



**ANNUAL INFORMATION FORM**

**FOR THE YEAR ENDED**

**DECEMBER 31, 2008**

**March 18, 2009**

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## ABBREVIATIONS

### Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
BOE/d	barrel of oil equivalent per day
NGLs	natural gas liquids
STB	standard tank barrels

### Natural Gas

Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
MM	Million
M	Thousand

### Other

AECO	A natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
m <sup>3</sup>	cubic metres
MBOE	1,000 barrels of oil equivalent
M\$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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

## CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Thousand cubic metres	Mcf	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

## CERTAIN DEFINITIONS

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

"**ABCA**" means *Business Corporations Act* (Alberta);

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

"**Common Shares**" means the common shares in the capital of Ironhorse;

"**Ironhorse**" or the "**Company**" means Ironhorse Oil & Gas Inc., a corporation continued pursuant to the ABCA and includes its predecessors where the context so requires;

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

"**GLJ Report**" means the report of GLJ dated February 11, 2009 evaluating Ironhorse's crude oil, natural gas liquids and natural gas reserves as at December 31, 2008;

"**Gross**" means:

- (a) in relation to the Company's interest in production and reserves, the Company's working interest share (operated and non-operated) before deduction of royalties and without including any of the Company's royalty interests in production or reserves;
- (b) in relation to wells, the number of wells in which the Company has an interest; and
- (c) in relation to the Company's interest in a property, the total area in which the Company has an interest.

"**Income Tax Act**" or "**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1. (5th Supp), as amended, including the regulations promulgated there under;

"**Net**" means:

- (a) in relation to the Company's interest in production and reserves, the Company's working interest share (operated and non-operated) after deduction of royalties plus the Company's royalty interest in production or reserves;
- (b) in relation to wells, the number of wells in which the Company has an interest obtained by aggregating the Company's working interest in each of the Company's gross wells; and
- (c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest the Company owns.

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

"**NRF**" means the New Royalty Framework announced by the Alberta government on October 25, 2007;

"**Shareholders**" means the holders of Common Shares; and

"**TSX-V**" or the "**Exchange**" means the TSX Venture Exchange.

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Company's most recently completed financial year, being December 31, 2008.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

## FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

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

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

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

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

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

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

## CORPORATE STRUCTURE

### Name, Address and Incorporation

Ironhorse was originally incorporated as Keywest Resources Ltd. (N.P.L.) under the *Companies Act* (British Columbia) as a Specially Limited Company on September 18, 1972. On November 26, 2002 the Company was continued from British Columbia to Alberta. On June 27, 2003, the Company acquired its first oil and gas properties in the Boundary

Lake and Lochend areas of Alberta, commencing its oil and gas operations and on May 13, 2004, the Company changed its name to Ironhorse Oil & Gas Inc.

Ironhorse's head and registered office is located at 1000, 324 - 8th Avenue SW, Calgary, Alberta T2P 2Z2.

The Common Shares trade on the TSX-V under the symbol "IOG".

### **Inter-Corporate Relationships**

Ironhorse does not have any subsidiaries as at March 18, 2009.

## **GENERAL DEVELOPMENT OF THE COMPANY'S BUSINESS**

Ironhorse is a Calgary based company engaged in the exploration, development, acquisition and production of oil and gas reserves in western Canada primarily in the provinces of British Columbia, Alberta and Saskatchewan.

### **Three Year History**

#### **2006**

In the year ended December 31, 2006, the Company raised \$5.1 million through the issuance of 1,400,000 Common Shares at a price of \$2.25 per share and 700,000 Common Shares issued on a "flow-through" basis at a price of \$2.75 per share.

Ironhorse acquired a 50% working interest in the shallow gas development project in the Shackleton, Saskatchewan area. The Company commenced field operations in the first quarter of 2006 with the drilling and placing on production of 7 (3.5 net) gas wells. The Shackleton area is an environmentally sensitive area where drilling and completion activities are limited to late December to early March. The Company also drilled one (0.2 net) dry well at Pembina, Alberta during the year ended December 31, 2006.

#### **2007**

In January 2007, the Company raised \$5.8 million through the issuance of 1,812,500 Common Shares at a price of \$2.00 per share and 906,250 Common Shares issued on a "flow-through" basis at a price of \$2.40 per share.

Funds from operations and proceeds from the share equity issue, together with advances of \$5.1 million under the Company's bank credit facilities, funded Ironhorse's \$12.4 million capital investment program in 2007.

During the year, the Company continued to develop its Shackleton, Saskatchewan property. The Company drilled 32 (16 net) gas wells in the Shackleton area of which 30 (15 net) were placed on production bringing the total number of producing gas wells to 37 (18.5 net) the other two gas wells were placed on production in the following year. The Company also drilled one (0.5 net) dry well at Kotcho, British Columbia during the year.

During the year, the Company acquired for cancellation, 341,000 Common Shares at an average price of \$1.60 per share pursuant to the terms of its normal course issuer bid.

#### **2008**

On May 12, 2008 the Company completed a non-brokered private placement financing, to certain officers of the Company, for aggregate gross proceeds of \$0.6 million comprised of 200,000 Common Shares at a price of \$1.50 per share and 200,000 Common Shares issued on a "flow-through" basis at a price of \$1.60 per share.

On October 23, 2008 the Company completed a brokered private placement financing for aggregate gross proceeds of \$3.5 million consisting of 1,683,000 Common Shares issued on a "flow-through" basis at a price of \$2.08 per share.

Funds from operations together with proceeds from the private placements noted above financed a \$10.5 million capital investment program in 2008.

During the year the Company continued to develop its Shackleton property where an additional 30 (15 net) gas wells were drilled and 31 (15.5 net) gas wells were placed on production by year end bringing the total number of producing gas well to 68 (34 net).

During the year ended December 31, 2008 the Company acquired for cancellation 73,400 Common Shares at an average price of \$1.13 per share pursuant to the terms of its normal course issuer bid (see "*Normal Course Issuer Bid*").

### **Subsequent Events**

To date, in the first quarter of 2009 the Company has drilled 31 (15.5 net) gas wells and placed 32 (16 net) gas wells on production in the Shackleton area bringing the total number of producing wells to 100 (50 net) and in the Pembina area the Company has drilled two (0.4 net) Nisku oil wells.

## **SIGNIFICANT ACQUISITIONS**

Ironhorse has not completed any significant acquisitions during its most recently completed financial year for which disclosure would be required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

## **DESCRIPTION OF THE BUSINESS**

### **General**

The Company is engaged in the exploration for and development and production of crude oil and natural gas in western Canada. Ironhorse has three core areas of operation located at, Shackleton Saskatchewan, Pembina, Alberta and in north east British Columbia. The Company is participating in the development of a significant shallow gas play at Shackleton. Primary development of the Shackleton property was completed in the first quarter of 2009, wherein the Company has a 50% working interest in 100 producing gas wells which represents a drilling density of "one well per quarter section". The Company is evaluating increasing the drilling density in future years. The timing of this development will vary with gas prices, royalties and drilling costs. At Pembina, Ironhorse's main focus is the exploration of light sour oil in one of the most prolific oil trends in Alberta. In the first quarter of 2009 the Company drilled two (0.4 net) Nisku oil wells. In the Company's most recently acquired core area, north east British Columbia, Ironhorse is exploring the Bluesky, Gething and Montney formations for natural gas.

### **Business Plan and Growth Strategy**

The business plan of the Company is to create profitable per share 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.

### **Joint Ventures**

All of Ironhorse's operations involve joint ventures with other industry partners. In addition, Ironhorse relies on Grizzly Resources Ltd. to provide the Company with certain management technical and administrative services.

### **Economic Dependence**

In 2008, Ironhorse produced over 90% of its production from its Shackleton shallow gas property, located in southwestern Saskatchewan. The Company relies on the continued performance of this area to contribute to its future operational success.

## **Safety and Environment Protection**

The Company has made a firm commitment to the safety of its staff and contractors and to the general public, and the protection of the environment affected by its operations. Ironhorse tailors its operational efforts to safely engage resource extraction, with sensitivity to the environment and the needs of the communities in which it operates. The commitment to safety is for the protection of the Company's staff, its contractors and the residents in proximity to the Company's oil and natural gas properties. Federal, provincial and local governments have enacted laws concerning the discharge of materials into the environment and otherwise relating to environmental protection. It is the responsibility of all of the Company's personnel to ensure that all operations are conducted in accordance with corporate policies that meet or exceed occupational health and safety laws and regulations. Ironhorse is committed to maintaining this standard of operations.

## **Competitive Conditions**

The oil and natural gas industry is intensely competitive in all its phases. Ironhorse competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Ironhorse's competitors include resource companies which have greater financial resources, staff and facilities than those of Ironhorse. Competitive factors in the distribution and marketing of oil and natural gas include pricing, and methods and reliability of delivery. Ironhorse believes that its competitive position is equivalent to or better than that of other oil and gas issuers of similar size and at a similar stage of development.

## **STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION**

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated February 11, 2009. The effective date of the Statement is December 31, 2008 and the preparation date of the Statement is January 15, 2009. The Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 and the Report on Reserves Data by February 11, on Form 51-102F2 are attached as Schedules "A" and "B" to this Annual Information Form.

### **Disclosure of Reserves Data**

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ with an effective date of December 31, 2008 contained in the GLJ Report. The Reserves Data summarizes the oil, liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. See "*Notes to Reserves Data Tables*" below. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Company engaged GLJ to provide an evaluation of proved and proved plus probable reserves. All of the Company's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

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

## Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue

### RESERVES SUMMARY

Reserves Category	Light and Medium Oil		Natural Gas		Total Oil Equivalent	
	Company Gross (Mbbbl)	Company Net (Mbbbl)	Company Gross (MMcfe)	Company Net (MMcfe)	Company Gross (Mbbbl)	Company Net (Mbbbl)
Proved						
Developed Producing	17	13	7,472	5,700	1,263	964
Developed Non-Producing	0	0	882	715	147	119
Undeveloped	0	0	4,571	3,473	762	579
<b>Total Proved</b>	<b>17</b>	<b>13</b>	<b>12,925</b>	<b>9,888</b>	<b>2,172</b>	<b>1,662</b>
Probable	5	4	12,320	9,756	2,058	1,629
<b>Total Proved Plus Probable</b>	<b>22</b>	<b>17</b>	<b>25,245</b>	<b>19,644</b>	<b>4,230</b>	<b>3,291</b>

### NET PRESENT VALUE SUMMARY

Reserves Category	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	\$/boe	\$/Mcfe
Proved							
Producing	35,033	29,512	25,486	22,458	20,116	26.45	4.41
Developed Non - Producing	4,191	2,371	1,365	789	450	11.46	1.91
Undeveloped	16,958	11,269	7,812	5,572	4,038	13.50	2.25
<b>Total Proved</b>	<b>56,182</b>	<b>43,152</b>	<b>34,663</b>	<b>28,819</b>	<b>24,604</b>	<b>20.86</b>	<b>3.48</b>
Total Probable	50,412	25,532	14,021	8,048	4,653	8.60	1.43
<b>Total Proved Plus Probable</b>	<b>106,594</b>	<b>68,684</b>	<b>48,684</b>	<b>36,867</b>	<b>29,257</b>	<b>14.79</b>	<b>2.47</b>

Reserves Category	Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)				
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)
Proved					
Producing	30,402	25,691	22,246	19,649	17,637
Developed Non-Producing	3,166	1,776	1,009	572	316
Undeveloped	12,297	7,925	5,243	3,495	2,293
<b>Total Proved</b>	<b>45,865</b>	<b>35,392</b>	<b>28,498</b>	<b>23,716</b>	<b>20,246</b>
Total Probable	36,520	18,014	9,308	4,770	2,201
<b>Total Proved Plus Probable</b>	<b>82,385</b>	<b>53,406</b>	<b>37,806</b>	<b>28,486</b>	<b>22,447</b>

**FUTURE NET REVENUE BY PRODUCTION GROUP AS OF DECEMBER 31, 2008  
FORECAST PRICES AND COSTS**

	<b>Future Net Revenue Before Income Taxes (discounted at 10%/year)</b>		
	M\$	\$/boe	\$/Mcf
Proved Producing			
Light & Medium Oil	613	32.29	5.38
Natural Gas	24,873	26.33	4.39
<b>Total: Proved Producing</b>	<b>25,486</b>	<b>26.45</b>	<b>4.41</b>
Total Proved			
Light & Medium Oil	613	32.29	5.38
Natural Gas	34,050	20.73	3.46
<b>Total: Total Proved</b>	<b>34,663</b>	<b>20.86</b>	<b>3.48</b>
Total Proved Plus Probable			
Light & Medium Oil	717	29.67	4.95
Natural Gas	47,967	14.68	2.45
<b>Total: Proved Plus Probable</b>	<b>48,684</b>	<b>14.79</b>	<b>2.47</b>

**Notes to Reserves Data Tables:**

1. Columns may not add due to rounding.
2. The crude oil and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

*Reserve Categories*

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

- (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

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

- (a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
  - (i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
  - (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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

#### *Levels of Certainty for Reported Reserves*

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

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

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

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

### 3. Forecast Prices and Costs

Forecast prices and costs are those:

- (a) generally acceptable as being a reasonable outlook of the future; and
- (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Report were GLJ's forecasts as at January 1, 2009, which were as follows:

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS  
FORECAST PRICES AND COSTS**

Year	Oil		Natural Gas		Inflation %/Year	Exchange Rate (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40° API (\$Cdn/Bbl)	AECO Natural Gas Spot Price (\$Cdn/MMBtu)			
2009	57.50	68.61	7.58		2.0	0.825
2010	68.00	78.94	7.94		2.0	0.850
2011	74.00	83.54	8.34		2.0	0.875
2012	85.00	90.92	8.70		2.0	0.925
2013	92.01	95.91	8.95		2.0	0.950
2014	93.85	97.84	9.14		2.0	0.950
2015	95.73	99.82	9.34		2.0	0.950
2016	97.64	101.83	9.54		2.0	0.950
2017	99.59	103.89	9.75		2.0	0.950
2018	101.59	105.99	9.95		2.0	0.950
2019+	+2.0%/yr	+2.0%/yr	+2.0%/yr		2.0	0.950

Weighted average historical prices realized by the Company for the year ended December 31, 2008, were \$7.52/Mcf for natural gas and \$67.00/Bbl for crude oil.

*Notes:*

1. Estimated future abandonment costs related to a property have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities
2. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

## RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE

The following table sets out the reconciliation of the Company's gross reserves as at December 31, 2007 compared to December 31, 2008 based on forecast prices and costs by principal product type:

Factors	Light and Medium Oil			Conventional Natural Gas			Boe		
	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2007	19	6	25	11,312	3,616	14,928	1,905	608	2,513
Discoveries	0	0	0	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0	0	0	0
Infill									
Drilling*	0	0	0	3,452	6,312	9,764	575	1,052	1,627
Improved Recovery*	0	0	0	0	0	0	0	0	0
Technical Revisions	0	(1)	(0)	505	2,392	2,897	84	398	482
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0
Production	(3)	0	(3)	(2,344)	0	(2,344)	(393)	0	(393)
December 31, 2008	17	5	22	12,925	12,320	25,245	2,171	2,058	4,229

*Note:*

\* The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".

## COMPANY GROSS RESERVES FIRST ATTRIBUTED by YEAR

### Undeveloped Reserves

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

### Proved Undeveloped Reserves

	Light and Medium Oil (Mbbbl)		Natural Gas (MMcf)		Oil Equivalent (Mbbbl)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	-	-	-	-	-	-
2006	-	-	4151	4151	690	192
2007	-	-	5098	5729	850	955
2008	-	-	3825	4571	638	762

## Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Natural Gas (MMcf)		Oil Equivalent (Mbbl)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	-	-	-	-	-	-
2006	-	-	1325	1325	221	221
2007	-	-	1515	1776	253	296
2008	-	-	6807	7397	1,135	1,233

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The majority of the proven undeveloped reserves are expected to be developed within the next year and majority of the probable undeveloped reserves are expected to be developed within the next four years of the effective date of the GLJ Report.

In the first quarter of 2009 the Company developed and placed on production the majority of its proved undeveloped reserves.

The Company plans to develop the majority of its probable undeveloped reserves over the next four years. The actual timing of the development of the probable undeveloped reserves will vary with gas prices and development costs.

### *Significant Factors or Uncertainties*

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The current economic volatility and uncertainty could result in gas prices remaining at current or lower levels which would impact the timing of the development of the undeveloped probable reserves.

### *Future Development Costs*

The following table sets forth the development costs deducted in the estimation of the Company's future development costs attributable to the reserve categories noted below:

Year	Annual Capital Expenditures	
	Proved Reserves M\$	Proved Plus Probable Reserves M\$
2009	7,788	7,992
2010	-	8,114
2011	-	8,202
2012	265	5,336
2013	-	
2014+	469	870
<b>Total</b>	<b>8,609</b>	<b>30,512</b>
<b>10% Discounted</b>	<b>7,936</b>	<b>25,347</b>

The Company expects to have sufficient internally generated funds from operations and/or available bank credit facilities to finance the future development costs noted above.

## Other Oil and Gas Information

### *Principal Properties*

The following is a description of Ironhorse's oil and natural gas properties. Information in respect of production volumes is expressed as "gross" production, namely the total of Ironhorse's working interest share of production, before deduction of royalties owned by others and without including any royalty interests of the Company. Reserve amounts are stated, before deduction of royalties, based on future cost and price assumptions as evaluated, as at December 31, 2008 in the GLJ Report. Based on the estimated net present value of future net revenue, before income taxes and discounted at 10% per annum, GLJ evaluated 100 percent of Ironhorse's total proved and probable reserves. Information in respect of gross and net acres, well counts and production are as of December 31, 2008, except where indicated otherwise.

### **Pembina, Alberta**

The Company's Pembina property is located in approximately 30 miles west of Edmonton, Alberta. Ironhorse holds working interests ranging from 6.9% to 18.75% on 10,240 acres in the area. In the first quarter of 2009, the Company drilled two (0.4 net) Nisku oil wells. The Company is proceeding with plans to complete and place the wells on production later this year.

### **Shackleton, Saskatchewan**

The Shackleton property is located in Townships 21 and 22, Ranges 18 to 20, W3, near Abbey, Saskatchewan. The Company holds a 50% working interest in 16,311 acres in the area. The property is currently producing natural gas from the Milk River formation. Currently, the Company has a 50% working interest in 100 producing natural gas wells (2008 – 68 wells) and property infrastructure including a gas plant and gathering system. In 2008, the Shackleton property produced 2,290 MMcf of natural gas (2007 – 1,434 MMcf). Shackleton accounts for 97.3% of the Company's reserves at December 31, 2008, as reported by GLJ Petroleum Consultants.

## Oil and Gas Wells

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

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	15	1.4	7	0.6	-	-	-	-
Saskatchewan	-	-	-	-	68	32	1	0.5
<b>Total</b>	<b>15</b>	<b>1.4</b>	<b>7</b>	<b>0.6</b>	<b>68</b>	<b>32</b>	<b>1</b>	<b>0.5</b>

## Land Holdings (including Properties with No Attributable Reserves)

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

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
British Columbia	-	-	3,975	297	3,975	297
Alberta	2,715	257	12,160	1,585	14,875	1,842
Saskatchewan	11,192	5,558	5,119	2,560	16,311	8,118
<b>Total</b>	<b>13,907</b>	<b>5,815</b>	<b>21,254</b>	<b>4,442</b>	<b>35,161</b>	<b>10,257</b>

The Company expects that rights to explore and develop 1,085 net acres of the Company's undeveloped land holdings may expire by December 31, 2009.

The Company does not have any work commitments associated with its undeveloped lands.

## Hedging

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 has entered into a fixed price natural gas sales contract for 2000 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 summer 2009 covering April 1 to October 31, 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.

### ***Additional Information Concerning Abandonment and Reclamation Costs***

The Company estimates abandonment and site restoration costs on a site-by-site basis taking into account engineering studies, historical experience and industry guidelines. The Company expects to incur abandonment and site restoration costs for its net share of 91 wells and certain facilities that the Company has a working interest ownership. The total abandonment and site restoration costs, net of salvage values, is estimated by the Company at \$2.2 million, of which nil, \$81 thousand, and \$7 thousand are estimated to be incurred in 2009, 2010 and 2011, respectively. The GLJ Report deducted estimated costs to abandon existing and future reserves wells in the estimate of future net revenue but did not consider costs for site reclamation or abandonment of non-reserves wells and pipelines. In the determination of future net revenue associated with the total proved plus probable reserves, GLJ estimated well abandonment costs of \$1.2 million for proved reserves (\$161 thousand when discounted at 10%), and \$2.9 million for proved plus probable reserves (\$146 thousand when discounted at 10%), of which nil, \$2 thousand and \$2 thousand is to be incurred in 2009, 2010 and 2011, respectively.

### ***Tax Horizon***

The Company was not required to pay income taxes for the year ended December 31, 2008. The Company, based on the GLJ Report, does not expect to become taxable in 2009 or 2010.

### ***Capital Expenditures***

The following table summarizes capital expenditures related to the Company's properties for the year ended December 31, 2008:

<b>Capital Expenditures</b>	<b>\$Ms</b>
Property acquisition costs	
Proved properties	937
Undeveloped properties	494
Exploration costs	485
Development costs	8,650
Dispositions	-
<b>Total</b>	<b>10,566</b>

### ***Exploration and Development Activities***

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

	<b>Exploratory Wells</b>		<b>Development Wells</b>	
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>
Light and Medium Oil	-	-	-	-
Natural Gas	-	-	30	15
Service	-	-	-	-
Dry	-	-	-	-
<b>Total</b>	<b>-</b>	<b>-</b>	<b>30</b>	<b>15</b>

The Company has an extensive capital program of \$12 million planned for 2009. The primary components of this program are as follows:

<b>Expenditure</b>	<b>\$ MM</b>
Shackleton drilling, completing and tie-in of 32 (16 net) wells	5.0
Pembina drill and complete of 2 (0.4 net) wells	1.6
Pembina equip and tie-in of 2(0.4 net) wells	2.5
Pembina pressure maintenance	0.7
Flow-through exploration expenditures	2.2
<b>Total</b>	<b>12.0</b>

The Company's capital program is subject to variation throughout the year and there is no assurance that all or any part of the capital program will be expended as set forth above aside from those activities undertaken in the first quarter of 2009. In addition, capital expenditures may be made on the acquisition of undeveloped lands or oil and natural gas reserves as opportunity arises.

### *Production Estimates*

The following table sets out the volume of the Company's production estimated for the year ended December 31, 2009, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*" above.

Reserves Category	Light And Medium Oil		Conventional Natural Gas		Oil Equivalent	
	Company Gross (Bbl/d)	Company Net (Bbl/d)	Company Gross (Mcf/d)	Company Net (Mcf/d)	Company Gross (Bbl/d)	Company Net (Bbl/d)
Proved Producing						
Shackleton	0	0	4,583	34	764	511
Other Properties	7	5	45	3,067	14	11
<b>Total: Proved Producing</b>	<b>7</b>	<b>5</b>	<b>4,628</b>	<b>3,101</b>	<b>778</b>	<b>522</b>
Prove Developed Nonproducing						
Shackleton	0	0	(4)	(4)	(1)	0
Other Properties	0	0	0	0	0	0
<b>Total: Proved Developed Nonproducing</b>	<b>0</b>	<b>0</b>	<b>(4)</b>	<b>(2)</b>	<b>(1)</b>	<b>0</b>
Proved Undeveloped						
Shackleton	0	0	2,060	1,321	343	220
Other Properties	0	0	0	0	0	0
<b>Total: Proved Undeveloped</b>	<b>0</b>	<b>0</b>	<b>2,060</b>	<b>1,321</b>	<b>343</b>	<b>220</b>
Total Proved						
Shackleton	0	0	6,639	4,386	1,106	731
Other Properties	7	5	45	34	14	11
<b>Total: Total Proved</b>	<b>7</b>	<b>5</b>	<b>6,684</b>	<b>4,420</b>	<b>1,120</b>	<b>742</b>
Total Probable						
Shackleton	0	0	308	149	51	25
Other Properties	0	0	0	0	0	0
<b>Total: Total Probable</b>	<b>0</b>	<b>0</b>	<b>308</b>	<b>149</b>	<b>51</b>	<b>25</b>
Total Proved Plus Probable						
Shackleton	0	0	6,947	4,535	1,158	756
Other Properties	7	5	46	34	14	11
<b>Total: Total Proved Plus Probable</b>	<b>7</b>	<b>5</b>	<b>6,993</b>	<b>4,569</b>	<b>1172</b>	<b>767</b>

## Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback associated with the Company's assets for the three month periods ended as indicated below:

	2008			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production <sup>(1)</sup>				
Light and Medium Crude Oil (Bbls/d)	7	7	7	6
Conventional Gas (Mcf/d)	5,486	6,624	7,600	6,034
Combined (BOE/d)	921	1,111	1,143	1,012
Average Price Received				
Light and Medium Crude Oil (\$/Bbl)	54.41	114.82	103.61	102.61
Conventional Gas (\$/Mcf)	6.72	6.99	8.74	7.29
Combined (\$/BOE)	40.40	42.61	52.80	44.13
Royalties Paid				
Light and Medium Crude Oil (\$/Bbl)	9.06	22.88	19.62	28.95
Conventional Gas (\$/Mcf)	2.16	2.53	3.68	3.01
Combined (\$/BOE)	12.95	15.24	22.07	18.12
Operating Expenses				
Light and Medium Crude Oil (\$/Bbls)	18.68	23.24	21.68	14.70
Conventional Gas (\$/Mcf)	0.49	0.38	0.22	0.40
Combined (\$/BOE)	3.08	2.42	1.45	2.47
Netback Received (\$/BOE) <sup>(2)</sup>				
Light and Medium Crude Oil (\$/Bbls)	26.67	72.72	62.31	58.95
Conventional Gas (\$/Mcf)	4.06	4.09	4.84	3.88
Combined (\$/BOE)	24.37	24.95	29.28	23.50

### Notes:

- (1) Before deduction of royalties.
- (2) Netbacks are calculated by subtracting royalties and operating expenses from revenues.

The following table indicates average daily gross production from important fields in respect of the Company's assets for the year ended December 31, 2008:

	Light and Medium Crude Oil	Conventional Gas	Boe
	(Bbls/d)	(Mcf/d)	(BOE/d)
Other	7	50	15
Total Alberta	7	50	15
Shackleton	-	6,384	1,064
Total Saskatchewan	-	6,384	1,064
<b>Total</b>	<b>7</b>	<b>6,434</b>	<b>1,079</b>

For the twelve months ended December 31, 2008, approximately 94% of gross revenue from the Company's assets was derived from natural gas production and 6% was derived from crude oil production.

## DIVIDEND POLICY

The Company has not paid any dividends on its Common Shares to the date hereof. It is the present policy of the board of directors of the Company to retain any earnings to finance the growth and development of the Company's business and, therefore, the Company does not anticipate paying any dividends in the immediate future.

## NORMAL COURSE ISSUER BID

On December 1, 2008, the Company commenced a normal course issuer bid (the "Normal Course Issuer Bid") for the repurchase by the Company of up to 1,493,459 Common Shares through the facilities of the TSX-V. As of March 16, 2009 the Company had acquired 92,700 Common Shares at an average price of \$1.31 for an aggregate cost of \$121,437. The Normal Course Issuer Bid expires on December 1, 2009. Shareholders may obtain a copy of the notice filed with the TSX-V in respect of the Normal Course Issuer Bid, without charge, upon written request to the Company at Suite 1000, 324 - 8th Avenue SW, Calgary, Alberta T2P 2Z2, Attention: Vice-President, Finance and Chief Financial Officer.

## DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of the Company consists of an unlimited number of Common Shares and an unlimited number of first preferred shares. As of March 16, 2009 there were 21,816,043 Common Shares issued and outstanding and no first preferred shares issued and outstanding.

### Common Shares

The Common Shares are entitled to one (1) vote per share at meetings of shareholders, to dividends in such amounts as the directors may from time to time declare and, in the event of liquidation, dissolution or winding-up of the Company, are entitled to share pro rata in the assets of the Company.

### First Preferred Shares

The first preferred shares rank in priority to the Common Shares as to the payment of dividends and as to the distribution of assets in the event of liquidation, dissolution or winding-up of the Company. The first preferred shares may also be given such other preferences over the Common Shares as may be determined for any series authorized to be issued. The Company currently has no first preferred shares outstanding.

## MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX-V under the symbols "IOG". The following sets forth trading information for the Common Shares for the periods indicated, as quoted by the Exchange:

<u>Period</u>	<u>High</u>	<u>Low</u>	<u>Volume</u>
<b><u>2008</u></b>			
January	1.33	1.16	66,763
February	1.45	1.30	63,403
March	1.40	1.30	79,586
April	1.85	1.32	137,376
May	1.70	1.54	80,499
June	1.92	1.76	38,549
July	1.92	1.75	43,000
August	1.90	1.75	115,434
September	1.75	1.25	45,391
October	1.75	1.00	107,994
November	1.25	0.99	173,000
December	1.09	0.80	207,334
<b><u>2009</u></b>			
January	1.50	0.88	268,165
February	1.60	1.20	130,925
March (to March 16)	1.35	1.20	26,500

## DIRECTORS AND OFFICERS

The following table sets forth the name, age, municipality of residence, date first elected as a director of Ironhorse where applicable and office held for each of the directors and officers of Ironhorse together with their principal occupations during the last five years. The directors of Ironhorse shall hold office until the next annual meeting of shareholders or until their respective successors have been duly elected or appointed.

Name, Age and Jurisdiction of Residence	Office Held	Date First Elected or Appointed as Director of Ironhorse	Principal Occupation
<b>Larry J. Parks</b> <sup>(2)</sup> <b>Alberta, Canada</b> Age:53	President & Chief Executive Officer and a Director	June 26, 2003	Mr. Parks was appointed President & Chief Executive Officer and a director of Ironhorse in 2003. Mr. Parks is also the President & Chief Executive Officer of Grizzly Resources Ltd., a private oil and gas exploration and production company. Mr. Parks has more than 30 years of experience in the oil and gas industry.
<b>Gerry C. Quinn</b> <sup>(1)</sup> <b>Ontario, Canada</b> Age:60	Director	January 31, 2004	President of The Erin Mills Investment Corporation, a private venture capital company.
<b>James K. Wilson</b> <sup>(1)(2)</sup> <b>Alberta, Canada</b> Age: 56	Director, Vice President & Corporate Secretary	June 26, 2003	Mr. Wilson was appointed Corporate Secretary and a director in 2003 and served as Vice President, Finance & Chief Financial Officer of the Company from June 2003 to April 2005 and was re-appointed as the interim Vice President, Finance & Chief Financial Officer in December, 2007 for which he served until April 2008 when he returned to the position of Vice President & Corporate Secretary. Mr. Wilson is also Vice President Finance & Chief Financial Officer of Grizzly Resources Ltd. Mr. Wilson has 26 years of financial management experience in the oil and gas industry.
<b>Michael Royan</b> <sup>(1)</sup> <b>Alberta, Canada</b> Age:37	Director	February 11, 2009	President and Managing Director of Stonepoint Strategic Advisors Inc., which provides financial advisory services to companies primarily in the oil and gas and oilfield services industries since 2003. Mr. Royan has over 15 years of experience in the financial services industry in the areas of mergers, acquisitions, valuations, fairness opinions, corporate finance and corporate strategy.
<b>Rob Solinger</b> <b>Alberta, Canada</b> Age:52	Vice President, Finance & Chief Financial Officer	N/A	Vice President, Finance & Chief Financial Officer of Ironhorse since April 2008. Prior to joining Ironhorse, Mr. Solinger was Vice President, Finance and Chief Financial Officer of Defiant Resources Corporation from November 2005 until March 2008 and prior thereto Chief Financial Officer of Outlook Energy Corp., a private junior oil and gas company. Mr. Solinger has been in the oil and gas industry for more than 20 years.

<b>Name, Age and Jurisdiction of Residence</b>	<b>Office Held</b>	<b>Date First Elected or Appointed as Director of Ironhorse</b>	<b>Principal Occupation</b>
<b>Cam Weston</b> Alberta, Canada Age:54	Vice President, Land	N/A	Mr. Weston was appointed Vice-President, Land in 2008. He is also Vice President, Land of Grizzly Resources Ltd. Prior to joining Ironhorse, Mr. Weston was Vice-President, Land for Mancal Energy Inc. since 1999. Mr. Weston has been in the oil and gas industry for more than 30 years.
<b>William G. Manley</b> Alberta, Canada Age:54	Vice President, Engineering & Operations	N/A	Mr. Manley was appointed Vice President, Engineering & Operations in 2003. He is also Vice-President, Engineering & Operations of Grizzly Resources Ltd. Mr. Manley has been active in the oil and gas industry for the past 27 years.
<b>Al Williams</b> Alberta, Canada Age:56	Vice President, Exploration	N/A	Mr. Williams was appointed Vice President, Exploration in March 2008. He is also Vice President, Exploration of Grizzly Resources Ltd. Prior thereto Mr. Williams was Senior Geologist at Crew Energy Inc. and has held the position of Vice President, Exploration and Exploration Manager at several small to intermediate oil and gas companies since 1985. Mr. Williams has been in the oil and gas industry for the past 30 years.

Notes:

- (1) Member of Audit Committee.
- (2) Member of Reserves Committee.
- (3) The term of office of all directors expire on the date of the next annual meeting of holders of Common Shares.

As at March 16, 2009, the directors and officers of Ironhorse, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 5,178,858 Common Shares, representing approximately 24% of the issued and outstanding Common Shares.

#### **Cease Trade Order, Bankruptcies, Penalties or Sanctions**

No director or executive officer:

- (a) is as of the date hereof, or has been, within the 10 years before the date hereof, a director or chief executive officer or chief financial officer of any company, including Ironhorse, that while that person was acting in that capacity:
  - (i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days;
  - (ii) was the subject to an event that resulted, after the director or executive officer ceased to be a director or chief executive officer or chief financial officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days;
  - (iii) or within a year of that person ceasing to act in that capacity, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver manager or trustee appointed to hold its assets ; or

- (b) has, within the 10 years before the date of the annual information form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or shareholder.

In addition, no director or executive officer, or shareholder holding a sufficient number of securities of Ironhorse to affect materially the control of the Company, has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

### **Conflicts of Interest**

There are potential conflicts of interest to which the directors and officers of Ironhorse are subject to in connection with the operations of Ironhorse. In particular, certain of the directors and officers of Ironhorse are involved in managerial or director positions with other oil and gas companies, including Grizzly Resources Ltd. who provides technical services to the Company, whose operations may, from time to time, be in direct competition with Ironhorse or with entities which may, from time to time, provide financing to, or make equity investments in, Ironhorse's competitors. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Company are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract.

## **INDUSTRY CONDITIONS**

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

### **Pricing and Marketing Oil and Natural Gas**

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

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m<sup>3</sup>/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

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

## **Pipeline Capacity**

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

## **The North American Free Trade Agreement**

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

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

## **Provincial Royalties and Incentives**

### ***General***

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

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

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

## *Alberta*

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. Prior to the NRF, the amount of royalties that were payable was influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil was "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it was considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it was considered "new oil". The Alberta Government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 35%. The NRF eliminates this classification and establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches \$120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches \$16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling, which program became effective January 1, 2009. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on January 1, 2009 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

Oil sands projects are now subject to the NRF, and regulated, among others, by the *Oil Sands Royalty Regulation, 2009* and the *Oil Sands Allowed Costs (Ministerial) Regulation* and the *Bitumen Valuation Methodology (Ministerial) Regulation, 2009*, all approved by the Alberta Government on December 10, 2008. The rates applicable to oil sands are between 1% and 9% and are calculated depending on the price of oil. The royalty payable is 1% when oil is priced below or at \$55 per barrel and it increases for every dollar over and above that price, to a maximum of 9% when oil is priced at \$120 or higher. The after payout net royalty starts at 25% and increases for every dollar when oil is priced above \$55 up to 40% when oil is priced at \$120 or higher.

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

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy will be the one to decide which projects qualify

and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

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

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a \$200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas.

The three-point incentive program also includes an investment of \$30,000,000 by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and gas wells and to stimulate new activity within the services sector.

### ***British Columbia***

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m<sup>3</sup> produced, whichever comes first; and the royalties for third tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty than the royalty payable on non conservation gas.

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

Some of the financial incentives in the Strategy include:

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

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

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

### ***Saskatchewan***

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

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

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

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

associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.
- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

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

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

### **Land Tenure**

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

### **Environmental Regulation**

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

Environmental legislation in the Province of Alberta has been consolidated into the Environmental Protection and Enhancement Act (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the Oil and Gas Conservation Act (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines

outlined in the Climate Change and Emissions Management Amendment Act came into effect on July 1, 2007 ("CCEMAA"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the Specified Gas Emitters Regulation, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed \$40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

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

British Columbia's Environmental Assessment Act became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, the Provincial Government introduced on July 1, 2008, revenue-neutral carbon tax legislation that is applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO<sub>2</sub>e of \$10 per tonne for the first six months of 2009 and \$15 per tonne for the last six months of 2009, following \$5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government would receive otherwise. On April 3, 2008, the Government of British Columbia introduced the Greenhouse Gas Reduction (Cap and Trade) Act which will allow the Province to participate in the Western Climate Initiative cap and trade systems being developed. The system establishes a limit on emissions, and allows regulated emitters to buy/sell emission allowances or offset emits. The emitter is obliged to obtain emission allowances (compliance units) equal to the amount of greenhouse gases emitted within a certain period of time, and that are supposed to be surrendered to the Government as compliance proof.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("Kyoto Protocol"). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business as usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C 288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") also known as ecoACTION

which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

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

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

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

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO<sub>2</sub> equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO<sub>2</sub> equivalent per upstream oil and gas facilities; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO<sub>2</sub> equivalent per year per facility.

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

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

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

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

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

## Trends

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Recently, liquefied natural gas shipments to North America have also resulted in natural gas supply and natural gas pricing being based more on factors other than supply and demand in North America. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ("OPEC") ability to adjust supply to world demand and weather. Political events also trigger large fluctuations in price levels. The current global financial crisis has reduced liquidity in financial markets thereby restricting access to financing and has caused significant volatility to commodity prices. Petroleum prices are expected to remain volatile for the remainder of 2009 as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns. See "Risk Factors – Global Financial Crisis".

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. Material increases in the value of the Canadian dollar may negatively impact production revenues from Canadian producers. Such increases may also negatively impact the future value of such entities' reserves as determined by independent evaluators. In recent years, the Canadian dollar has increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. See "Risk Factors – Prices, Markets and Marketing".

A second trend within the Canadian oil and gas industry is the "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. To the extent that this trend continues, the Company will have to compete with these companies and others to attract qualified personnel.

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the global economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the Kyoto Protocol and other environmental initiatives will have on the sector and, in more recent times, by the tax changes relating to income trusts and other "specified investment flow-through" entities ("SIFTs") and by the NRF and new Alberta government royalty programs implemented along with the NRF. The impact of the NRF and these new royalty programs is still being determined and will vary company to company based on the percentage of production in Alberta, their commodity mix and depths of production, among other things. The amount and degree of these impacts have yet to be determined.

Pursuant to the existing provisions of the Tax Act, to the extent that a SIFT has any income for a taxation year after certain inclusions and deductions, the SIFT will be permitted to deduct all amounts of income which are paid or become

payable by it to unitholders in the year. Under the legislation which received Royal Assent on June 22, 2007, SIFTs will be liable for tax at a rate consistent with the taxes currently imposed on corporations commencing in January 2011, provided that the SIFT experiences only "normal growth" and no "undue expansion" before then, in which case the tax could be imposed prior to the January 2011 deadline. Although the tax changes will not affect the method in which the Company will be taxed, it may have an impact on the ability of a SIFT to purchase producing assets from oil and gas exploration and production companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting exploration and production companies' ability to be sold to a SIFT which has been a key "exit strategy" in recent years for oil and gas companies. This may be a benefit for the Company as it will compete with SIFTs for the acquisition of oil and gas properties from junior producers. However, it may also limit the Company's ability to sell producing properties or pursue an exit strategy.

## **RISK FACTORS**

**An investment in Ironhorse is speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. An investor should consider carefully the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision.**

### **Exploration, Development and Production Risks**

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Ironhorse depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. In excess of 90% of the Company's December 31, 2008 reserves are located at its principal property in Shackleton, Saskatchewan. Without the continual addition of new reserves, Ironhorse's existing reserves and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Ironhorse's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Ironhorse will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of Ironhorse may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Ironhorse.

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

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

## **Global Financial Crisis**

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

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

## **Prices, Markets and Marketing**

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

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Ironhorse's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of Ironhorse's reserves. Ironhorse might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Ironhorse's net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. In addition, bank borrowings available to Ironhorse will be in part determined by Ironhorse's borrowing base. A sustained material decline in prices from historical average prices could reduce Ironhorse's borrowing base, therefore reducing the bank credit available to Ironhorse which could require that a portion, or all, of Ironhorse's bank debt be repaid and a liquidation of assets.

## **Economic Dependence**

In 2008, Ironhorse produced over 90% of its production from its Shackleton property, located in southwestern Saskatchewan. Although the Company has expanded its core areas of operations, the Company relies on the continued performance of this area to contribute to its future operational success.

## **Operational Dependence**

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

All of Ironhorse's operations involve joint ventures with other industry partners. The Company's fields in Pembina, Alberta, Shackleton, Saskatchewan, and north east British Columbia are carried out through joint ventures with junior to large Canadian independent oil and gas companies and Ironhorse relies on the financial, operational and business success of these companies.

## **Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

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

## **Project Risks**

Ironhorse manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Ironhorse's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond Ironhorse's control, including:

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

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

## **Competition**

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

## **Regulatory**

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

## **Kyoto Protocol**

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

## **Environmental**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Ironhorse to incur costs to remedy such discharge. Although Ironhorse believes that it is in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Ironhorse's financial condition, results of operations or prospects. See "*Industry Conditions – Environmental Regulation*".

## **Variations in Foreign Exchange Rates and Interest Rates**

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar may negatively impact Ironhorse's production revenues. Further material increases in the value of the Canadian dollar would exacerbate this potential negative impact. This increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of Ironhorse's reserves as determined by independent evaluators.

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

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

## **Substantial Capital Requirements**

Ironhorse anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Ironhorse's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Ironhorse. The inability of Ironhorse to access sufficient capital for its operations could have a material adverse effect on Ironhorse's financial condition, results of operations and prospects.

## **Additional Funding Requirements**

Ironhorse's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Ironhorse may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Ironhorse to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Ironhorse's revenues from its reserves decrease significantly for a sustained period of time as a result of lower oil and natural gas prices or otherwise, Ironhorse's ability to expend the necessary capital to replace its reserves or to maintain its production will be impaired. If Ironhorse's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on favourable terms.

## **Issuance of Debt**

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

## **Hedging**

From time to time Ironhorse may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Ironhorse will not benefit from such increases. Similarly, from time to time Ironhorse may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, Ironhorse will not benefit from the fluctuating exchange rate.

## **Availability of Drilling Equipment and Access**

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Ironhorse and may delay exploration and development activities. To the extent Ironhorse is not the operator of its oil and gas properties, Ironhorse will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

## **Title to Assets**

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat Ironhorse's claim which could result in a reduction of the revenue received by Ironhorse.

## **Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Ironhorse's actual production, revenues, taxes and development

and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, GLJ has used forecast prices and costs in estimating the reserves and future net cash flows contained in the GLJ Report. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from Ironhorse's oil and gas reserves will vary from the estimates contained in the GLJ Report and such variations could be material. The GLJ Report is based in part on the assumed success of activities Ironhorse intends to undertake in future years. The reserves and estimated cash flows set out in the GLJ Report will be reduced to the extent that such activities do not achieve the level of success assumed in the GLJ Report.

### **Insurance**

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

### **Geo-Political Risks**

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

In addition, Ironhorse's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. As the oil and gas industry in Canada is a key supplier of energy to the United States, certain terrorist groups may target Canadian oil and gas properties, wells and facilities in an effort to negatively affect the United States economy. If any of Ironhorse's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Ironhorse. Ironhorse does not have insurance to protect against the risk from terrorism.

### **Dividends**

Any decision to pay dividends on the Common Shares will be made by the board of directors of Ironhorse on the basis of Ironhorse's earnings, financial requirements and other conditions existing at such future time. See "*Dividend Policy*".

### **Conflicts of Interest**

Certain directors of Ironhorse are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "*Directors and Officers – Conflicts of Interest*".

## **Management of Growth**

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

## **Expiration of Licenses and Leases**

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

## **Aboriginal Claims**

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. Ironhorse is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful this could have an adverse effect on Ironhorse and its operations.

On September 1, 2006, the Government of Alberta's First Nations Consultation Guidelines on Land Management and Resource Development were released. These guidelines support the previously issued First Nations Consultation Policy (May, 2005) and First Nations Framework for Consultation Guidelines. Under this policy certain procedural aspects of consultation with respect to specific projects will be delegated to the Company. These requirements may result in additional delays and costs which could have an adverse effect on the Company and its operations.

## **Seasonality**

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

## **Third Party Credit Risk**

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

## **Reliance on Key Personnel**

Ironhorse's success depends in large measure on certain key personnel, including but not limited to the personnel who provide services to the company pursuant to the Company's technical services with Grizzly Resources Ltd. The loss of the services of such key personnel could have a material adverse effect on Ironhorse. Ironhorse does not have any key person insurance in effect for management. The contributions of the existing management team to the immediate and near term operations of Ironhorse are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Ironhorse will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of Ironhorse.

## **Dilution**

Ironhorse may take future acquisitions or enter into financing or other transactions involving the issuance of securities of the Company which may be dilutive.

## **Delays in Business Operations**

In addition to the usual delays in payments by purchasers of oil and natural gas to Ironhorse or to the operators, and the delays by operators in remitting payment to the Company, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connections of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Company in a given period and expose the Company to additional third party credit risks.

## **Changes in Legislation**

The return on an investment in securities of Ironhorse is subject to changes in Canadian federal and provincial tax laws and government incentive programs and there can be no assurance that such laws or programs will not be changed in a manner that adversely affects the Company or the holding and disposing of the securities of the Company.

## **Income Taxes**

As the Company is engaged in the oil and natural gas business its operations are subject to certain unique provisions of the Tax Act and applicable provincial income tax legislation relating to characterization of costs incurred in their businesses which affects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. Ironhorse files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of costs or otherwise, such reassessment may have an impact on current and future taxes payable.

## **Accounting Write-Downs as a Result of GAAP**

Canadian generally accepted accounting principles ("**GAAP**") require that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the financial statements of Ironhorse. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of the Company's Common Shares.

Under GAAP, the net amount at which petroleum and natural gas properties are carried are subject to a cost-recovery test which is based in part upon estimated future net cash flow from oil and natural gas reserves. If net capitalized costs exceed the future discounted cash flows, Ironhorse will have to charge the amounts of the excess to earnings. A decline in the estimated future net cash flow from oil and natural gas reserves could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings.

GAAP requires that goodwill balances be assessed at least annually for impairment and that any permanent impairment be charged to net income. A permanent reduction in reserves, decline in commodity prices, and/or reduction in the trading price of the common shares of the Company may indicate a goodwill impairment. An impairment would result in a write-down of the goodwill value and a non-cash charge against net income. The calculation of impairment value is subject to management estimates and assumptions.

## **HUMAN RESOURCES**

At December 31, 2008, the Company had one full time employee (December 31, 2007 — one). The Company's management provides sufficient time as considered necessary to carry out the duties and responsibilities of the Company and to provide the Company with the technical and operational expertise required by an oil and gas company. Management intends to add additional professional and administrative staff as the need arises.

Ironhorse has also entered into a management agreement with Grizzly Resources Ltd. pursuant to which Grizzly Resources Ltd. personnel provide services in respect of the management, development, exploitation and operation of the assets of Ironhorse. Pursuant to this agreement, Ironhorse paid \$2.35 per producing boe and 4% of capital expenditures made by Ironhorse. These rates are adjusted annually for changes in the Consumer Price Index.

### **LEGAL PROCEEDINGS AND REGULATORY ACTIONS**

To the knowledge of the Company, there are no legal proceedings material to the Company to which the Company is or was a party to, or of which any of its properties are or were the subject of, during the financial year ended December 31, 2008, nor are there any such proceedings known to the Company to be contemplated.

During the year ended December 31, 2008, there were no (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority.

### **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

There were no material interests, direct or indirect, of directors or executive officers of Ironhorse, any holder of Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect Ironhorse.

### **AUDITORS, TRANSFER AGENT AND REGISTRAR**

The auditors of the Company are Kenway Mack Slusarchuk Stewart, LLP, Chartered Accountants, 333 - 11 Avenue SW Suite 220 Calgary, Alberta T2R 1L9.

The Company's transfer agent and registrar is Valiant Trust Company, 310, 606 - 4th Street SW Calgary, Alberta T2P 1T1.

### **MATERIAL CONTRACTS**

Except for contracts entered into in the ordinary course of business, Ironhorse has not entered into any material contracts within the last financial year, or before the last financial year which are still in effect.

### **INTERESTS OF EXPERTS**

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 by the Company during, or related to, the Company's most recently completed financial year other than GLJ, the Company's independent engineering evaluators and Kenway Mack Slusarchuk Stewart, LLP, as auditors. None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any of the Company's securities or other property or of the Company's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. Kenway Mack Slusarchuk Stewart, LLP, the Company's auditors, are independent in accordance with the auditor's rules of professional conduct in Alberta.

### **ADDITIONAL INFORMATION**

Additional information including information relating to remuneration and indebtedness of directors and officers of Ironhorse, principal holders of Common Shares and securities authorized for issuance under the Company's equity compensation plans, will be contained in the information circular relating to the Company's annual meeting of Shareholders to be held on Thursday May 14, 2009 at 10:00 am. Additional financial information is provided in the Company's comparative financial statements and management discussion and analysis of financial results for the year

ended December 31, 2008. Alternatively, additional information relating to the Company is available on SEDAR at [www.sedar.com](http://www.sedar.com).

For copies of the Company's information circular, the Company's comparative financial statements, including any interim comparative financial statements and additional copies of the Annual Information Form please contact:

Attention: Vice President, Finance & CFO  
Ironhorse Oil & Gas Inc.  
1000, 324 - 8th Avenue S.W.  
Calgary, Alberta T2P 2Z2  
Tel: (403) 355-3620  
Fax: (403) 264-8740

**SCHEDULE "A"**  
**FORM 51-101F3**  
**REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE**

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

An independent qualified reserves evaluator has evaluated Ironhorse's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of Ironhorse has

- (a) reviewed Ironhorse's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors of Ironhorse has reviewed Ironhorse's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

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

DATED as of this 11<sup>th</sup> day of February, 2009.

(signed) "*William G. Manley*"  
William G. Manley  
Vice President, Engineering & Operations

(signed) "*James K. Wilson*"  
James K. Wilson  
Vice President, Corporate Secretary, a  
Director and Member of the Reserves  
Committee

(signed) "*Larry J. Parks*"  
Larry J. Parks  
President & Chief Executive Officer, a  
Director and Member of the Reserves  
Committee

**SCHEDULE "B"**  
**FORM 51-101F2**  
**REPORT ON RESERVES DATA**  
**BY INDEPENDENT QUALIFIED RESERVES EVALUATORS**

To the board of directors of Ironhorse Oil & Gas Inc. (the "Company"):

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

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

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

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	January 15, 2009	Canada	-	\$48,684		<b>\$48,684</b>

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

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

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

EXECUTED as to our report referred to above.

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 11, 2009

(signed) "John E. Keith"  
 John E. Keith, P.Eng.  
 Manager, Engineering