



2008

RICHARDS OIL & GAS LIMITED MANAGEMENT DISCUSSION & ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

This management discussion and analysis of the results of operations and financial condition ("MD&A") for Richards Oil & Gas Limited (the "Company") should be read in conjunction with the Company's audited financial statements for the years ended December 31, 2008 and 2007 and the notes related thereto. All amounts are stated in Canadian dollars unless otherwise specified. This MD&A is based upon information available to, and is dated, April 7, 2009. Additional information relating to the Company can be viewed or downloaded at www.richardsoilandgas.com or on SEDAR at www.sedar.com

Throughout this MD&A, BOE, or barrel of oil equivalent, is defined as 6 Mcf to 1 bbl. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Except where noted, the financial information presented has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP").

2008 HIGHLIGHTS

- Increased average annual production volumes 35% to 201 BOE per day up from 149 BOE per day in 2007. Exit rate production also increased 25% to 213 BOE per day from 171 BOE per day in December 2007.
- The Company's total proved plus probable reserves increased by 28% to 2,308 MBOE up from 1,805 MBOE in 2007. Total proved reserves increased by 15% to 1,329 MBOE. The Company's reserve life index based on fourth quarter 2008 production levels is estimated at 12.5 years total proved and 20.6 for total proved plus probable reserves.
- Commenced natural gas production from the Company's Thorsby property in December 2008.
- The Company's 2008 drilling program recorded 100 percent success during the year with activity focused primarily on the Company's Thorsby property. In 2008 the Company drilled 13 wells (12.0 net) of which 12 wells (11.6 net) were drilled at Thorsby. The remaining non-operated well was drilled at Lacombe. All of the wells drilled in 2008 targeted the highly predictable Horseshoe Canyon coals.

SELECTED FINANCIAL INFORMATION

\$ Amount except for per share information	Year ended December 31		
	2008	2007	Change
Production revenues	3,653,752	2,102,333	74%
Net loss	(2,553,207)	(15,556,641)	(84%)
Net loss per share	(0.035)	(0.29)	(88%)
Property and equipment additions	7,090,204	9,761,919	(27%)
Total assets	25,161,592	24,964,985	1%
Total liabilities	13,099,601	10,581,701	24%
Common shares outstanding – basic	72,661,602	72,661,602	nil%
Common shares outstanding – diluted	96,648,038	97,429,336	(1%)



SELECTED OPERATIONAL INFORMATION

	Year ended December 31		
	2008	2007	Change
Natural gas (mcf/day)	1,144	818	40%
Crude oil (bbl/day)	8	12	(33%)
Total (BOE/day)	201	149	35%
Exit rate (BOE/day)	213	171	25%
Natural gas price (\$/mcf)	\$8.07	\$6.34	27%
Oil price (\$/bbl)	\$76.40	\$43.01	77%
Royalties (\$/BOE)	\$6.81	\$7.20	(5%)
Operating expenses (\$/BOE)	\$20.04	\$18.36	9%
Operating netback (\$/BOE)	\$22.88	\$13.00	76%

OPERATIONS

Oil and gas production revenues increased to \$3,653,752 in 2008 from \$2,102,333 in 2007. This increase is primarily a result of higher natural gas production and higher natural gas prices received. Natural gas production increased as a result of additional well completions and a full year of production from the Company's Morningside area. The Company did experience decrease in oil production primarily due to natural declines and the shutting in of one well in late 2007 that was no longer producing economically.

Net production for 2008 was 201 BOE per day compared with 149 BOE per day for 2007. Exit rates for the months of December 2008, and 2007, were 213 and 171 BOE per day respectively. Subsequent to the end of 2008, production rates have risen to approximately 220 BOE per day.

Current production levels are considerably lower than expected primarily as a result of operational issues experienced at the Company's Thorsby property. Production from the Company's wells that targeted the Edmonton sand intervals have formation water entering the wellbores and therefore have inhibited gas flow. The Company is currently evaluating production alternatives to remove this water from the wellbores and re-configuring the gathering system to allow for the production of water in association with the natural gas.

The Company spent \$7,090,204 on capital expenditures during the year ended December 31, 2008. \$557,204 was spent on completion and test work on the Company's Ardley CBM prospective lands. The remainder of the 2008 capital expenditures were primarily spent on drilling and completion of 13 gross (12.0 net) Horseshoe Canyon CBM wells, and the construction of the gas processing facility at the Company's Thorsby area. Of the wells drilled and completed in 2008, seven gross wells, (7.0 net) were awaiting tie-in at December 31, 2008.

Richards Oil & Gas Limited has a significant land position with rights to the Ardley coals. From 2005 to early 2007 the Company committed capital of approximately \$13,540,000 and its technical expertise in an attempt to commercialize this resource. To date, the Company has not been successful in its attempt to commercialize this resource. Due to the higher costs and higher risk associated with the Ardley CBM resource, the Company has focused on developing the more profitable and predictable Horseshoe Canyon CBM resource. The Company will continue to hold these Ardley lands, subject to expiries, and will reactivate its investigation of this CBM resource if economic conditions and technical advances warrant further capital investments.



RESERVES

The increase in the Company's total proved plus probable reserves of 28% to 2,308 MBOE is primarily a result of the 2008 drilling and completion work on the Company's Thorsby property. As a result of the additional 12 gross wells drilled in 2008 at Thorsby, the lateral extent of the Horseshoe Canyon CBM formation on Company lands was substantiated and some additional reserves were also attributed to the various Edmonton sand intervals encountered. At December 31, 2008, 92 percent of the Company's reserves are attributable to the Horseshoe Canyon CBM. The remaining reserves are conventional in nature with 89 percent of those reserves now producing from the same wellbores as the Horseshoe Canyon CBM reserves.

Reserve information is based on an independent reserve evaluation report prepared by Sproule Unconventional Limited dated March 19, 2009, with an effective date of December 31, 2008. The report was prepared in accordance with the COGE Handbook and National Instrument 51-101 standards of disclosure for oil and gas activities. Complete NI 51-101 reserve disclosure will be filed on SEDAR in conjunction with the filing of the Company's 2008 audited financial statements and related MD&A.

OUTLOOK

Production challenges experienced on start-up at the Company's Thorsby property has resulted lower than expected initial production volumes negatively impacting the initial cash-flows from this property. These production challenges require additional and unexpected capital spending to rectify. The Company is addressing these production challenges in a very prudent and cost effective manner as significant capital outlays at Thorsby may not be economic given the current commodity price environment and therefore will not be considered until current and future natural gas prices recover significantly.

Recent market events, including disruptions in credit markets and other financial systems and the deterioration of global economic conditions have resulted in significant declines in commodity prices. As a result of the current commodity price and credit environment, management has restricted capital and administrative spending and continues to monitor financing opportunities to fund its future prospects and commitments. Management is also considering farming out interests in its oil and gas properties, asset dispositions and strategic alternatives in an effort to preserve shareholder value.

Forward-Looking Statements

This MD&A contains forward-looking financial and operational information including production and capital expenditures projections. The projections are based on the Company's expectations and are subject to a number of risks and uncertainties that could materially affect the results. Actual results achieved during the forward-looking period may differ materially from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in areas of operation; and other factors, many of which are beyond the control of Richards Oil & Gas Limited. The Company disclaims any intention or obligation to publicly update or revise any forward-looking statements or information whether as a result of new information, future events or otherwise, except as may be expressly required by applicable securities laws.



RESULTS OF OPERATIONS

Revenues

\$ Amounts	Year ended December 31		
	2008	2007	Change
Natural gas revenues	3,378,264	1,892,161	79%
Oil revenues	236,455	183,765	29%
Natural gas liquids revenues	39,033	26,407	48%
Total production revenue	3,653,752	2,102,333	74%

Production

	Year ended December 31		
	2008	2007	Change
Natural gas (mcf/day)	1,144	818	40%
Oil (bbl/day)	8	12	(33%)
Natural gas liquids (bbl/day)	2	1	100%
Total (BOE/day)	201	149	35%

Average Sales Price

	Year ended December 31		
	2008	2007	Change
Natural gas (\$/mcf)	\$8.07	\$6.34	27%
Oil (\$/bbl)	\$76.40	\$43.01	77%

Average Benchmark Sales Price

	Year ended December 31		
	2008	2007	Change
AECO (daily) natural gas (\$/mcf)	\$8.14	\$6.45	26%
WTI crude oil (\$US/bbl)	\$99.65	\$72.31	38%
Bow River blend crude oil (\$CAD/bbl)	\$84.10	\$53.36	58%
Exchange rate (\$US/\$CAD)	1.06	1.07	1%

Production for the year ended December 31, 2008 averaged 201 BOE per day representing a 35% increase over the same period in 2007. This increase is primarily the result of additional well completions and a full year of production from the Company's Morningside area. The year over year decline in oil production is primarily a result of natural declines and the shutting in of one well in late 2007 that was no longer producing economically. The Company has not hedged its production, and its crude oil, natural gas liquids and natural gas production is sold into spot markets.

The Company's realized average natural gas sales price for the year ended December 31, 2008 was \$8.07 per mcf, a 27% increase from the year end 2007 realized average sales price. This similar year over year natural gas price realized by the Company is consistent with the 26 percent increase witnessed in the changes in the year over year AECO (daily) natural gas market price.

Substantially all of the Company's production is natural gas and most of the natural gas sold by the Company is CBM, natural gas produced from coal formations. CBM is in all material respects the same as natural gas save for a variance in heating content and other elements contained within the produced gas stream. The Company currently receives pricing that typically averages 1% to 2% less than the weighted average of AECO (daily) natural gas market price which reflects the slightly lower heating content of CBM gas.



Royalties

\$ Amount except percentages	Year ended December 31		
	2008	2007	Change
Crown royalties	284,772	182,953	56%
Gross overriding and freehold royalties	215,375	209,658	3%
Total royalties	500,147	392,611	27%
Total royalties (\$/BOE)	\$6.81	\$7.20	(5%)
Average corporate royalty rate	14%	19%	(5%)

Royalties are paid to various government entities and other land, mineral rights and interest holders in respect of the Company's natural gas, natural gas liquids and oil production. For the year ended December 31, 2008 the Company incurred total net royalty expenses of \$500,147 which represents 14% of total production revenues recorded or \$6.81 on a per BOE basis. This represents an increase of 27% in total royalties incurred from 2008 to 2007 and is consistent with the increase in total production of 35%. The increase in total royalties was primarily driven from increases in Crown royalties paid at the Company's Morningside area, an area which is primarily Crown land.

Alberta Royalty Changes

On January 1, 2009 the new royalties proposed by the government of Alberta come into effect. The Company's lower productivity CBM wells will benefit under the new royalty framework and as a result Crown royalties are expected to decline by up to 50% of the rates experienced in 2008. Under the new royalty framework, Crown royalty rates are determined by both productivity and natural gas prices. The Company's Crown royalty rate will remain below 2008 levels at prices up to \$9.50 per mcf.

Production levels increased in December 2008 as a result of the Company commencing production from its Thorsby area. The majority of the Company's production from the Thorsby area is from freehold lands and attracts a static royalty rate which, in the current natural gas pricing environment, is greater than the Crown royalty rate under the new royalty framework. After giving effect to the new Province of Alberta Crown royalty framework and the change in the Company's production mix, total royalty rates for the Company are expected to average 15 to 17 percent in 2009.

Operating Expenses

\$ Amount	Year ended December 31		
	2008	2007	Change
Operating expenses	1,472,958	1,000,946	47%
Operating expenses (\$/BOE)	\$20.04	\$18.36	9%

Operating costs for the year ended December 31, 2008 increased 47% over 2007 and totaled \$1,472,958. This increase in operating expenses was primarily due to increased production levels which increased 35% year over year. On a per BOE basis operating costs increased 9% to \$20.04 per BOE from the \$18.36 per BOE incurred in 2007. This increase in per BOE operating expenses is primarily the result of higher costs associated with government imposed well testing obligations on Horseshoe Canyon CBM production and increased third party per mcf compression charges. Already in 2009 the Company has undertaken specific field operating initiatives, that when combined with further anticipated production volume increases, will reduce the Company's per BOE operating costs.



OPERATING NETBACKS

Year ended December 31, 2008

	Natural gas (\$/mcf)	Oil (\$/bbl)	Natural gas liquids (\$/bbl)	Total (\$/BOE)
Price	\$8.07	\$76.40	\$65.37	\$49.73
Net royalties	(\$1.08)	(\$9.96)	(\$27.32)	(\$6.81)
Operating expenses	(\$3.34)	(\$20.39)	(\$20.02)	(\$20.04)
Operating netback ⁽¹⁾	\$3.65	\$46.05	\$18.03	\$22.88

Note: Rounding has been applied to amounts within this table

Year ended December 31, 2007

	Natural gas (\$/mcf)	Oil (\$/bbl)	Natural gas liquids (\$/bbl)	Total (\$/BOE)
Price	\$6.34	\$43.01	\$52.19	\$38.56
Net royalties	(\$1.21)	(\$5.15)	(\$18.09)	(\$7.20)
Operating expenses	(\$3.05)	(\$19.44)	(\$17.14)	(\$18.36)
Operating netback ⁽¹⁾	\$2.08	\$18.42	\$16.96	\$13.00

Note: Rounding has been applied to amounts within this table

(1) See "Non-GAAP Measures"

NET LOSS AND FUNDS FROM OPERATIONS

The following table reconciles the Company's net loss to the reported funds from operations for the years ended December 31, 2008 and 2007.

\$ Amount	Year ended December 31		
	2008	2007	Change
Net loss	(2,553,207)	(15,556,641)	(84%)
Add items not involving cash			
Stock-based compensation	220,054	453,683	(52%)
Depletion and amortization	1,679,341	15,513,870	(89%)
Accretion of asset retirement obligation	63,609	49,375	29%
Accretion of discount on convertible debentures	405,520	404,412	-%
Future income tax reduction	-	2,456,383	n/a
Funds from operations⁽¹⁾	(184,683)	(1,591,684)	(88%)
Asset retirement expenditures	-	(195,454)	n/a
Net change in non-cash working capital	72,909	(39,841)	n/a
Cash flow from operating activities	(111,774)	(1,826,979)	(88%)

(1) See "Non-GAAP Measures"



NETBACK ANALYSIS

The following table summarizes the Company's operating netback and funds from operations on a BOE basis for the years ended December 31, 2008 and 2007.

\$ Amount	Year ended December 31		
	2008	2007	Change
Price	\$49.73	\$38.56	29%
Net royalties	(\$6.81)	(\$7.20)	(5%)
Operating expenses	(\$20.04)	(\$18.36)	9%
Operating netback ⁽¹⁾	\$22.88	\$13.00	76%
Net general and administrative expenses	(\$19.97)	(\$35.29)	(43%)
Interest and other income	\$1.87	\$5.38	(65%)
Interest and financing charges (cash basis)	(\$7.29)	(\$12.29)	(42%)
Funds from operations netback ⁽¹⁾	(\$2.51)	(\$29.20)	(91%)

(1) See "Non-GAAP Measures"

GENERAL AND ADMINISTRATIVE EXPENSES

\$ Amount	Year ended December 31		
	2008	2007	Change
Total general and administrative expenses incurred	1,767,169	2,403,434	(27%)
Less overhead recoveries	(235,396)	(209,362)	12%
Less capitalized overhead	(64,478)	(270,037)	(76%)
Net general and administrative expenses	1,467,295	1,924,035	(24%)
Net general and administrative expenses (\$/BOE)	\$19.97	\$35.29	(43%)

Net general and administrative expenses for the year ended December 31, 2008 totaled \$1,467,295 versus the \$1,924,035 incurred in 2007, a year over year reduction of 24%. This reduction in general and administrative expenses is a result of management's continued commitment to improve its administrative expense metrics.

STOCK-BASED COMPENSATION

\$ Amount	Year ended December 31		
	2008	2007	Change
Stock-based compensation	220,054	453,683	(52%)

The Company's stock-based compensation plan provides current employees, officers, directors, and consultants with the right to elect to receive common shares through the Company's stock option plan. Stock-based compensation expense totaled \$220,054 for the year ended December 31, 2008 compared to \$453,683 recorded in 2007, a decrease of \$233,629 or 52%. The reduction in the year over year comparison is due primarily to the timing, number, original fair market value and age of the options. The main factor influencing this decrease in stock-based compensation is that the 2008 issues of options occurred when the Company's share price was considerably lower than in the past periods. This results in a lower fair market value of the options when issued which translates into lower stock-based compensation cost than in previous years. Age of options is also a factor as a large percentage of the Company's options are a over two years old meaning a large portion of SBC expense related to these options has already been incurred.

There are a total of 4,790,000 stock options outstanding at an average exercise price of \$0.67 per share at December 31, 2008.



INTEREST AND FINANCING CHARGES

\$ Amount	Year ended December 31		
	2008	2007	Change
Interest on convertible debenture	520,000	520,000	nil%
Interest expense	15,790	150,071	(90)
Interest and financing charges (cash basis)	535,790	670,071	(20%)
Accretion of discount on convertible debentures	405,520	404,412	nil%
Total	941,310	1,074,483	(12%)

Interest and financing charges for the year ended 2008 totaled \$941,310, versus \$1,074,483 for the year ended 2007 representing a reduction of \$133,173 or 12%. This reduction is due almost exclusively to interest expense related to Part XII.6 tax incurred in 2007, a result of the Company's flow through commitment in that year. In 2008 the Company no longer has any flow through commitments and accordingly does not incur any related interest expense charges.

INCOME TAXES

The Company is currently not taxable, and the Company does not anticipate paying current income tax over the next several years. The Company's current tax rate is a combined Canadian federal and Alberta plus Saskatchewan provincial rate of 29.68%.

As at December 31, 2008 the oil and gas properties owned by the Company have a tax basis of approximately \$31,447,000 (2007 – \$24,528,000) available for future use as deductions from taxable income. Included in this tax basis are non-capital loss carry forwards of approximately \$15,311,000 (2007 – \$10,827,000) which expire in the years 2014 to 2028.

CAPITAL EXPENDITURES

The Company spent \$7,090,204 on capital expenditures during the year ended December 31, 2008. \$557,204 was spent on completion and test work on the Company's Ardley CBM prospective lands. The remainder of the 2008 capital expenditures were primarily spent on drilling and completion of 13 gross (12.0 net) Horseshoe Canyon CBM wells, and the construction of the gas processing facility at the Company's Thorsby area. Of the wells drilled and completed in 2008, seven gross wells, (7.0 net) were awaiting tie-in at December 31, 2008.

The following table summarizes the Company's investment activities by types and compares the specific expenditure to the expenditures made in the previous year:

\$ Amount	Year ended December 31		
	2008	2007	Change
Land	45,156	253,125	(82%)
Geological and geophysical	64,733	201,231	(68%)
Drilling and completion	3,754,693	7,775,468	(52%)
Well equipment and facilities	3,214,970	1,558,726	106%
Disposition of oil and gas properties	-	(38,000)	n/a
Office equipment and leaseholds	10,652	11,369	(6%)
Total	7,090,204	9,761,919	(27%)



LIQUIDITY AND CAPITAL RESOURCES

Credit Facilities

The Company maintains two fully secured, demand credit facilities with a Canadian chartered bank. At December 31, 2008 the credit facilities in place for Richards Oil & Gas Limited consist of a \$2,000,000 revolving operating demand loan ("Facility A") and a \$2,000,000 non-revolving acquisition / development demand loan ("Facility B"). The per annum interest rate for Facility A is the bank's prime lending rate plus 1.0 percent and for Facility B is the bank's prime lending rate plus 1.5 percent. Monthly principal repayments of Facility B commence one month after draw down and the repayment amount is calculated using the estimated half-life of the reserves being financed.

Pursuant to an interim review conducted in January 2009, the bank re-confirmed the borrowing bases at \$2,000,000 for Facility A and \$2,000,000 for Facility B and amended the per annum interest rate payable under the current credit facilities. The per annum interest rate for Facility A increased to the bank's prime lending rate plus 1.5 percent and for Facility B the per annum interest rate increased to the bank's prime lending rate plus 2.0 percent. The next scheduled review is to be completed on or before April 30, 2009. As the available borrowing bases of both facilities are based on the bank's interpretation of the Company's reserves, development prospects and future commodity prices, there can be no assurance that the amount of available facilities will not decrease at the next scheduled review on or before April 30, 2009.

The facilities are subject to a financial-based covenant requiring the Company to maintain a working capital ratio (adjusted for the undrawn portion of Facility A) of no less than 1:1. At December 31, 2008 the Company had drawn \$2,000,000 on its Facility B and was in compliance with the working capital covenant described above. At the date of this report, April 7, 2009 the Company had drawn \$1,675,000 on its Facility A and \$1,700,000 on its Facility B.

Capital Resources

At December 31, 2008, the Company has a net working capital deficit of \$3,168,682. The large working capital deficit is due to significant accounts payable and accrued liabilities balances associated with the large capital program in the last quarter of the year. The Company has at present total credit facilities of \$4,000,000 as described above.

Recent market events, including disruptions in credit markets and other financial systems and the deterioration of global economic conditions have resulted in significant declines in commodity prices. As a result of the current commodity price and credit environment management has restricted capital and administrative spending and continues to monitor financing opportunities to fund its future prospects and commitments. Management is also considering farming out interests in its oil and gas properties, asset dispositions and strategic alternatives in an effort to continue operations.

Current capital resources available

<i>\$ Amount</i>	
Capital resources	
Working capital deficit at December 31, 2008	(3,168,682)
Credit facilities available at December 31, 2008	4,000,000
Total capital resources available	831,318



Capitalization

Outstanding Common Shares		
Weighted average outstanding common shares		
- Basic and diluted at December 31, 2008	72,661,602	
Outstanding securities at December 31, 2008		Average price per share
- Common shares	72,661,602	-
- Common share options	4,790,000	\$0.67
- Common share warrants	15,625,007	\$0.40
- Shares issuable on conversion of convertible debentures	3,571,429	\$1.82

Total Market Capitalization

The Company's total market capitalization at December 31, 2008 was \$2.5 million.

<u>\$ Amount except for per share information</u>	
Outstanding common shares at December 31, 2008	72,661,602
Common share price (<i>closing price on the TSX Venture exchange on December 31, 2008</i>)	\$0.035
Total market capitalization	2,543,000

As at April 7, 2009 the total issued and outstanding shares in the Company was 72,661,602.

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not utilize any off-balance sheet arrangements.



QUARTERLY FINANCIAL SUMMARY

The Company's quarterly summaries for the most recent two-year period to date are as follows:

\$ Amount except for per unit amounts	Q4 2008	Q3 2008	Q2 2008	Q1 2008	Q4 2007	Q3 2007	Q2 2007	Q1 2007
Sales – Natural gas (mcf/day)	1,149	1,023	1,174	1,232	946	655	609	1,065
Sales – Oil and natural gas liquids (bbls/day)	10	11	8	12	11	13	13	16
Sales – Total (BOE/day)	201	182	204	217	169	122	114	193
Average Natural gas price (\$/mcf)	\$6.64	\$7.65	\$10.03	\$7.90	\$5.96	\$4.92	\$7.10	\$7.13
Average Oil and natural gas liquids price (\$/bbl)	\$41.54	\$97.56	\$97.74	\$63.08	\$45.97	\$47.42	\$41.17	\$41.96
Total production revenue	738,427	822,612	1,143,569	949,144	565,369	353,086	441,256	742,622
Interest and other revenue	12,260	19,748	25,791	79,956	104,363	104,278	36,802	48,203
Royalty expense	108,089	125,021	117,730	149,307	90,233	48,754	46,004	207,620
EXPENSES								
Operating expense	403,386	379,919	335,236	354,417	338,615	219,898	223,707	218,726
General and administrative expenses	288,171	347,185	466,195	381,239	249,179	353,977	538,193	782,686
Stock-based compensation	18,623	38,523	111,951	50,957	54,037	152,492	161,904	85,250
Interest and financing charges	232,645	232,839	229,861	230,470	244,092	260,829	290,391	279,171
Depletion, amortization & accretion expense	497,167	443,496	388,379	413,908	390,271	318,993	283,547	470,434
Impairment of oil and gas properties	-	-	-	-	8,250,000	3,700,000	2,150,000	-
Future income tax reduction	-	-	-	-	(7,081)	(1,188,588)	(960,795)	(299,919)
Net income (loss)	(797,394)	(724,623)	(479,992)	(551,198)	(8,939,614)	(3,408,991)	(2,254,893)	(953,143)

Q4 2008 - Natural gas production volumes increased as new CBM wells were brought on production at the Company's Thorsby property. Lower general and administrative levels are a result of Company efforts to continually reduce general and administrative expenses.

RELATED PARTY TRANSACTIONS

During 2008, the Company paid \$35,675 for consulting services to a firm of which a director of the Company is the President. As at December 31, 2008, the Company owed \$98,368 to the same firm.

COMMITMENTS

The Company is committed to payments under an operating lease for office space over the next four years. The operating lease commitment, before operating costs, for the next four years are as follows; 2009 - \$136,192, 2010 - \$140,415, 2011 - \$144,638 and 2012 - \$148,860.

NEW ACCOUNTING POLICIES

As of January 1, 2008, The Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1400, "General Standards of Financial Statement Presentation"; Section 1535 "Capital Disclosures"; Section 3031 "Inventories"; Section 3862 "Financial Instruments – Disclosures", and Section 3863 "Financial Instruments – Presentation". These standards have been applied prospectively and accordingly the prior period financial statements have not been restated.



CICA Section 1400, General Standards of Financial Statement Presentation, was amended to include requirements to assess and disclose an entity's ability to continue as a going concern. The new requirements are effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008. The adoption of this standard did not have an impact on the Company's financial statements.

CICA Section 1535 establishes standards for disclosing information regarding an entities capital and how it is managed. The section specifies the disclosure of i) an entities objectives, policies, and processes for managing capital; ii) quantitative data about what the entity regards as capital; iii) whether the entity has complied with any capital requirements; and iv) if it has not complied, the consequences of such noncompliance.

CICA Sections 3862 and 3863 replace section 3861 "Financial Instruments – Disclosure and Presentation" which revises and enhances financial instruments disclosure requirements and leaves unchanged its presentation requirements. The objective of section 3862 is to provide financial statement disclosure to enable users to evaluate the significance of financial instruments for the Company's financial position and performance. The section also requires increased disclosure on the nature and extent of risks arising from financial instruments that the Company is exposed to during the reporting period and the balance sheet date and how the Company is managing those risks. The purpose of section 3863 is to enhance the financial statement users' understanding of the significance of financial instruments to the Company's financial position, performance and cash flows.

FUTURE ACCOUNTING POLICIES

As of January 1, 2009, the Company will be required to adopt CICA Handbook Section 3064 Goodwill and Intangible Assets which replaces CICA Handbook Sections 3062 Goodwill and Other Intangible Assets and Section 3450 Research and Development Costs. The Company is assessing the impact of this new standard on its financial statements; however, the adoption is not expected to have a material impact on its financial statements.

In December 2008, the CICA issued Section 1582 Business Combinations, replacing Section 1581. Section 1582 includes significant changes to the measurement of purchase consideration in a business combination. Under Section 1582, the fair value ascribed to shares issued as consideration in a business combination will be based on their market value at the date of exchange, as compared to the current standard which prescribes market price for a reasonable period of time before and after the date of acquisition. In addition, the majority of acquisition costs will likely have to be expensed. Current standards allow for the capitalization of these costs as part of the purchase price. Section 1582 also addresses contingent liabilities, which will be required to be recognized at fair value on acquisition, and subsequently remeasured at each reporting date until settled. Currently, standards require only contingent liabilities that are payable to be recognized. Section 1582 also requires negative goodwill to be recognized in earnings rather than the current standard of deducting from non-currents assets in the purchase price allocation. Section 1582 will be effective for the Company on January 1, 2011, with prospective application.

The Accounting Standards Board of the Canadian Institute of Chartered Accountants has recently confirmed that in the year 2011 International Financial Reporting Standards ("IFRS") will replace current GAAP for publically accountable profit-oriented enterprises in Canada. The official changeover date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Companies will be required to provide comparative IFRS information for the previous fiscal year. At present the Company is actively monitoring and assessing the impact of convergence of Canadian GAAP and IFRS.



ADVISORIES

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to provide reasonable assurance that information required to be disclosed by the Company is accumulated and communicated to management as appropriate to allow timely decisions regarding required disclosure. The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their assessment, that the disclosure controls and procedures in place are effective to provide reasonable assurance that material information related to Richards Oil & Gas Limited is made known to them. It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's disclosure controls and procedures are effective, except for the material weaknesses in design of the internal controls noted below, they do not expect that the disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable assurance, not absolute assurance, that the objectives of the control system are met.

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Richards Oil & Gas Limited are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Management has identified certain weaknesses that it considers necessary to disclose in order to present an accurate and complete picture of the condition of the design of the Company's internal controls over financial reporting.

- i. The Company is not able to achieve appropriate segregation of incompatible accounting duties, with its current accounting staff complement.
- ii. The Company does not have a sufficient number of financial accounting personnel with the technical accounting knowledge to address all complex and non-routine accounting transactions that may arise.

Management and the board of directors work to mitigate the risk of a material misstatement in financial reporting, through the review of financial accounting processes, financial disclosures and communication with the external auditors. The Company does not believe that the additional costs to hire additional personnel to mitigate these weaknesses are justifiable at this stage in the Company's development.

BOE Presentation

Throughout this MD&A BOE, or barrel of oil equivalent, is defined as 6 Mcf to 1 bbl. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Non-GAAP Measures

The Company's management uses and reports certain non-GAAP measures in the evaluation of operating and financial performance. Specifically, this MD&A contains the terms "operating netback" and "funds from operations" which the Company views as non-GAAP measures of operating and financial performance. These measurements should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with Canadian GAAP as an indicator of the Company's performance. The Company's determination of funds from operations and operating netback may not be comparable to that reported by other companies. Richards Oil & Gas Limited's peer companies in the oil and gas industry use the same definitions and for consistency the Company will continue to report in this manner.



Funds from operations are determined as operating cash flows before working capital adjustments and abandonment expenditures. Funds from operations is used by the Company to analyze operating performance, leverage and liquidity. Readers should refer to the "NET LOSS AND FUNDS FROM OPERATIONS" section of the MD&A for a reconciliation of funds from operations.

The Company uses the term Operating Netbacks to evaluate operational performance of the Company. Operating netback, which is calculated as average unit sales price less royalties, and operating expenses, represents the operating cash margin for every barrel oil equivalent sold. Readers should refer to the "OPERATING NETBACKS" section of the MD&A for the calculations of operating netbacks.