IRONHORSE OIL & GAS INC.

Statement of Reserves Data and Other Oil and Gas Information

Effective December 31, 2010

Dated April 13, 2011

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ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

bbl	barrel	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Mcf/d	thousand cubic feet per day
bbl/d	barrels per day	MMBtu	million British Thermal Units
NGLs	natural gas liquids	Bcf	billion cubic feet
boe/d	barrels of oil equivalent per day	GJ	gigajoule

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. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
boe	barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
Mcfe	1,000 cubic feet of gas equivalent
MBOE	1,000 barrels of oil equivalent
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"Reserves" are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically recoverable from discovered resources, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) 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.

"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.

"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.

"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.

"Undeveloped" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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, possible) 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 sub-divide 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 recorded from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"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 + probable reserves. The following terms, used in the preparation of the Evaluator's Report (as defined herein) and this document have the following meanings:

"Associated gas" means the gas cap overlying a crude oil accumulation in a reservoir.

"**Company"** or **"Ironhorse"** means Ironhorse Oil & Gas Inc.

"Crude oil" or **"Oil"** means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"Development well" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"Exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");
(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;
(c) dry hole contributions and bottom hole contributions;
(d) costs of drilling and equipping exploratory wells; and
(e) costs of drilling exploratory type stratigraphic test wells.

"Exploratory well" means a well that is not a development well, a service well or a stratigraphic test well.

"Field" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as

a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

"Future prices and costs" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;
(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company issuer is 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).

"Future income tax expenses" means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"Future net revenue" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

"Gross" means:

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

"Natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

"Natural gas liquids" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"Net" means:

(a) in relation to the Company's interest in production or reserves its working interest (operating or non operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its 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 owned by the Company.

"Non-associated gas" means an accumulation of natural gas in a reservoir where there is no crude oil.

"Operating costs" or "production costs" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"Production" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"Property" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"Property acquisition costs" means costs incurred to acquire a property (directly by purchase or lease or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;
(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;
(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"Proved property" means a property or part of a property to which reserves have been specifically attributed.

"Reservoir" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"Solution gas" means natural gas dissolved in crude oil.

"Stratigraphic test well" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) exploratory type" if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"Support equipment and facilities" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"Unproved property" means a property or part of a property to which no reserves have been specifically attributed.

"Well abandonment costs" means costs of abandoning a well and surface lease reclamation. They do not include costs of abandoning the gathering system, suspended wells, batteries, plants, or processing facilities.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

In accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, GLJ Petroleum Consultants ("GLJ") and Sproule Associates Limited ("Sproule") or collectively the ("Evaluator") prepared a report (the "Report") with respect to Ironhorse Oil & Gas Inc.'s oil, NGL and natural gas reserves with an effective date of December 31, 2010. Estimates of reserves and projections of production were generally prepared using general well information and production data available in the public domain to approximately November 30, 2010. In certain instance the Company provided production and well information up to December 31, 2010. The preparation date of this report is February 3, 2011. The tables below are a summary of the oil, NGL and natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the Report based on forecast price and cost assumptions. The tables summarize the data contained in the Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. GLJ evaluated all of Ironhorse's properties other than the Pembina, Alberta property that accounts for approximately 31% of the total proved plus probable reserves, which was evaluated by Sproule. **The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Evaluator. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by Evaluator represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Company's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.**

The Report is based on certain factual data supplied by the Company and Evaluator's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to Evaluator and accepted without any further investigation. The Evaluator accepted this data as presented and neither title searches nor field inspections were conducted.

All properties are in Western Canada.

All monetary values are expressed in Canadian unless stated otherwise.

FORECAST PRICES AND COSTS – Effective December 31, 2010

2.1.1 SUMMARY OF OIL AND GAS RESERVES

Summary of Oil & Gas Reserves Summary										
	Light and Medium Oil		Heavy Oil		Natural Gas [1]		Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED										
Producing	80	46	72	70	7,849	6,471	4	2	1,464	1,196
Developed Non-Producing	0	0			1,686	1,539	9	8	291	264
Undeveloped	646	395	28	28	1,193	791	88	60	961	615
Total Proved	**725**	**440**	**100**	**98**	**10,728**	**8,801**	**101**	**70**	**2,715**	**2,075**
Total Probable	209	123	130	125	4,042	3,313	25	17	1,037	818
Total Proved Plus Probable	**934**	**563**	**230**	**223**	**14,770**	**12,114**	**126**	**87**	**3,752**	**2,892**

2.1.2 SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (%/Year)				Unit Value Before Income Tax Discounted at 10%/year		After Income Taxes Discounted at (%/Year)			
Reserves Category	5% (M$)	10% (M$)	15% (M$)	20% (M$)	$/boe	$/Mcfe	5% (M$)	10% (M$)	15% (M$)	20% (M$)
PROVED										
Producing	19,790	17,007	14,929	13,336	14.22	2.37	19,790	17,007	14,929	13,336
Developed Non-Producing	2,228	1,384	849	500	5.24	0.87	2,228	1,384	849	500
Undeveloped	28,543	23,659	19,918	16,983	38.50	6.42	23,182	19,388	16,445	14,109
Total Proved	50,562	42,050	35,696	30,819	20.27	3.38	45,201	37,779	32,223	27,945
Total Probable	19,307	13,923	10,553	8,264	17.03	2.84	14,435	10,371	7,825	6,128
Total Proved Plus Probable	69,869	55,973	46,230	39,083	19.35	3.23	59,636	48,151	40,048	34,073

2.1.3 TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Capital Development Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
PROVED								
Producing	57,979	10,837	22,326	8	1,191	23,616	0	23,616
Developed Non-Producing	12,171	1,178	5,198	2,117	76	3,602	0	3,602
Undeveloped	75,849	27,371	6,623	6,689	54	35,111	6,900	28,210
Total Proved	145,999	39,386	34,147	8,814	1,322	62,330	6,900	55,429
Total Probable	64,651	14,532	20,082	1,271	287	28,478	7,109	21,369
Total Proved Plus Probable	210,650	53,918	54,229	10,085	1,609	90,808	14,010	76,798

2.1.3(a) FUTURE NET REVENUE BY PRODUCTION GROUP

		Future Net Revenue Before Income Taxes (3) (Discounted at 10% per year)		
		(M$)	$/boe	$/Mcfe
Proved Producing				
	Light & Medium Crude Oil (1)	2,225	49.34	8.22
	Heavy Oil (1)	2,009	28.63	4.77
	Natural Gas (2)	12,774	11.82	1.97
Total Proved Producing		**17,007**	**14.22**	**2.37**
Total Proved				
	Light & Medium Crude Oil (1)	25,853	40.92	6.82
	Heavy Oil (1)	2,039	20.82	3.47
	Natural Gas (2)	14,158	10.53	1.75
Total Proved		**42,050**	**20.27**	**3.38**
Proved Plus Probable				
	Light & Medium Crude Oil (1)	33,456	42.38	7.06
	Heavy Oil (1)	3,711	16.65	2.77
	Natural Gas (2)	18,806	10.00	1.67
Total Proved Plus Probable		**55,973**	**19.35**	**3.23**

1 Including solution gas and other by-products
2 Including by-products but excluding solution gas
3 Unit values are based on Company Net Reserves

3.1 PRICING ASSUMPTIONS OF FORECAST PRICES USED IN ESTIMATES

Evaluator employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2010 in estimating the Company's reserves data using forecast prices and costs.

	OIL[1]				NGLs	NATURAL GAS		
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Heavy Oil Hardisty 12° API ($Cdn/bbl)	Medium Oil Cromer 29° API ($Cdn/bbl)	Edmonton Propane ($Cdn/bbl)	AECO Gas Price ($Cdn/Mmbtu)	INFLATION RATES[2] %/Year	EXCHANGE RATE[3] (US/$Cdn)
2011	88.00	86.22	68.79	82.78	54.32	4.16	2.0	0.98
2012	89.00	89.29	68.33	83.04	56.25	4.74	2.0	0.98
2013	90.00	90.92	67.03	83.64	57.28	5.31	2.0	0.98
2014	92.00	92.96	67.84	84.59	58.56	5.77	2.0	0.98
2015	95.17	96.19	70.23	87.54	60.60	6.22	2.0	0.98
2016	97.55	98.62	72.03	89.75	62.13	6.53	2.0	0.98
2017	100.26	101.39	74.08	92.26	63.87	6.76	2.0	0.98
2018	102.74	103.92	75.95	94.57	65.47	6.90	2.0	0.98
2019	105.45	106.68	78.00	97.08	67.21	7.06	2.0	0.98
2020	107.56	108.84	79.59	99.04	68.57	7.21	2.0	0.98
2021+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.98

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

4.1 RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE

	Total Oil (Mbbl)			Light and Medium Oil (Mbbl)		
FACTORS	Proved	Probable	Proved +Probable	Proved	Probable	Proved +Probable
December 31, 2009	715	206	921	715	206	921
Extensions	125	120	246	97	21	118
Technical Revisions	(47)	(13)	(60)	(47)	(14)	(60)
Discoveries	116	33	150	35	3	38
Acquisitions	0	0	0	0	0	0
Dispositions	(20)	(7)	(28)	(20)	(7)	(28)
Economic Factors	0	0	0	0	0	0
Production	(64.3)	0.0	(64.3)	(54.8)	0.0	(54.8)
December 31, 2010	825	339	1,164	725	209	934
	Heavy Oil (Mbbl)			**NGL'S (Mbbl)**		
FACTORS	Proved	Probable	Proved +Probable	Proved	Probable	Proved +Probable
December 31, 2009	0	0	0	174	15	190
Extensions	28	99	127	0	0	0
Technical Revisions	0	1	0	(82)	5	(78)
Discoveries	82	30	112	10	5	15
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0
Production	(9.5)	0.0	(9.5)	(0.5)	0.0	(0.5)
December 31, 2010	100	130	230	101	25	126
	Natural Gas (1) (MMcf)			**BOE (Mboe)**		
FACTORS	Proved	Probable	Proved +Probable	Proved	Probable	Proved +Probable
December 31, 2009	12,016	5,218	17,234	2,892	1,091	3,983
Extensions	7	1	8	127	120	247
Technical Revisions	74	(843)	(768)	(116)	(150)	(266)
Discoveries	846	454	1,300	267	114	381
Acquisitions	0	0	0	0	0	0
Dispositions	(42)	(14)	(56)	(28)	(9)	(37)
Economic Factors	(543)	(775)	(1,318)	(91)	(129)	(220)
Production	(1,630.2)	0.0	(1,630.2)	(336.0)	0.0	(336.0)
December 31, 2010	10,728	4,042	14,770	2,715	1,037	3,752

(1) Includes solution gas.

5.1 UNDEVELOPED RESERVES ATTRIBUTED IN CURRENT YEAR

Undeveloped reserves have been assigned to the Pembina Nisku oil pool and at Leon Lake where one proved and two probable locations have been given Upper Shaunavon reserve assignments.

	L&M Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mbbl)	
Proved Undeveloped Reserves										
	1st Attributed	Total at Year end	1st Attributed	Total at Year end	1st Attributed	Total at year end	1st Attributed	Total at Year end	1st Attributed	Total at Year end
2007	-	-	-	-	5,098	5,729	-	-	850	955
2008	-	-	-	-	3,825	4,571	-	-	638	762
2009	691	691	-	-	1,372	1,372	172	172	1,092	1,092
2010	-	646	28	28	-	1,193	-	88	28	961
Probable Undeveloped Reserves										
	1st Attributed	Total at Year end	1st Attributed	Total at Year end	1st Attributed	Total at Year end	1st Attributed	Total at Year end	1st Attributed	Total at Year end
2007	-	-	-	-	1,515	1,776	-	-	253	296
2008	-	-	-	-	6,807	7,397	-	-	1,135	1,233
2009	198	198	-	-	117	117	15	15	233	233
2010	-	184	99	99	-	209	-	19	99	337

* Refers to reserves first attributed in this fiscal year ending on the effective date.

5.2 SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those inherent of an oil and gas producing company. Some of those risks are noted below.

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 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.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. 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 government regulations could result in longer than anticipated regulatory hearings which could impact the on stream date and production rates of the Nisku oil production in the Pembina area. Potential changes to Alberta's Crown royalty regime may help economic conditions.

5.3 FUTURE DEVELOPMENT COSTS

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only).

	Total Proved (M$)	**Total Proved Plus Probable (M$)**
2011	1,796	1,796
2012	4,330	5,455
2013	68	0
2014	735	804
2015	704	0
2016	0	825
2017	1,182	0
2018	0	1,205
Remainder	0	0
Total for All Years	8,814	10,085
10% Discounted	7,140	8,095

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

6.1 OIL AND GAS PROPERTIES AND WELLS

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, 2010 in the Evaluator Report. Based on the estimated net present value of future net revenue, before income taxes and discounted at 10% per annum, GLJ and Sproule 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, 2010, except where indicated otherwise.

Dawson, Alberta

The Company's Dawson property is located in Township 79, Range 17, W5. There are two (1.1 net) producing Slave Point oil wells. The wells were placed on production in 2010 and are currently producing 220 bbls of oil per day.

Leon Lake, Saskatchewan

The Company's Leon Lake property is located in Townships 7 & 8, Range 18 W3. There are currently two (1.8 net) producing Upper Shaunavon oil wells. The wells were placed on production in 2010 and are currently producing 35 (25 net) bbls of oil per day.

Pembina, Alberta

The Company's Pembina property is located in Township 50, Range 6, W5, approximately 30 miles west of Edmonton Alberta. There are currently two (0.4 net) shut-in Nisku oil wells in the Nisku L2L pool that are waiting on regulatory approvals and construction of infrastructure before the wells can be placed on production. In order to place the wells on production processing and transportation infrastructure to handle the associated sour gas that will be produced with the oil must be approved and constructed by the Company and its partners. In addition, to produce the wells to their full capabilities a pressure maintenance scheme will need to be implemented with the drilling of two water injector wells and a water source well.

Shackleton, Saskatchewan

The Company's Shackleton shallow gas property is located in Township 21 and 22, Ranges 18 to 20,W3 near Abbey, Saskatchewan. The property is producing natural gas from the Milk River formation. The Company has a 50% working interest in 100 (50 net) producing gas wells and associated infrastructure including a gas plant and gathering system.

The following table sets forth the number of wells in which the Company held a working interest as at December 31, 2010:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Dawson	2	1.1	-	-	-	-	-	-
Jedney	-	-	-	-	-	-	1	0.8
Leon Lake	2	1.8	-	-	-	-	-	-
Lochend	13	1.3	3	0.3	-	-	-	-
Pembina	-	-	3	0.5	-	-	-	-
Shackleton	-	-	-	-	100	50	-	-
TOTAL	17	4.2	6	0.8	100	50	1	0.8

6.2 PROPERTIES WITH NO ATTRIBUTED RESERVES

	Gross Acres	*Net Acres*	*Net Acres to Expire in 2011*
Alberta	*6,720*	*2,175*	*177*
Saskatchewan	*7,360*	*6,760*	*-*
British Columbia	*7,948*	*5,175*	*-*
Total	*22,028*	*14,110*	*177*

The Company has no work commitments with respect to these properties.

6.3 ADDITIONAL INFORMATION ON ABANDONMENT & 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 127 wells and certain facilities that the Company has a working interest ownership. The total abandonment and site restoration costs are estimated by the Company at $3.4 million. The Evaluator 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-reserve wells, production facilities and pipelines. In the determination of future net revenue associated with the total proved plus probable reserves, Evaluator estimated well abandonment costs of $1.3 million for proved reserves ($295 thousand when discounted at 10%), and $1.6 million for proved plus probable reserves ($194 thousand when discounted at 10%), of which $9 thousand, nil and $20 thousand is to be incurred in 2011, 2012 and 2013, respectively.

6.4 TAX HORIZON

Based on the after tax economic forecasts prepared by GLJ, income taxes are payable by the Company beginning in 2013 in the total proved plus probable reserves class. Based on our internal forecast, we do not expect the Company will be taxable during the next two years. Taxability beyond December 31, 2013 will depend on commodity prices and the level of capital investment made annually by the Company.

6.5 COSTS INCURRED

The following table summarizes the capital expenditures, net of proceeds on dispositions and drilling incentive credits made by Ironhorse on oil and natural gas properties for the period ended December 31, 2010:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
	(M$)	(M$)	(M$)	(M$)
Canada	(518)	3,045	8,279	2,756

6.6 EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table sets forth the number of exploratory and development wells that Ironhorse drilled during the year ended December 31, 2010:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Canada				
Oil Wells	3	2.3	1	0.6
Gas Wells	1	0.8	-	-
Service Wells	-	-	-	-
Dry Holes	-	-	-	-
Total Completed Wells	4	3.1	1	0.6

During the year ended December 31, 2010, Ironhorse drilled and completed two (1.1net) oil wells at Dawson, Alberta; two (1.8 net) oil wells at Leon Lake, Saskatchewan and one (0.8 net) gas well at Jedney, British Columbia. All of the oil wells were placed on production in 2010, the Jedney gas well will be placed on production when gas prices increase.

6.7 PRODUCTION ESTIMATES

The following table discloses for each product type the total volume of production estimated by the Evaluator for 2011 in the estimates of future net revenue from the forecast case of proved plus probable reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue".

	L&M Oil bbl/d		Heavy Oil bbl/d		Natural Gas Mcf/d		NGLs bbl/d		Oil Equivalent bbl/d	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved										
Shackleton	0	0	0	0	3,392	2,677	0	0	565	446
Other Properties	134	71	34	33	35	26	1	1	174	109
Total Proved	134	71	34	33	3,426	2,704	1	1	740	555
Probable										
Shackleton	0	0	0	0	56	39	0	0	9	7
Other Properties	13	6	4	3	1	1	0	0	17	9
TotalProbable	13	6	4	3	57	40	0	0	26	16
Proved Plus Probable										
Shackleton	0	0	0	0	3,448	2,717	0	0	575	453
Other Properties	147	77	37	36	36	27	1	1	191	118
Total Proved Plus Probable	147	77	37	36	3,484	2,744	1	1	766	571

Shackleton is currently the largest producing asset of the Company. In 2010 average production for the property was 6,300 mcf per day.

6.8 PRODUCTION HISTORY

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by Ironhorse for each quarter of its most recently completed financial period:

	2010			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Average Production				
NGL & Oil (bbl/d)	105	179	4,298	3,947
Natural Gas (Mcf/d)	5,044	4,633	203	223
Combined (BOE/d)	946	951	919	881
Selling Prices				
NGL & Oil ($/bbl)	77.61	71.08	72.24	76.24
Natural Gas ($/Mcf)	4.64	3.61	3.31	3.37
Combined (BOE/d)	33.34	30.99	31.41	34.41
Royalties				
NGL & Oil ($/bbl)	9.92	8.48	9.70	20.72
Natural Gas ($/Mcf)	1.22	0.85	0.75	0.72
Combined (BOE/d)	7.63	3.35	5.67	8.44
Production Costs				
NGL & Oil ($/bbl)	27.80	9.82	16.44	18.32
Natural Gas ($/Mcf)	0.58	0.38	0.78	1.03
Combined (BOE/d)	4.10	3.35	7.08	8.38
Netbacks				
NGL & Oil ($/bbl)	39.89	52.78	46.10	37.20
Natural Gas ($/Mcf)	2.84	2.38	1.78	1.62
Combined (BOE/d)	21.61	21.91	18.66	17.59

Production Volume by Field

The following table discloses for each important field and in total, Ironhorse Oil & Gas Inc. production volume for the period ended December 31, 2010 for each product type:

	NGL & Oil	Natural Gas	Total
	bbl/d	Mcf/d	boe/d
Shackleton	-	4,416	736
Dawson	144	4	145
Leon Lake	25	-	25
Other	8	45	16
Total	177	4,465	922