

MANAGEMENT'S DISCUSSION and ANALYSIS

ADVISORIES

This Management's discussion and analysis ("MD&A"), prepared effective March 16, 2009 should be read in conjunction with the Ironhorse Oil & Gas Inc. ("Ironhorse" or the "Company") audited financial statements for the years ended December 31, 2008 and December 31, 2007.

Basis of Presentation - The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and measurement currency in the financial statements and in this discussion and analysis is the Canadian dollar, unless otherwise stated.

Non-GAAP Measures - Ironhorse evaluates performance based on net income, funds from operations, funds from operations per share, net debt and field netback. Funds from operations, funds from operations per share, net debt and field netback are not measurements defined by GAAP, but are financial terms commonly used in the oil and gas industry.

Funds from Operations are labelled on the Statement of Cash Flows and may not be comparable to other companies. Ironhorse calculates funds from operations as cash flow from operating activities prior to changes in non-cash working capital, and per share amounts are determined using the same method and shares outstanding, which are used in the determination of net earnings per share. The Company considers it a key measure as it demonstrates the ability of the Company to generate the funds necessary to finance future capital investments.

Field Netback - Ironhorse also uses field netback as a key performance indicator. Field netback does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Field netback is determined by deducting royalties and operating expenses from petroleum and natural gas sales revenue. The Company considers field netback a key measure in assessing the efficiency of its oil and gas assets.

Net Debt - Ironhorse also uses net debt as a key performance indicator. Net debt is calculated as current liabilities less current assets.

Funds from operations and field netback are not intended to represent operating profits, nor should they be viewed as an alternative to other measures of financial performance calculated in accordance with GAAP.

Boe Conversion - Certain natural gas volumes have been converted to barrels of oil equivalent ("boe"), whereby six thousand cubic feet ("mcf") of natural gas is equal to one barrel ("bbl") of oil, unless otherwise stated. This conversion ratio is based on an energy equivalent conversion applicable at the burner tip and does not represent a value equivalency at the wellhead.

Forward-Looking Information - Certain information regarding Ironhorse set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Ironhorse's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of or availability of qualified technical personnel or management, stock market volatility and ability to access capital from internal and external sources. Ironhorse's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what impact it would have on Ironhorse. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue", and similar expressions have been used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management.

Examples of forward-looking statements in this MD&A include, but are not limited to the following, each of which is subject to significant risks and uncertainties and is based on assumptions which may prove to be incorrect:

- The expectation that the two (0.4 net) Pembina oil wells will be placed on production in the fourth quarter of 2009. These wells are initially expected to increase our net production by 150 boe per day and once we establish a pressure maintenance scheme they should increase our net production by 600 - 800 boe per day. Regulatory and/or operational delays could negatively impact the timing and production increases from this project.
- The expectation that the Company has sufficient financial resources to undertake and complete its remaining 2009 priorities including: the tie in of the Pembina oil wells; the establishment of pressure maintenance scheme at Pembina and fulfilling its remaining flow through expenditure obligations. This is subject to the risk and uncertainty of the Company's \$14.5 million credit facility renewing at substantially lower levels and funds from operations being lower than the budgeted. Projected oil and gas commodity prices and production rates could vary significantly from current estimates resulting in decreases in our credit facility and/or funds from operations.

Risk Factors

Additional risk factors can be found under "Risk Factors" in the Company's Annual Information Form, which can be found on www.sedar.com. Many risks are discussed below, but these risk factors should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause actual results or events to differ materially from forecast results.

Oil and natural gas operations involve many risks that even a combination of experience and knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on the Company's ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

The Company's principal risks include finding and developing economic hydrocarbon reserves efficiently and being able to fund the capital program. The Corporation's need for capital is both short-term and long-term in nature. Short-term working capital will be required to finance accounts receivable, drilling deposits and other similar short-term assets, while the acquisition and development of oil and natural gas properties requires large amounts of long-term capital. The Company anticipates that future capital requirements will be funded through a combination of funds from operations, debt and/or equity financing. There is no assurance that debt and equity financing will be available on terms acceptable to the Company to meet its capital requirements. If any components of the Company's business plan are missing, the Company may not be able to execute the entire business plan.

Although the Company has no set policy concerning derivative financial instruments, the management of the Company may use derivative financial instruments to reduce corporate risk in certain situations.

Internal Controls over Financial Reporting

Recent changes in securities laws no longer require the CEO and CFO of TSX Venture Exchange listed companies such as Ironhorse to certify they have designed internal control over financial reporting, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Instead, an optional form of certification has been made available to TSX Venture Exchange listed companies and has been used by Ironhorse's certifying officers for the December 31, 2008 annual filings. The new certification reflects what the Company considers to be a more appropriate level of CEO and CFO certification given the size and nature of the Company's operations. This certification requires that the certifying officers state:

- i) they have reviewed the annual MD&A and financial statements;
- ii) they have determined there is no untrue statement of a material fact, or any omission of material fact required to be stated which would make any statement not misleading in light of

the circumstances under which it was made within the annual MD&A and financial statements;

- iii) that based upon their knowledge, the annual filings, together with the other financial information included in the annual filings, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of the date and for the periods presented in the filings.

Business Strategy

The business plan of the Company is to create profitable per share value growth in the exploration for, and the development and production of, natural gas and crude oil in western Canada. Ironhorse pursues a growth strategy involving exploratory and development drilling augmented by strategic acquisitions of properties and companies where exploitation, development and exploration opportunities exist. The Company's current areas of focus are in the western Canada corridor trending from northeast British Columbia to southwest Saskatchewan.

Ironhorse's strategy involves acquiring crown, freehold and First Nation mineral rights where our management and technical team have expertise. We believe this creates a competitive advantage for the Company.

Fourth quarter 2008 overview

For the three months ended December 31, 2008, production averaged 921 boe per day, a 39% increase from the 664 boe per day in the corresponding period of 2007. Year over year production increases resulted from the 2007/2008 drilling program at Shackleton, Saskatchewan. Production peaked in the second quarter of 2008 at an average rate of 1,143 boe per day and decreased through out 2008 due to normal declines.

Higher production and gas prices during the quarter ended December 31, 2008 resulted in funds from operations of \$1.5 million versus \$0.7 million in fourth quarter of 2007. Ironhorse closed a private placement in October 2008 for gross proceeds of \$3.5 million. During the fourth quarter the Company incurred capital expenditures of \$2.6 million related primarily to the Shackleton 2008/2009 winter drilling program. The result of these activities was net debt decreased during the fourth quarter by \$2.1 million to \$6.4 million at December 31, 2008.

Outlook

The Company will continue developing its Shackleton, Saskatchewan shallow gas property in 2009. During the first quarter of 2009 the Company drilled and placed on production 32 (16 net) gas wells in the Shackleton area which increased our net production to over 1,250 boe per day in early March of 2009. Production for the first quarter of 2009 is expected to average 1,000 boe per day based on field estimates received to date.

During the first quarter of 2009 Ironhorse drilled two (0.4 net) Nisku oil wells in the Pembina, Alberta area. Both wells will be completed after April 1, 2009 and work has begun to place the wells on production. We expect these wells will be placed on production early in the fourth quarter of 2009. These wells are initially expected to increase our net production by 150 boe per day and once we establish a pressure maintenance scheme they should increase our net production by 600 - 800 boe per day. These estimates of production rates are based on management's analysis of the well logs, flow test data and comparisons to analogous wells in the area. Actual production rates and the timing for placing the wells on production could be materially different due to factors beyond our control including regulatory approvals. The addition of these oil wells will provide Ironhorse with a more balanced gas/oil production mix.

Year over year increases in production in 2009 are expected to be offset by lower oil and gas commodity prices. As a result the Company is closely monitoring its capital expenditures for the balance of 2009 with a priority to placing the Pembina oil wells on production and fulfilling our flow-through share expenditure obligations.

Ironhorse remains committed to its strategy of exploring for and developing new focus areas through a combination of “grass roots” exploration and by evaluating asset and corporate acquisition candidates.

Impact of Current Economic Volatility and Uncertainty

The current economic volatility and uncertainty in Canada and around the world has contributed to dramatic decreases in oil and gas commodity prices and restricted access to new capital. In response to these volatile and uncertain times Ironhorse is constantly monitoring its planned capital expenditures, funds from operations and available credit facilities. We believe the Company has sufficient financial resources in 2009 to undertake a \$12 million capital program. Highlights of the budget are as follows:

- The 2008/2009 Shackleton drilling program undertaken in the first quarter of 2009 has been substantially completed in the first quarter of 2009 under budget. We estimate actual net costs incurred in the first quarter to be approximately \$4.5 million, with costs remaining to be incurred this year estimated at \$0.5 million;
- Place the two (0.4 net) Pembina oil wells drilled in the first quarter of 2009 on production in the fourth quarter of 2009, and in the fourth quarter drill the water injection and water source wells necessary for pressure maintenance. Net costs incurred in the first quarter of 2009 with respect to drilling and completing the two wells are estimated at \$1.6 million, with the net cost of placing the wells on production including completion, equipping and pipelining estimated at \$2.5 million, and the net cost of establishing a pressure maintenance scheme estimated at \$0.7 million and
- Fulfill remaining flow-through share expenditure obligations which are estimated at \$2.2 million.

The Company currently has a \$14.5 million credit facility which we expect will be renewed at current or slightly higher levels as a result of the drilling successes to date in 2009. Further declines in gas prices could negatively impact the amount of the credit facility available. At December 31, 2008 we had drawn \$6.4 million, leaving approximately \$8 million to finance capital expenditures in 2009. Management believes funds from operations will be sufficient to finance the remaining planned capital expenditures and provide financial flexibility should production rates or commodity prices decline.

Funds from operations for 2009 are budgeted to exceed \$6 million. Actual results will vary depending on oil and gas commodity prices, production declines on our Shackleton gas wells and the timing for placing the Pembina wells on production. Our current estimate for funds from operations assumes production will average 1,150 to 1,250 boe per day with the Shackleton gas wells experiencing similar decline rates as wells drilled in prior years and the Pembina oil wells being placed on production in the fourth quarter. Gas prices are assumed to average \$5.00 per mcf for the year and oil prices in the fourth quarter of 2009 will average \$50 per bbl at the wellhead. Given that all the Shackleton gas wells were placed on production prior to March 15, 2009, we believe the greatest risk in our estimate for funds from operations stems from greater than expected declines from the new gas wells, delays in tying in the Pembina oil wells and lower than expected gas prices. Management is continually reviewing its operations and making adjustments to its capital expenditures to accommodate differences between assumptions made and actual results.

Years Ended December 31

SELECTED INFORMATION	2008	2007	2006
Thousands except per share amounts			
Financial			
Revenue	17,965	9,041	2,766
Royalties	(6,883)	(3,410)	(1,092)
Funds from operations	8,001	3,529	1,050
Net income (loss)	1,586	(812)	(733)
Net income (loss) per share – basic and diluted	0.08	(0.04)	(0.04)
Total assets	32,199	25,843	16,849
Capital expenditures	10,556	12,406	13,913
Net debt	(6,789)	(7,983)	(4,337)
Weighted average shares outstanding			
- basic	20,225	19,411	16,346
- fully diluted	20,352	19,411	16,346
Operations			
Production			
Gas – mcf/d	6,434	3,977	1,162
Oil & ngl's – bbl/d	7	7	8
Total – boe/d	1,079	670	202
Average sales price			
Gas - \$/mcf	7.52	6.09	5.92
Oil - \$/bbl	67.00	71.06	66.18
Royalty - \$/boe	17.42	13.95	14.82
Operating expenses - \$/boe	2.29	3.32	4.30
Field Netback - \$/boe	25.74	19.68	17.66
General & administrative expenses - \$/boe	3.44	3.64	3.91

OPERATIONS

Our operations are focused in Shackleton, Saskatchewan, Pembina, Alberta and NE British Columbia. In addition to these areas, we are constantly evaluating new areas which have the potential to become a focus area.

Shackleton is a shallow gas development project. We have drilled and placed on production 100 (50 net) gas wells over the past four winters. We are evaluating the economics of an infill drilling program which would see the Company drill up to 100 (50 net) additional gas wells. The economics of this project would be significantly enhanced if one or more of the following were to occur: fall access as opposed to "winter only" drilling would significantly reduce drilling costs; higher gas prices; lower royalties; or some combination of all of the above.

We participated in a significant oil discovery in the Pembina area this winter. We have drilled two (0.4 net) Nisku oil wells which we are working towards placing on production in the fourth quarter of 2009. These two oil wells will initially be subject to a combined production allowable of approximately 700 to 800 (130 to 150 net) boe per day. Once a pressure maintenance scheme is established Ironhorse expects to increase production from the two oil wells to a combined rate of approximately 3,000 to 4,000 (600 to 800 net) boe per day. Ironhorse's net capital costs, to place the two oil wells on production, is estimated to be \$2.5 million. The Company's net cost of a pressure maintenance scheme is estimated at \$0.7 million. Ironhorse has the ability to finance these activities with currently available credit facilities and funds from operations. The timing and costs for undertaking these activities represents our best estimate at this time. Various factors beyond the Company's control, including regulatory approvals, could result in delays.

NE British Columbia is our newest focus area. In 2008 we acquired crown lands and trade seismic and are planning to drill a well (0.5 net) later this year.

Sales Volumes

		Three Months Ended December 31			Year Ended December 31		
		2008	2007	Change	2008	2007	Change
Daily sales volumes							
Natural gas	<i>mcf/d</i>	5,486	3,934	39%	6,434	3,977	62%
Light oil & ngl's	<i>bbbls/d</i>	7	8	(13%)	7	7	0%
Total	<i>boe/d</i>	921	664	39%	1,079	670	61%

Sales volumes for the year ended December 31, 2008 averaged 1,079 boe per day, an increase of 61% from the 670 boe per day during the corresponding period in 2007. Natural gas volumes increased to 6,434 mcf per day, a 62% increase from the corresponding 2007 period volume of 3,977 mcf per day. The increase in natural gas production is the result of the first quarter drilling program which resulted in an additional 31 (15 net) gas wells being placed on production in the Shackleton area, bringing the total number of producing wells to 68 (34 net). The Company experienced natural declines on its gas production during the year which resulted in an exit rate of approximately 875 boe per day at the end of December 2008.

Sales volumes at the Shackleton property have increased during the first quarter of 2009 when we placed an additional 32 (16 net) gas wells on production. Our net production rate increased to over 1,250 boe per day in March. The new Shackleton gas wells are expected to experience similar decline rates to wells drilled in previous years. Our Pembina Nisku oil discoveries are expected to be on production in the fourth quarter of 2009. The initial production allowable rates for the wells will be approximately 700-800 (130 to 150 net) boe per day. Once a pressure maintenance scheme is established production from the wells is expected to increase to 3,000 to 4,000 (600 to 800 net) boe per day. We plan on having the pressure maintenance scheme in place by the first quarter of 2010. The timing and cost for these undertakings represents our best estimate at this time, various factors beyond the Company's control including regulatory approvals could result in delays.

The Company estimates 2009 production will average 1,150 to 1,250 boe per day assuming the new Shackleton gas wells perform consistent with prior years and the Pembina oil wells are placed on

production in the fourth quarter of 2009 at their initial production allowable rates. Actual results could differ significantly from these estimates due to factors beyond management's control including regulatory delays.

Marketing and Revenue

Commodity pricing	Three months ended December 31			Year Ended December 31			
	2008	2007	Change	2008	2007	Change	
Benchmark							
Alberta Spot – Natural gas	\$/mcf	6.77	6.19	9%	8.18	6.48	26%
West Texas Intermediate - Oil	US\$/bbl	58.45	90.73	(36%)	99.20	72.37	37%
Edmonton Par - Oil	\$/bbl	65.59	86.79	(24%)	102.95	76.65	34%
Company Prices							
Natural gas price	\$/mcf	6.72	5.99	12%	7.52	6.13	23%
Light oil price	\$/bbl	54.41	76.97	(29%)	92.47	71.06	30%
Boe	\$/boe	40.40	36.47	11%	45.45	36.95	23%
Revenue							
Natural gas	\$m	3,390	2,170	56%	17,714	8,846	100%
Light oil & ngls	\$m	34	57	(40%)	241	186	30%
Other	\$m	3	-	-	10	9	11%
Total	\$m	3,427	2,227	54%	17,965	9,041	99%

The Company's Shackleton gas production is marketed through the marketing arm of a large international oil and gas company. Ironhorse's gas receives the Alberta gas spot price plus \$0.02 per gigajoule ("GJ") less a transportation charge of approximately \$0.13 per GJ. Alberta spot gas prices are based on Natural Gas Exchange prices at the AECO Hub. Natural gas pricing tends to be volatile and is affected by supply and demand, storage levels, weather conditions and fuel switching to alternative sources of energy. Alberta spot natural gas prices increased 26% in 2008 compared to 2007. Gas prices peaked in the second quarter of 2008 and have generally drifted down throughout the balance of 2008 and early 2009. During 2008 approximately 75% of Ironhorse's natural gas production was sold on the spot market and 25% was sold at contracted prices. As a result of the contracted pricing agreements Ironhorse's realized gas price was approximately \$0.20 per mcf lower than it would have been if all the gas had been sold at spot prices. The Company's natural gas receives a price which is lower than the average benchmark price due to the lower heat content per mcf for Shackleton natural gas.

The Company monitors the impact of commodity price exposure and from time to time, enters into structured sales contracts such as swaps, options or collars for fixed periods of time to mitigate commodity price risk. The objective of this strategy is to reduce the Company's risk exposure to changes in funds from operations resulting from changes in commodity prices, thereby ensuring our ability to complete the planned capital investment program.

Management entered into the following natural gas sales contracts with respect to 2008/2009:

- For the period April 1, 2008 to October 31, 2008 the Company entered into a fixed price natural gas sales contract for 2,000 GJ per day at \$7.05 per GJ.
- For the 2008/2009 winter heating season covering November 1, 2008 to March 31, 2009, Ironhorse entered into two "costless collar" physical natural gas sales contracts. One contract is for 1,000 GJ per day based on a floor price of \$7.75 per GJ and a ceiling price of \$9.45 per GJ. The other contract is for 500 GJ per day with a floor price of \$8.00 per GJ and a ceiling price of \$10.00 per GJ.
- For the period covering April 1, 2009 to October 31, 2009, the Company has entered into three physical natural gas sales contracts. The first is a fixed price contract of \$4.03 per GJ for 1,000

GJ per day. The second is a costless collar with a floor price of \$3.50 per GJ and a ceiling of \$4.52 per GJ for 500 GJ per day. The third contract is a three way collar with a floor of \$3.50 per GJ and a ceiling of \$4.85 per GJ and a put for \$2.75 per GJ for 500 GJ per day. The three way collar works as follows: if the gas price is between \$2.75 and \$3.50 per GJ then price received is \$3.50 per GJ. If the gas price is below \$2.75 per GJ then the price received by the Company is spot plus \$0.75 per GJ.

Revenues for the year ended December 31, 2008 were reduced by \$0.4 million as a result of these natural gas price contracts. If the remaining contracts had been closed out on December 31, 2008 the Company would have realized a gain of approximately \$0.25 million.

Sales revenues for the year ended December 31, 2008 increased 99% to \$18 million from \$9 million in 2007 as a result of the increase in sales volumes and higher natural gas prices.

The sales revenues for the quarter ended December 31, 2008 were \$3.4 million, an increase of 54% over the \$2.2 million in the corresponding period in 2007. Sales revenues for the fourth quarter of 2008 were increased by \$0.2 million due to the gas price contracts discussed above.

Sales revenues in 2009 will be positively influenced by increased production from the wells drilled in Shackleton and Pembina and negatively impacted if commodity prices for oil and natural gas remain at current or lower levels.

Royalties

		Three Months Ended December 31			Year Ended December 31		
		2008	2007	Change	2008	2007	Change
Royalties	\$m	1,098	832	32%	6,883	3,410	102%
Royalties per boe	\$	12.95	13.63	(5%)	17.42	13.95	25%
Royalty rate	%	32.07	37.36	(14%)	38.34	37.75	2%

Ironhorse's producing wells are subject to crown, First Nation and overriding royalties which are payable to the owners of the mineral rights. The mineral rights for Company's Shackleton property are owned by the Carry the Kettle First Nation and are subject to a lessor royalty and a gross overriding royalty. The lessor royalty is equivalent to Saskatchewan crown royalty and the gross overriding royalty is a sliding scale minimum 15%. Royalty rates vary based on a number of factors including commodity and reference pricing and production rates. Royalties are calculated on sales revenues based on daily spot prices and without reference to gas price contract adjustments.

For the year ended December 31, 2008 royalties increased 102% to \$6.9 million (\$17.42 per boe) compared to \$3.4 million (\$13.95 per boe) in 2007. The increase in royalties for the period is attributable to increased natural gas production and higher natural gas prices.

Royalties for the fourth quarter of 2008 increased 32% to \$1.1 million (\$12.95 per boe) compared to \$0.8 million (\$10.80 per boe) for 2007. The royalty rate during the quarter was 32.07% of sales compared to 37.36% in the same period of 2007. The increase in royalties paid during the quarter was due to increased production and higher natural gas prices. The lower royalty rate per boe is due to higher revenues from gas price contract adjustments in the fourth quarter which increased revenues by \$0.2 million.

Royalties are expected to be approximately 28 - 32% in 2009, depending on gas prices, until such time as the Pembina oil wells are placed on production. The first 50,000 barrels of gross production from each of the Pembina oil wells is eligible for the reduced royalty rate of 5% announced by the Alberta provincial government on March 2, 2009. The announcement also includes drilling incentives in the form of royalty credits for wells drilled from April 1, 2009 to April 1, 2010. To the extent that the Company fulfills its outstanding flow through expenditure commitments by drilling wells in Alberta, it will earn additional royalty relief.

Operating Expenses

		Three Months Ended December 31			Year Ended December 31		
		2008	2007	Change	2008	2007	Change
Operating expenses	\$m	261	262	0%	903	812	11%
Per boe	\$	3.08	4.29	(28%)	2.29	3.32	(31%)

Operating expenses were \$0.3 million, or \$3.08 per boe, for the quarter ended December 31, 2008 consistent with the \$0.3 million or \$4.29 per boe, during the comparable period of 2007. The lower rate per boe was due to higher production levels in the period.

Operating expenses for the year ended December 31, 2008 increased 11% to \$0.9 million (\$2.29 per boe) from \$0.8 million (\$3.32 per boe) during the corresponding period in 2007. The lower cost per boe is attributable to improved economies of scale from increased production.

Operating expenditures in 2009 are expected to be \$2.00 - \$2.50 per boe. Our operating expenses on a boe basis compare favourably to peers in the industry as we own the infrastructure necessary to produce the gas at Shackleton.

General and Administrative Expense (“G&A”) and Stock Based Compensation (“SBC”)

		Three Months Ended December 31			Year Ended December 31		
		2008	2007	Change	2008	2007	Change
G&A	\$m	405	224	81%	1,356	891	52%
SBC	\$m	86	121	(29%)	514	422	22%
Per boe:							
G&A	\$	4.78	3.67	30%	3.44	3.64	(5%)
SBC	\$	1.01	1.98	(49%)	1.30	1.72	(25%)

For the quarter ended December 31, 2008, G&A increased 81% from \$0.2 million to \$0.4 million due to higher management fees and fees paid to third party consultants.

For the year ended December 31, 2008 G&A increased 52% to \$1.4 million from \$0.9 million in the same period in 2007 largely due to higher management fees.

Management fees charged to G&A are based on the Company’s production profile, the fee increased from \$1.75 per producing boe to \$2.35 per boe effective April 1, 2008. The higher fee per boe combined with increases in production resulted in management fees increasing from \$0.4 million in 2007 to \$0.7 million in 2008. For additional information on management fees refer to the related party section of this MD&A.

SBC decreased by 29% in the current quarter as compared to the corresponding quarter in 2007 with an increase overall of 22% for the year ended December 31, 2008 as compared with 2007. The increase in SBC was the result of option holders exercising their options pursuant to the “cashless exercise” alternative wherein the option holder receives a cash payment equal to the difference between the exercise price and the market price multiplied by the number of options exercised in lieu of purchasing shares at the exercise price and the issuance of additional options in 2008.

G&A and SBC are expected to remain at approximately \$3.50 and \$1.00 per boe respectively in 2009.

Interest Expense

		Three Months Ended December 31			Year Ended December 31		
		2008	2007	Change	2008	2007	Change
Interest expense	\$m	127	107	19%	544	308	77%
Per boe	\$	1.50	1.75	(15%)	1.38	1.26	10%

Interest expense for the year ended December 31, 2008 was \$0.5 million compared to \$0.3 million for 2007.

Interest expense for the three months ended December 31, 2008 was \$0.1 million compared to \$0.1 million for 2007.

The increase in interest expense during 2008 is due to an increase in bank debt as a result of our ongoing drilling programs in 2007 and the first quarter of 2008.

The Company expects interest expense to decrease in 2009 due to lower interest rates and bank debt remaining at levels consistent with 2008.

Depletion, Depreciation and Accretion

		Three Months Ended December 31			Year Ended December 31		
		2008	2007	Change	2008	2007	Change
Depletion, depreciation and accretion	\$m	1,406	982	43%	5,507	4,261	29%
Per boe	\$	16.59	16.08	3%	13.94	17.43	(20%)

For the year ended December 31, 2008, depletion, depreciation and accretion ("DD&A") increased 29% from \$4.3 million in 2007 to \$5.5 million in 2008. The DD&A provision for the three months ended December 31, 2008 increased 43% from \$0.9 million to \$1.4 million. Both increases are due to increased production volumes and higher capital base in 2008 over 2007. On a per boe basis, the DD&A ratio decreased by 20% in 2008 due to reduced pro-rata capital expenditures relative to the reserve additions in the year.

The depletion, depreciation and accretion rate per boe for 2009 is expected to remain the same or trend downwards given the oil discoveries made in the Pembina, Alberta area. The Company will have a better indication of the impact of the Pembina oil discovery in the second quarter of 2009 when we receive an updated independent evaluation of our reserves.

Income Taxes

		Three Months Ended December 31		Year Ended December 31	
		2008	2007	2008	2007
Income Taxes	\$m	(84)	(38)	672	(251)

Future income taxes for the year ended December 31, 2008 were \$0.7 million compared to a reduction of \$0.3 million for 2007. The change is consistent with the transition from a loss to income before taxes.

At December 31, 2008, the Company had estimated resource tax pools and tax losses of approximately \$23 million. Ironhorse does not expect to be taxable in the next two years, given the forecasted level of capital expenditures and current commodity prices. As at December 31, 2008 Ironhorse had \$3.5 million

of Canadian exploration expenditures to be incurred prior to December 31, 2009, pursuant to a 2008 flow-through share offering.

Field Netback

<i>\$ Per boe</i>	Three Months Ended December 31		Year Ended December 31	
	2008	2007	2008	2007
Revenue	40.40	36.47	45.45	36.95
Less: Royalties	12.95	13.63	17.42	13.95
Operating expenses	3.08	4.29	2.29	3.32
Field netback	24.37	18.55	25.74	19.68

Ironhorse's field netback per boe for the year ended December 31, 2008 increased 31% to \$25.74 from \$19.68 per boe for the corresponding 2007 period.

For the quarter ended December 31 the field netback increased 31% from \$18.55 in 2007 to \$24.37 in 2008.

The higher field netbacks were a result of higher natural gas prices and lower operating expenses which were partially offset by increased royalties.

Field netbacks in 2009 are expected to be lower due to falling oil and gas commodity prices.

Funds from Operations and Earnings (Loss)

		Three Months Ended December 31			Year Ended December 31		
		2008	2007	Change	2008	2007	Change
Funds from operations	\$m	1,525	738	107%	8,001	3,529	127%
Basic per share	\$	0.07	0.03	133%	0.40	0.18	122%
Diluted per share	\$	0.07	0.03	133%	0.39	0.18	117%
Income (loss)	\$m	96	(262)		1,586	(812)	
Basic per share	\$	0.00	(0.01)		0.08	(0.04)	
Diluted per share	\$	0.00	(0.01)		0.08	(0.04)	
Weighted average shares outstanding							
Basic	m	21,779	19,488	12%	20,225	19,411	4%
Diluted	m	21,906	20,013	9%	20,352	20,034	2%

Funds from operations for the year ended December 31, 2008 increased 127% to \$8 million from \$3.5 million in 2007.

Funds from operations for the three months ended December 31, 2008 increased 107% to \$1.5 million from \$0.7 million in 2007.

The increase in funds from operations for both periods was due principally to increased natural gas production and higher natural gas prices.

Funds from operations were calculated as follows:

		Three Months Ended December 31		Year Ended December 31	
		2008	2007	2008	2007
Income (loss)	\$m	128	(262)	1,586	(812)
Add/(subtract):					
Depletion, depreciation and accretion	\$m	1,406	982	5,507	4,261
Stock-based compensation	\$m	86	56	264	357
Future income taxes	\$m	(84)	(38)	672	(251)
Abandonment costs incurred	\$m	(11)	-	(28)	(26)
Funds from operations	\$m	1,525	738	8,001	3,529

Capital Expenditures

Expenditure category	Three Months Ended December 31			Year Ended December 31		
	2008	2007	Change	2008	2007	Change
Land	230	(299)		1,434	1,532	(6%)
Seismic	49	22	123%	144	159	(9%)
Drilling and completions	1,215	674	80%	6,326	7,976	(21%)
Facilities, pipelines and equipment	1,321	1,396	(5%)	2,505	2,554	(2%)
G&A	27	44	(39%)	157	185	(15%)
	2,842	1,837	55%	10,566	12,406	(15%)

Area	Three Months Ended December 31			Year Ended December 31		
	2008	2007	Change	2008	2007	Change
Saskatchewan	2,302	1,767	30%	9,419	10,404	(9%)
NE British Columbia	341	24	1,321%	710	1,749	(59%)
Alberta	172	2	8,500%	280	68	312%
G&A	27	44	(39%)	157	185	(15%)
	2,842	1,837	55%	10,566	12,406	(15%)

Capital expenditures decreased 15% from \$12.4 million in 2007 to \$10.6 million in 2008 primarily as a result of the Company spending less in the Shackleton and NE British Columbia areas. In Shackleton the company achieved additional cost efficiencies with respect to drilling and infrastructure. In NE British Columbia the Company acquired land and seismic whereas in 2007 the Company participated in drilling a well.

Capital expenditures increased 55% from \$1.8 million to \$2.8 million for the three months ended December 31, 2008 as the Company undertook preparations for its 2008/2009 winter drilling program in the Shackleton, Saskatchewan and Pembina, Alberta areas.

Related Party Transactions

Ironhorse is party to a management services agreement with Grizzly Resources Ltd. ("GRL") a company related by virtue of common management. Pursuant to the terms of the agreement GRL provides technical and administrative services typically required in operating an oil and gas company. This arrangement has provided Ironhorse with the benefits of accessing a larger more comprehensive pool of technical and administrative services than it could otherwise afford during its early stage of development. The management contract charges Ironhorse a fee based on units of production and a percentage of

capital expenditures. The production fee is charged to G&A and is calculated on a producing boe basis. Effective April 1 2008, the fee per boe was increased from \$1.75 to \$2.35 per boe. The amount charged is reduced by all “monthly well operating overhead” charges. The fee on capital expenditures is capitalized to property and equipment. This fee was increased from three to four percent of the capital expenditures effective April 1 2008, and is reduced by all “capital overhead” charges which otherwise flow through the joint interest billings.

		Year Ended December 31	
		2008	2007
Production fees	\$m	729	354
Capital fees	\$m	156	185
Management fees	\$m	885	539

Normal Course Issuer Bid

On December 1, 2008 the Company reactivated its program to purchase its common shares from time to time in accordance with the normal course issuer bid procedures under Canadian securities law.

Pursuant to the terms of the current issuer bid, Ironhorse may purchase for cancellation, as Ironhorse considers advisable, up to a maximum of 1,493,459 common shares during the 12 month period commencing December 1, 2008. The purchases will be made on the open market through the TSX Venture Exchange. PI International Corp. is the brokerage firm conducting the normal course issuer bid on behalf of the Company.

Ironhorse believes that the purchase of its common shares will create shareholder value as recent market prices for its common shares do not always reflect the underlying value of its oil and gas reserves. To the extent that the Company is able to purchase shares on the open market for cancellation there is a proportionate increase in the value attributable to remaining outstanding common shares.

During the year ended December 31, 2008, the Company acquired 73,400 common shares at an average cost of \$1.03 per share. To date in 2009, the Company has acquired 92,700 common shares at an average cost of \$1.31 per share.

Liquidity and Capital Resources

Oil and gas exploration and development is a capital intensive business. Periodic infusions of additional capital may be required to accelerate the rate of the Company’s growth. Ironhorse chooses to finance its ongoing capital expenditure program through a combination of reinvesting funds from operations, bank borrowing and additional share equity.

The Company had drawn \$6.4 million against its \$14.5 million credit facility at December 31, 2008. The Company’s credit facility, reviewable semi-annually, is with a Canadian chartered bank. Advances bear interest at the bank’s prime lending rate plus 0.25% or at prevailing bankers’ acceptance rate plus an applicable bank fee. The loan is secured by all of the Company’s assets. Principal repayments are required only if the borrowing base is exceeded. Ironhorse expects to receive a favourable review of its credit facility as increases in the Company’s proven producing reserves should more than offset lower commodity prices.

The Company believes it can finance its planned 2009 capital expenditures from funds from operations and existing credit facilities. The priorities for 2009 include:

- Drilling and placing on production 32 (16 net) gas wells in Shackleton, which was completed in the first quarter of 2009;
- Placing the Pembina oil discoveries which were drilled in the first quarter of 2009 on production in the fourth quarter of 2009 and
- Fulfilling our remaining exploration flow-through expenditure commitments which are estimated at \$2.2 million

Ironhorse believes it can complete these activities with its current financial resources. However if natural gas prices were to decrease significantly from current levels for a sustained period of time, this may impact the timing of the above activities. See "Impact of Current Economic Volatility and Uncertainty"

Ironhorse has 21,816,043 common shares and 2,061,500 stock options with a weighted average exercise price of \$1.48 per share outstanding as at March 16, 2009.

Contractual Obligations

Ironhorse has various contractual obligations and commitments arising in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

The Company issued flow-through common shares in 2007 and 2008. Pursuant to the terms of the financings, the Company is obligated to spend the gross proceeds on qualifying Canadian exploration and development expenditures. As at December 31, 2008, Ironhorse had obligations to incur \$3.5 million of Canadian exploration expenditures in 2009 to fulfill all of its flow-through financing obligations. As of today's date we estimate that the Company has incurred approximately \$1.2 million of qualifying expenditures in 2009 leaving a balance of \$2.2 million of qualifying expenditures to be incurred through out the balance of 2009.

Critical Accounting Estimates

The preparation of the Company's financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported financial results of the Company. On an on-going basis, management reviews its estimates in light of currently available information. Changes in facts and circumstances may require revisions to estimates causing changes to reported results. Ironhorse's critical accounting estimates are discussed below.

Oil and Gas Accounting

Ironhorse follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. By their inclusion in the unit-of-production calculation, reserve estimates are a significant component of the calculation of depletion and depreciation expense.

Independent engineers engaged by the Company use all available geological, reservoir, and production performance data to prepare the reserve estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, commodity prices, economic conditions, government regulations and other relevant factors. If reserve estimates are revised downward, net income could be affected by increased depletion and depreciation.

Impairment of Petroleum and Natural Gas Assets

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform an impairment test (the “ceiling test”) that calculates a limit for the net carrying cost of petroleum and natural gas assets. The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test. The ceiling test is a two-stage process. The first stage of the test is a recovery test which compares the undiscounted future cash flows from proved reserves at forecast prices plus the cost, less impairment, of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flows. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flows from proved plus probable reserves at the forecast prices. If reserve estimates are revised downward, net income could be affected by any additional depletion and depreciation recorded under the ceiling test calculation and could result in a significant accounting expense for a particular period. Ironhorse had approximately a \$24 million cushion pursuant to the first test at December 31, 2008.

Asset Retirement Obligations

The amounts recorded for asset retirement obligations are estimated based on the Company’s net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the financial statements of future periods.

Changes in Accounting Policies

Effective January 1, 2008, the Company adopted the Canadian Institute of Chartered Accountants (CICA) recommendations for capital disclosures which require disclosure of qualitative and quantitative information regarding the Company’s objectives, policies and processes for managing capital (refer to Note 10 to the financial statements).

Effective January 1, 2008, the Company adopted the CICA recommendations pertaining to disclosure and presentation of financial instruments which require disclosure of the classification of the Company’s financial instruments and additional qualitative and quantitative information regarding the nature and extent of risks arising from financial instruments to which the Company is exposed (refer to Note 11 to the financial statements).

Financial Instruments

Ironhorse’s financial instruments consist of cash, accounts receivable and accounts payable, accrued liabilities and bank loan payable. Unless otherwise noted, it is management’s opinion that the Company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair value of these financial instruments is their carrying value due to their short-term maturity and capacity for prompt liquidation.

IFRS Changeover Plan

The conversion to IFRS, effective January 1, 2011, represents a one-time implementation of multiple accounting standards which differ significantly from Canadian GAAP. The scope of the conversion project extends beyond accounting issues as it will need to also address changes to information systems, internal controls over financial reporting and disclosure controls and procedures and related business issues such as terms of contracts affected by accounting measures. Ironhorse has initiated a conversion plan which will take the Company through the various decisions and milestones which need to be addressed over the next two years to ensure an orderly conversion to IFRS. To assist in communicating what needs to be done and what has been done the Company will provide updates in its MD&A over the next two years with respect to its conversion plan

Key Activity - selected elements only	Milestones/Deadlines	Effort Accomplished by December 31, 2008
<u>Financial Statement Preparation</u>		
Identify differences between Canadian GAAP and IFRS accounting policies	Ready for commencement of 2010 financial year	Significant accounting policy choices identified
Choose IFRS policies.	Quantification of effects of change for IFRS 1 disclosure and comparative 2010 financial statements including note disclosure by end of Q3 2010	Internal committee comprised of senior personnel meeting weekly
Identify additional IFRS disclosure requirements		
Develop financial statement format		
Assess impact and tax and regulatory reporting		
Quantifications of IFRS 1 disclosures for 2010		
<u>Systems and Processes</u>		
Develop new chart of accounts	Ready for conversion beginning of Q4 2009	Expert resources/training program commenced
IFRS expertise identification and development at all levels including board level	Ready for parallel processing of general ledger before 2010	Ongoing discussions with accounting systems provider
Map accounts to GAAP basis to IFRS basis		
Identify how to reconcile back to GAAP for transition year 2010		
Document IFRS processes		
<u>Investor Relations / Stakeholder Communications</u>		
Educate analysts, investors and employees on the impact of IFRS	Communicate significance and impact of changes as they become know	Quarterly updates in the MD&A

Selected Quarterly Information

	Unit	2008				2007			
		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial									
Revenue	\$m	3,427	4,355	6,120	4,063	2,227	2,169	3,121	1,524
Funds from operations	\$m	1,525	1,806	2,939	1,731	738	894	1,325	572
Per share – basic	\$	0.07	0.09	0.15	0.09	0.04	0.05	0.08	0.03
Per share – diluted	\$	0.07	0.09	0.14	0.09	0.04	0.04	0.07	0.03
Income (loss)	\$m	128	227	919	312	(263)	(253)	(115)	(181)
Per share – basic	\$	0.00	0.01	0.05	0.02	(0.01)	(0.01)	(0.01)	(0.01)
Per share – diluted	\$	0.00	0.01	0.05	0.02	(0.01)	(0.01)	(0.01)	(0.01)
Capital expenditures	\$m	2,842	366	1,416	5,942	1,836	244	369	9,957
Net debt	\$m	6,789	8,645	10,023	12,205	7,983	7,231	7,333	7,966
Total assets	\$m	32,199	31,070	32,600	32,098	25,271	26,016	27,108	25,843
Operational									
Production									
Natural gas	mcf/d	5,486	6,624	7,600	6,034	3,935	4,428	5,030	2,494
Light oil & Ngls	bbls/d	7	7	7	6	8	10	6	5
Total sales	boe/d	921	1,111	1,143	1,012	664	748	844	421
Average price									
Natural gas	\$/mcf	6.72	6.99	8.74	7.29	6.11	5.16	6.74	6.64
Light oil & Ngls	\$/bbl	54.41	114.82	103.61	102.61	74.11	73.68	68.84	58.54
Boe	\$/boe	40.41	42.61	52.80	44.13	36.47	31.53	40.62	40.06
Field Netback	\$/boe	24.37	24.95	29.28	23.50	18.56	18.24	22.11	19.16
Weighted average shares outstanding									
Basic	m	21,780	20,111	19,979	19,500	19,488	19,557	19,705	18,886
Diluted	m	21,906	20,489	20,376	19,509	20,013	20,112	20,316	19,548

Ironhorse's fourth quarter 2008 growth in revenue, funds from operations and net income is primarily attributable to the successful first quarter drilling program and higher natural gas prices. First quarter 2009 operating results are expected to reflect increased gas production as a result of wells drilled and placed on production and be offset by lower natural gas prices. During the first quarter of 2009 the Company also drilled two successful Nisku oil wells at Pembina, Alberta which we plan to place on production early in the fourth quarter of 2009.

The Company's operating results over the past eight quarters reflect the ongoing development of its shallow gas project in Shakleton, Saskatchewan which has resulted in increased production, revenues and cash flow from operations.

ADDITIONAL INFORMATION

Additional information regarding Ironhorse Oil & Gas Inc., including the Company's Annual Information Form, is available on SEDAR at www.sedar.com or on the Company's website at www.ihorse.ca.