carry-forwards	$ 1,686	$ 3,485
Property, plant and equipment	(1,702)	(60)
Deferral of partnership earnings	(4,077)	(9,810)
Share issuance costs	427	231
Asset retirement obligation	1,958	1,214
Calculated future income tax liability	(1,708)	(4,940)
Valuation allowance	(612)	(625)
Future income tax (liability)	$ (2,320)	$ (5,565)

The non-capital losses prior to the allocation of deferred partnership income expire as follows:

2014	$ 1,320
2015	1,031
2026	1,091
2027	1,000
	$ 4,442

12. Commitments

The Company has the following obligations with fixed terms:

	2010	2011	2012
Office lease premises	$ 523	$ 523	$ 349
Processing arrangements	$ 288	$ 230	$ 159

13. 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 will enable the Company to access the equity and debt markets when deemed advisable and maintain existing shareholders as well as attract new investors. 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 to be components of its capital base. The Company can access or increase capital through the issuance of shares, through bank borrowings, which are based on crude oil and natural gas reserves, and by building cash reserves by reducing its capital expenditure program.

	December 31, 2009	December 31, 2008
Shareholders' equity	**$ 98,468**	$ 89,022
Bank debt	**22,997**	34,175
Working capital deficiency (excluding bank debt)	**2,335**	4,447

The Company monitors its capital 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 cash flow from operations before changes in non-cash working capital and asset retirement expenditures from the Company's most recent quarter multiplied by four. The Company intends to manage its debt at a ratio of approximately 1.5:1 depending on the timing and nature of the Company's activities. 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 changes thereto.

At December 31, 2009 the Company's debt to annualized funds flow ratio was 1.0:1.

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, as defined, 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 was in compliance with this covenant as at December 31, 2009.

Historical Five-Year Review

Financial	2009	2008	2007	2006	2005
Funds from operations [1] ($000)	**$ 19,644**	$ 40,841	$ 15,189	$ 13,971	$ 11,477
Per boe	**$ 15.67**	$ 32.48	$ 18.93	$ 18.24	$ 28.02
Per share	**$ 0.73**	$ 1.58	$ 0.72	$ 0.71	$ 0.74
Net income ($000)	**$ (6,274)**	$ 1,891	$ 561	$ (884)	$ 1,510
Per boe	**$ (5.00)**	$ 1.50	$ 0.70	$ (1.15)	$ 3.69
Per share	**$ (0.23)**	$ 0.07	$ 0.03	$ (0.05)	$ 0.10
Realized product price ($/boe)	**$ 39.89**	$ 63.73	$ 44.93	$ 43.27	$ 55.85
Royalty expense ($/boe)	**$ 7.29**	$ 13.59	$ 8.77	$ 8.98	$ 12.28
Royalty percentage	**18.3%**	21.3%	19.5%	20.8%	22.0%
Operating expense ($/boe)	**$ 13.40**	$ 13.81	$ 12.37	$ 12.08	$ 11.59
Field netback ($/boe)	**$ 19.20**	$ 36.33	$ 23.79	$ 22.21	$ 31.98
G&A expense per ($/boe)	**$ 2.53**	$ 2.57	$ 3.41	$ 2.97	$ 3.44
Capital expenditures [2] ($000)	**$ 20,492**	$ 51,414	$ 25,575	$ 32,878	$ 23,644
Average basic shares outstanding	**26.87**	25.89	21.24	19.64	15.44

Operations	2009	2008	2007	2006	2005
Production					
Heavy oil (bbls/d)	**1,493**	1,329	1,194	792	187
Light oil (bbls/d)	**133**	193	215	179	133
Natural gas (mcf/d)	**9,553**	10,048	4,261	6,421	4,476
Natural gas liquids (bbls/d)	**217**	239	79	57	56
Total (boe/d)	**3,435**	3,436	2,198	2,098	1,122
Field Price Realizations					
Heavy oil ($/bbl)	**53.31**	71.58	41.18	38.35	27.44
Light oil ($/bbl)	**60.59**	95.86	70.69	64.46	64.95
Natural gas ($/mcf)	**4.20**	8.72	6.96	7.07	10.22
Natural gas liquids ($/bbl)	**42.42**	74.15	60.00	61.35	56.19
Boe ($/boe)	**39.89**	63.73	44.93	43.27	55.85

(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 and asset retirement expenditures. 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.

(2) Excludes acquisitions and dispositions activity.

Rock Energy Team

Front Row – left to right: Jesse Vito, Anita Gross, Al Bey, John Van de Pol, Bernie Kanwal, and Priscilla Brown.

Middle Row – left to right: May Wong, Michelle Coleman, Simonne Birrell, Jeff Campbell, Shane Cushing, Jan Rintoul, Gisella Castillo, Terry Manery, Arezki Ioughlissen, Karisha Sproule, Keith Carr, and Susan Kwan.

Back Row – left to right: Bryan Dozzi, Bob Phelps, Matt Brown, Tony Geier, and James Elliott.

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

Corporate Information

BOARD OF DIRECTORS

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Chairman of the Board
Independent Businessman

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Calgary, Alberta

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ARC Financial Corp.
Calgary, Alberta

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Morgas Ltd.
Calgary, Alberta

James K. Wilson
Vice President, Finance and
Chief Financial Officer
Grizzly Resources Ltd.
Calgary, Alberta

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Chief Operating Officer

John H. Van de Pol
Vice President, Finance and
Chief Financial Officer

Grant A. Zawalsky
Corporate Secretary

AUDITORS

KPMG LLP

BANK

National Bank of Canada

ENGINEERING CONSULTANT

GLJ Petroleum Consultants Ltd.

SOLICITORS

Burnet, Duckworth & Palmer LLP

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Stock Symbol: RE

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2009 SHARE PRICE AND VOLUME

		High		Low	Volume
First quarter	$	1.40	$	0.50	2,146,223
Second quarter	$	1.84	$	0.80	2,548,148
Third quarter	$	3.00	$	1.50	2,868,356
Fourth quarter	$	3.85	$	2.92	7,517,427
Year	**$**	**3.85**	**$**	**0.50**	**15,080,154**

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