YEAR ENDED JANUARY 31, 2012
MANAGEMENT DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the consolidated financial position and results of operations of the Company, which includes its subsidiaries, was prepared as of May 30, 2012, and is for the years ended January 31, 2012 and 2011. For a full understanding of the consolidated financial position and results of operations of the Company, the MD&A should be read in conjunction with the documents filed on SEDAR, including historical financial statements and press releases. These documents are available at www.sedar.com. The selected financial information contained herein has been prepared in accordance with International Financial Reporting Standards, and are expressed in Canadian dollars, unless otherwise noted.

The Company's Board of Directors and Audit Committee have reviewed and approved the consolidated financial statements and MD&A.

Readers are cautioned of the advisories of forward-looking statements, estimates, non-IFRS measures and numerical references which can be found at the end of this MD&A. This MD&A is dated and was prepared using currently available information as of May 30, 2012.

Description of the Company

Thunderbird Energy Corp. (the "Company") is focused on the exploration, exploitation, acquisition and production of natural gas and crude oil, primarily in the United States. The Company owns and operates a producing natural gas field in Carbon County, Utah, known as the Gordon Creek field, and holds a 50% interest in a producing light oil project located in Rush County, Kansas. The Company also holds a 100% interest in a non-producing oil project in Weston County, Wyoming.

Changes in Accounting Policies

On February 1, 2011, the Company adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes, using the transition date of February 1, 2010. The consolidated financial statements for the year ended January 31, 2012, including required comparative information, have been prepared in accordance with IFRS 1 – *First-Time Adoption of International Financial Reporting Standards*, as issued by the International Accounting Standards Board ("IASB"). Previously, the Company prepared its Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). Unless otherwise noted, fiscal 2011 comparative information has been prepared in accordance with IFRS. The adoption of IFRS has not had an impact on the Company's operation, strategic decisions and funds flow from operations.

SELECTED ANNUAL INFORMATION

The following table set forth consolidated financial data prepared in accordance with IFRS for our last three fiscal years:

	January 31, 2012	January 31, 2011	January 31, 2010[(1)]
Total revenues	937,048	1,087,085	1,184,906
Net loss	(5,789,383)	(2,364,248)	(2,029,517)
Basic and diluted loss per share	(0.08)	(0.03)	(0.03)
Total assets	24,230,108	9,074,672	10,779,821
Total long-term financial liabilities	23,776,856	6,272,709	212,394

(1) Information prepared under Canadian GAAP in effect prior to the conversion to IFRS

The Company has not declared any cash dividends since inception.

HIGHLIGHTS AND OUTLOOK

On August 29, 2011 the Company entered into a US$25 million commodity stream production payment agreement with Sandstorm Metals & Energy Ltd. ("Sandstorm") whereby Sandstorm has the right to purchase 35% of the Company's Gordon Creek natural gas production at a price of $1.00 per Mcf plus 20% of the amount by which the Gordon Creek field gate price exceeds $4.00. Pursuant to the agreement, the Company is obligated to drill 50 additional wells and workover 5 standing wells on the Gordon Creek Property, while Sandstorm advanced $15 million to the Company and will advance a further US$10 million in fiscal 2013. In order to secure the further advance of US$10 million the Company must drill 15 wells and complete 5 workovers by December 31, 2012. The remaining 35 wells are to be drilled by December 31, 2013.

Subsequent to year-end, the Company and Sandstorm amended the commodity stream production payment agreement whereby all minimum cash flow guarantees and drilling commitments at Gordon Creek will be deferred by one year. As consideration for this deferral, in March 2013, Thunderbird will issue to Sandstorm $2.55 million of Thunderbird shares determined at a deemed price equivalent to 50 day volume weighted average trading price prior to issuance. Under the amended agreement, the Company has provided Sandstorm with minimum annual before tax cash flows guarantees earned through the sale of their 35% share of natural gas produced in Gordon Creek. The guarantee is the lesser of $2.3 million or 790mmcf by December 31, 2013, $5.1 million or 1740mmcf in calendar 2014, $4.6 million or 1560mmcf in calendar 2015, $4.2 million or 1410mmcf in calendar 2016, $3.8 million or 1260mmcf in calendar 2017, $3.3 million or 1140mmcf in calendar 2018 and $1.7 million or 590mmcf in calendar 2019.

As the ability of the Company to obtain the financing necessary to meet its full future exploration commitments under the agreement is uncertain, the Company has accounted for the $US15 million advance from Sandstorm as a financing deposit liability. In the event the Company should default on its future commitments, the default fee due to Sandstorm is amounts advanced or recovered from Sandstorm less production provided to Sandstorm and is due within 60 days of being in default.

Until December 31, 2013, the Company has the option to repurchase 50% of the commodity stream by making a $US16.25 million payment to Sandstorm, upon receipt of which, the percentage of natural gas Sandstorm will be entitled to purchase will decrease to 17.5%. If the Company drills additional wells on the Gordon Creek Property over and above the minimum 50 net wells, the Sandstorm has the option to have production from the additional net wells form a part of the commodity stream by providing additional production payment advances to the Company at an agreed amount per well.

Operations including surveying, permitting and a variety of pre-drilling activities commenced in the third quarter. By the end of the year, two wells had been drilled to depth, logged and cased for production, and a third well was drilling. The Company had also drilled and set surface casing for an addition five holes that were drilled subsequent to year end.

During the third quarter, the Company also commenced operations at the previously announced Gordon Creek Carbon Sequestration Phase III: Deep Saline Sequestration Deployment. This project will be funded approximately 80% by the US. Department of Energy (“DOE”) and 20% by the other participants, including Thunderbird, The University of Utah through the Utah Science Technology And Research initiative (“USTAR”) and the New Mexico Tech – Petroleum Recovery Research Center. Initial operations included a substantial workover of the Company’s GCU #1 well in order to significantly enhance the Company’s ability to inject both water and CO_2 into this well. During the fourth quarter, the US Department of Energy announced that due to internal policy changes, unrelated to the specific SWP CO_2 project, they were terminating a number of Deep Saline injection projects, including the Gordon Creek project. The Company anticipates that it will be reimbursed for roughly 80% of the costs incurred on the project up to January 2012.

Average natural gas prices realized by the Company during the first three fiscal quarters was comparable to the prior year, however prices declined sharply during the fourth quarter. As a result, prices realized by the Company during the year averaged US$3.29 compared to an average price of US$3.50 during the prior year. During the year, the Company entered into a fixed price forward sale of 200 Mcf/day for the period April 1, 2011 to October 31, 2011 at a price of $3.98 per Mcf.

US domestic production of natural gas remained strong throughout the year, however increased demand due to the economic recovery and extended periods of high temperatures throughout much of the US during the summer kept prices stable. However, during the late fall and early winter, temperatures in the US remained much above seasonal norms, which reduced the heating demand for gas and led to lower prices. Prices have rebounded somewhat in recent weeks due to utility companies' increased use of gas instead of coal for power generation and due to certain larger producers shutting in production. Natural gas drilling has also been reduced by up to 30% over the past twelve months leading to reduced growth in supplies. Natural gas pricing for the balance of the year will depend in large part on whether or not these trends continue and on the levels of weather dependent heating and cooling demand.

RESULTS OF OPERATIONS

	Three Months Ended			Year Ended	
	January 31, 2012	October 31, 2011	January 31, 2011	January 31, 2012	January 31, 2011
Operating Income/(Loss)[1]	**(95,751)**	**96,575**	**(30,618)**	**112,344**	**221,124**
General and administrative	(493,710)	(296,589)	(288,411)	(1,220,046)	(971,741)
Finance Costs	(186,213)	(787,596)	(204,686)	(767,446)	(719,861)
Funds Flow From Operations [1]	**(775,674)**	**(987,610)**	**(523,715)**	**(1,875,148)**	**(1,470,478)**
Non-cash operating items:					
Finance Costs	(649,897)	(1,523,524)	(341,537)	(3,145,516)	(813,868)
Depletion and depreciation	(37,488)	(69,530)	(48,765)	(202,400)	(221,893)
Share based compensation	(466,584)	(23,183)	(26,611)	(549,469)	(218,093)
Foreign exchange gain	409	(52,823)	5,400	(16,850)	29,345
Net loss for the period	**(1,929,234)**	**(2,656,670)**	**(935,228)**	**(5,789,383)**	**(2,694,987)**

[1] "Operating income" and "funds flow from operations" are non-IFRS terms and may not be comparable with the calculation of similar measures for other entities. Operating income is equal to petroleum and natural gas sales minus royalties, operating costs, while funds flow from operations represents cash flow from operations before net changes in operating working capital accounts. Refer to the advisory on non-IFRS measures at the end of this MD&A.

Operating Income Items

Sales Volumes

During the year ended January 31, 2012 the Company's gas sales volume averaged 574 mcf/d as compared to 610 mcf/d during the prior year, a decline of roughly 5.9%. During the three months ended January 31, 2012 the Company's gas sales volume averaged 595 mcf/d as compared to average daily gas sales volumes of 507 mcf/d during the comparable quarter of the prior year. Variability of production was due in part to workover operations conducted on the Company's GCU#1 well that, among other things, repaired the gas production string and returned the well to historical production levels.

The Company's Rush County, Kansas oil sales volumes for fiscal 2012 averaged 3 bbls/d, which was comparable to the prior year.

Production Summary

The following table summarizes the production for the fourth quarter and year of fiscal 2012 and fiscal 2011:

	Three months ended January 31,		Year ended January 31,	
	2012	2011	2012	2011
Production:				
Natural gas (mcf)	57,734	46,646	209,600	222,686
Oil (bbls)	279	286	1,061	1,097
Total (BOE) (6:1)	9,401	8,067	35,994	38,211
Production split:				
Natural gas (%)	97%	96%	97%	97%
Oil (%)	3%	4%	3%	3%

Average Realized Price

The following table summarizes the average realized price for the fourth quarter and year of fiscal 2012 and fiscal 2011:

		Three months ended January 31,		Year ended January 31,	
		2012	2011	2012	2011
Exchange Rate	*US$/Cdn$*	*.9796*	*0.9947*	*1.0094*	*0.9743*
Natural gas (mcf)	*US$/Mcf*	*$ 2.70*	*$ 3.33*	*$ 3.29*	*$ 3.50*
Oil (bbls)	*US$/bbls*	*$ 90.92*	*$ 84.08*	*$ 87.91*	*$ 74.45*

Revenues, Royalties & Operating Costs

	Three Months Ended			Year Ended	
	January 31, 2012	October 31, 2011	January 31, 2011	January 31, 2012	January 31, 2011
Revenues	$ 218,620	$ 250,447	$ 230,486	$ 937,048	$ 1,087,085
Royalties	25,576	39,969	36,610	155,086	181,974
Direct operating and transportation	288,795	113,903	224,494	669,618	683,987
Operating Income[1]	$ (95,751)	$ 96,575	$ (30,618)	$ 112,344	$ 221,124

[1] Refer to the advisories on non-IFRS measures at the end of this MD&A.

Revenues

Fourth quarter revenues decreased 13% over the third quarter of 2012 and 5% compared to the fourth quarter of fiscal 2011. Revenues for the fiscal year decreased 14% over fiscal 2011, primarily due to lower gas prices realized during the 4th quarter, as well as reduced production volumes during the first and second quarter as a result of maintenance issues. In addition, revenues (reported in Canadian dollars) were also negatively impacted by a decline in the value of the US dollar during the fiscal year.

Royalties

Royalties as a percentage of petroleum and natural gas sales were 17% during the fourth quarter, as compared to 19% in the previous quarter and 20% in the comparable period of the prior year. Royalties vary for each producing well causing fluctuations in the average royalty rates as production from the various wells fluctuates.

Operating costs

Operating expenses include all normal operating costs as well as workover costs for both the Gordon Creek and the Rush County projects. Fourth quarter costs increased 154% over the third quarter of the year and increased 29% over the corresponding period in fiscal 2011 due primarily to the cost of an additional compressor lease commencing in the fourth quarter of fiscal 2012, as well as annual property taxes paid in the fourth quarter.

OTHER INCOME STATEMENT ITEMS

General and administrative

General and administrative costs include such items as office rent, accounting fees, legal fees, professional and consulting fees, filing fees, salaries and wages, transfer agent fees, travel costs, and investor relations, as well as general office expenses.

	Three Months Ended			Year Ended	
	January 31, 2012	October 31, 2011	January 31, 2011	January 31, 2012	January 31, 2011
Reported amount	$ 493,710	$ 296,589	$ 288,411	$ 1,220,046	$ 971,741
G&A ($/boe)	$ 52.51	$ 28.75	$ 35.75	$ 33.90	$ 25.43

G&A expenses increased 66% in the fourth quarter of fiscal 2012 as compared to the immediately preceding quarter and were 71% higher than the comparable quarter of the prior year. G&A expenses for the year increased 26% over the prior fiscal year. The higher G&A expenses were partially attributable to increased professional and consulting fees accrued for work relating to the year-end financial statement audit (including IFRS conversion costs), tax returns and reserve report. The Company also incurred increased professional fees and related expenses during third and fourth quarters of the current year as a result of the implementation of the development drilling program at Gordon Creek.

Finance costs

	Three Months Ended			Year Ended	
	January 31, 2012	October 31, 2011	January 31, 2011	January 31, 2012	January 31, 2011
Reported amount	$ 836,110	$ 2,311,120	$ 546,223	$ 3,912,962	$ 1,533,729
Expense per sales volume ($/boe)	$ 88.94	$ 224.02	$ 67.71	$ 108.71	$ 40.14

Interest charges for the year include interest incurred on short term debt of $103,328 (2011 - $291,706), and interest paid on convertible debentures of approximately $17,443 (2011 - $195,084).

Interest paid on gas linked debentures (see "Long Term Debt" below) during the year was $1,456,241 (2011 - $325,877). Included in the amount of interest paid on gas linked debentures is the fair value of common shares issued as quarterly interest totaling $806,554.

Also included in the Interest, accretion and debt service costs expense are debt service costs of approximately $1,670,663 (2011 - $653,807). This amount included cash commissions of $250,000 as well as non-cash charges of $333,333 related to the imputed fair value of common shares issued as advisory fees, $1,087,330 related to the imputed fair value of warrants issued in connection with the retirement of the Company's credit facility with Macquarie Bank $1,087,330 and accretion on debenture transaction costs of $576,672 (2011 - $100,285) is included in the expense.

Accretion of decommissioning costs of $91,627 (2011 - $12,155) is included in finance costs.

The fourth quarter expense increased 53% compared to the fourth quarter of fiscal 2011, due to the cost of accretion on the debentures.

Depletion and depreciation

	Three Months Ended January 31, 2012	October 31, 2011	January 31, 2011	Year Ended January 31, 2012	January 31, 2011
Reported amount	$ 37,488	$ 69,530	$ 48,765	$ 202,400	$ 209,738
Expense per sales volume ($/boe)	$ 3.99	$ 6.74	$ 6.04	$ 5.62	$ 5.49

Depletion and depreciation is primarily associated with the Gordon Creek field. The net carrying value of the development or production assets is depleted using the unit-of-production method by reference to the ratio of production in the period over the related proven and probable reserves while also taking into account estimated future development costs necessary to bring those reserves into production. Changes in depletion and depreciation expense are consistent with the changes in production over previous quarters.

Unrealized foreign exchange gain

At the end of fiscal 2012 the Company had foreign exchange loss of $16,850. This loss pertains to the repayment of short-term debt denominated in U.S. currency. The foreign exchange loss is due to a weaker Canadian dollar at January 31, 2012 than at January 31, 2011.

Stock-based compensation

In accordance with IFRS 2, the fair value of each option granted during the period is estimated on the date of the grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	January 31, 2012	January 31, 2011
Fair value per share	$ 0.23	$ 0.15
Dividend yield	0%	0%
Interest rate	1.80%	1.94%
Expected life	5 years	3 years
Forfeiture Rate	17.60%	9.88%
Volatility	133%	155%

COMMITMENTS

The Company is contractually obligated to drill 50 additional wells (48 at year-end) and workover 5 standing wells on the Gordon Creek Property under the terms of its commodity stream production payment agreement with Sandstorm. Under the terms of the amended commodity stream production payment agreement with Sandstorm the Company is obligated to drill to drill 15 wells and complete 5 workovers by December 31, 2012 with the remaining 35 wells to be drilled by December 31, 2013. The Company leases its office premises for which minimum lease payments are due.

The following table summarizes the Company's outstanding obligations subsequent to signing the amended the commodity stream production payment agreement with Sandstorm.

Fiscal	Amount
2013	$ 12,886,854
2014	29,829,616
Thereafter	-
	$ 42,716,470

RISKS AND TRENDS

Demand for natural gas has traditionally been highly cyclical and somewhat predictable. Demand for, and pricing of, natural gas has traditionally been highest during the coldest months of winter. The primary driver for this cyclicality is the need for residential and commercial heating. Because natural gas is increasingly being used to generate electricity, increased electrical demand often means increased natural gas demand and pricing. This results in a smaller spike in natural gas demand during the warmest months of the year, as electrical demand for space cooling increases. Accordingly, the spring and fall “shoulder seasons” are typically becoming the periods of lowest natural gas prices.

Unconventional natural gas reserves and production have steadily increased in the United States over the past few years as a result of new horizontal drilling and “multi-frac” stimulation technologies that have allowed the commercialization of several large shale gas formations. This has caused downward pressure on gas prices. This downward pressure has been mitigated somewhat by the decrease in conventional gas drilling as well as increasing overall demand coincident with the ongoing economic recovery. Long term, there is an ongoing push to switch to natural gas for energy generation and transportation as a cleaner burning and potentially less expensive alternative to coal and oil, however the timing and extent of this shift is uncertain.

Although the Company has no set policy concerning hedges, the management may utilize various techniques to mitigate financial risks including hedging contracts, other financial instruments, and/or fixed price forward sales contracts to reduce corporate risk in certain situations. Effective April 1 to October 31, 2011 the Company was entered in a fixed price contract in place to sell 200 Mcf per day at $3.98 per Mcf. The Company has not entered into any fixed price contracts beyond January 31, 2012.

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

The Company’s principal risks include finding and developing economic hydrocarbon reserves efficiently and the ability to fund the required capital programs. The hydrocarbon purchase agreement with Sandstorm Metals & Energy Ltd. will fund the next phase of the Company’s development activities at Gordon Creek, however further capital will be required as the Company enters into subsequent phases of development and fulfills its drilling commitments to Sandstorm. The Company anticipates that future capital requirements will be funded through a combination of internal cash flow, debt, joint venture and equity financing. There is no assurance that financing will be available on terms acceptable to the Company to meet its capital requirements. If any components of the Company’s business plan are missing, the Company may not be able to exercise the entire business plan.

These risk factors should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause results or events to differ materially from forecast results.

Safety and Environment

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. The Company maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

LIQUIDITY AND CAPITAL RESOURCES

The Company's traditional sources of funding included the issuance of equity securities for cash, primarily through private placements and debt financing. The Company has issued debentures and common shares pursuant to private placement financings and exercise of warrants and options. The Company's access to exploration financing when the financing is not transaction specific is always uncertain. There can be no assurance of the continued access to significant equity financing.

During the year, the Company entered into a US$25 million commodity stream production payment agreement with Sandstorm Metals & Energy Ltd. ("Sandstorm") whereby Sandstorm has the right to purchase 35% of the Company's Gordon Creek natural gas production at a price of $1.00 per Mcf plus 20% of the amount by which the Gordon Creek field gate price exceeds $4.00. Pursuant to the agreement, the Company is obligated to drill 50 additional wells and workover 5 standing wells on the Gordon Creek Property, while Sandstorm advanced $15 million to the Company and will advance a further US$10 million in fiscal 2013. In order to secure the further advance of US$10 million the Company must drill 15 wells and complete 5 workovers by December 31, 2012. The remaining 35 wells are to be drilled by December 31, 2013. If these obligations are not meet the Company would be in default and owe Sandstorm amounts advanced or recovered from Sandstorm less production provided to Sandstorm, a value of $14,978,631 as at January 31, 2012. These circumstances lend significant doubt as to the ability of the Company to meet its obligations as they come due, and, accordingly, the appropriateness of the use of accounting principles applicable to a going concern (see note 2 of the consolidated financial statements). The Company has also provided Sandstorm with minimum annual cash flow and/or production guarantees for the years 2013 through 2018.

Until December 31, 2013, the Company has the option to repurchase 50% of the commodity stream by making a $US16.25 million payment to Sandstorm, upon receipt of which, the percentage of natural gas Sandstorm will be entitled to purchase will decrease to 17.5%. If the Company drills additional wells on the Gordon Creek Property over and above the minimum 50 net wells, the Sandstorm has the option to have production from the additional net wells form a part of the commodity stream by providing additional production payment advances to the Company at an agreed amount per well.

Subsequent to year-end, the Company and Sandstorm amended the commodity stream production payment agreement whereby all minimum cash flow guarantees and drilling commitments at Gordon Creek will be deferred by one year. As consideration for this deferral, in March 2013, Thunderbird will issue to Sandstorm $2.55 million of Thunderbird shares determined at a deemed price equivalent to 50 day volume weighted average trading price prior to issuance. Under the amended agreement, the Company has provided Sandstorm with minimum annual before tax cash flows guarantees earned through the sale of their 35% share of natural gas produced in Gordon Creek. The guarantee is the lesser of $2.3 million or 790mmcf by December 31, 2013, $5.1 million or 1740mmcf in calendar 2014, $4.6 million or 1560mmcf in calendar 2015, $4.2 million or 1410mmcf in calendar 2016, $3.8 million or 1260mmcf in calendar 2017, $3.3 million or 1140mmcf in calendar 2018 and $1.7 million or 590mmcf in calendar 2019. The Sandstorm Agreement provides that the cash flow guarantees will not apply in years where agreed production levels are achieved.

As at May 30, 2012 the Company has drilled 8 wells which are awaiting completion and production testing. A program consisting of completions and standing well workovers is scheduled to commence in the second quarter of the current fiscal year. The Company anticipates raising additional capital to complete its commitments to Sandstorm, by way of debt and/or equity. These funding arrangements are not yet in place, but given its external reserve engineer proved plus probable value discounted at 10% of approximately $70.0 million, the Company is optimistic that additional funding can be secured. There is no assurance that the initiatives undertaken by management will be successful.

At January 31, 2012, the Company had cash of $7,628,701 (January 31, 2011 - $62,810) and working capital of $7,854,037 (January 31, 2011 – working capital deficiency $1,662,298).

With the exception of the obligations to drill 50 wells and complete 5 workover operations pursuant to the Sandstorm Agreement outlined above, in the amount of $12.8 million for fiscal 2013 and $29.8 million for fiscal

2014, the Company had no commitments for capital expenditures as of January 31, 2012. The Company has no lines of credit or other sources of financing which have been arranged at this time, other than those listed below.

Long Term Debt

The Company issued $7.5 million in fiscal 2010 and $2.5 million in fiscal 2011 principal amount of three year, secured, natural gas linked debentures. The debentures bear interest at a base rate of 15% per annum with an adjustment provision whereby a 1% interest premium is added each quarter for every US$0.50 by which the price of natural gas as published by the Henry Hub exceeds US$5.00, capped at 25% per annum. One-half of each quarterly interest payment will be paid in fully paid common shares of the Company at a deemed price per interest share equal to the greater of (i) a 10% discount to the volume weighted average trading price of the Company's common shares on the TSX Venture Exchange over the quarter and (ii) the discounted market price of the Company's common shares. The purchasers of the gas linked debentures were also issued two detachable transferable warrants for every $1.00 of principal amount to purchase up to 20,000,000 common shares of the Company at escalating prices between $0.30 and $0.50 per share until October 31, 2013. The Company paid a 7.5% finder's fee in respect of a portion of the debenture issuance and issued non-transferable finder's warrants to purchase up to 2,161,250 common shares of the Company at a price of $0.20 per share until October 31, 2013.

Convertible debentures

During the year, the Company repaid the outstanding convertible debentures with the face value of $515,000 issued in December of 2008.

TRANSACTIONS WITH RELATED PARTIES

Related party transactions include the following:

		Year ended January 31, 2012	2011
Consulting fees paid or accrued to companies controlled by directors	$	246,800	$ 233,375
General and administrative expenses reimbursed to companies with common directors		162,894	106,373

Amounts due to related parties includes $69,161 (January 31, 2011 - $211,174) due to officers and directors and companies with common directors. Amounts due to related parties include an unsecured short-term loan payable and accrued interest owed to directors of the Company of $nil (2011 - $88,500). Included in the debentures is $2,629,000 held by related parties.

During the year, the Company completed a brokered private placement with a related party in which was partially settled through a related party loan in the amount of $77,910. The transaction is considered under the scope of IFRS 2 – Share-based payment, and no financial asset is recognized on the balance sheet. The fair value of the loan was determined using the Black-Scholes valuation model and an expense was is included in share based compensation (note 16).

All of the above noted transactions have been in the normal course of operations and are recorded at the exchange amount.

QUARTERLY FINANCIAL INFORMATION *(unaudited)*

Income Statement:	Q4 2012	Q3 2012	Q2 2012	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011
Net Revenues after Royalties	193,043	210,478	204,939	173,500	193,876	231,878	223,446	255,911
Expenses	2,122,275	2,867,148	924,276	657,644	1,129,104	1,113,340	716,402	641,252
Net loss for the period	(1,929,232)	(2,656,670)	(719,337)	(484,144)	(935,228)	(881,462)	(492,956)	(385,341)
Basic and diluted loss per share	(0.02)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Weighted average number of shares outstanding (thousands)	79,985	78,468	75,297	73,174	71,926	69,864	67,079	67,079

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments recognized in the balance sheet consist of cash, restricted cash, accounts receivable, accounts payable and accrued liabilities, due to related parties, short term debt, and debentures.

a) Fair value of financial instruments

The Company's financial assets and liabilities are comprised of cash, amounts receivable, prepaid expenses and advances, restricted cash, accounts payable and accrued liabilities, due to related parties, short-term debt, debentures and the financing deposit.

The Company classifies the fair value of these transactions according to the following fair value hierarchy based on the amount of observable inputs used to value the instrument:

· Level 1 – Values are based on unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date.

· Level 2 – Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace. Prices in Level 2 are either directly or indirectly observable as of the reporting date.

· Level 3 – Values are based on prices or valuation techniques that are not based on observable market data.

Accordingly, all the Company's financial assets and liabilities are classified as Level 1. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

b) Credit risk

Credit risk is the risk of an unexpected loss if a customer or third party to a financial instrument fails to meet its contractual obligations, and arises principally from the Corporation's joint venture partners and oil and natural gas marketers.

The carrying amount of the accounts receivable represents the maximum credit exposure. The Company has an allowance for doubtful accounts as at January 31, 2012 of nil and January 31, 2011 in the amount of US$72,940.

c) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Company's reputation.

The Company expects to satisfy obligations under accounts payable, amounts due to related parties, and short-term debt in less than one year through cash flows from operations and new financing. The timing of cash outflows relating to the financial liabilities is outlined below:

	Within 1 Year	After 1 Year	Total
Accounts payable and accrued liabilities	$ 2,150,317	$ -	$ 2,150,317
Due to related parties (note 19)	69,161	-	69,161
Debenture (note 14)	-	8,242,700	8,242,700
Financing Deposit (note 15)	-	14,978,631	14,978,631
Total	$ 2,219,478	$ 23,221,331	$ 25,440,809

The Company's capital programs are primarily funded by cash obtained through operations, equity issuances, debentures (note 14) and a financing deposit (note 15). The Company requires sufficient cash to fund capital programs necessary to maintain or increase production and develop reserves and to potentially acquire strategic assets.

d) Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices and interest rates will affect the Company's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

i. Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange risks. The Company is exposed to foreign currency fluctuations on transactions conducted in foreign currencies and in the carrying value of its foreign subsidiary. As of January 31, 2012, if the Canadian dollar had changed five percent against the United States dollar with all other variables held constant, the effect on net income for the year would have changed by approximately $180,000, while the effect on comprehensive income for the year would have been approximately $900,000.

The Company had no forward exchange rate contracts in place as at or during the period ended January 31, 2012.

ii. Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. The Company may enter into oil and natural gas contracts to protect its cash flow on future sales. The contracts reduce the volatility in sales revenue by locking in prices with respect to future deliveries of oil and natural gas. During the year, the Company had a fixed price contract to sell 200 Mcf/day at a fixed price of $3.98 per Mcf from April 1, 2011 until October 31, 2011. The Company's exposure to changes in natural gas prices to a plus or minus $1.00 change would affect the loss by approximately $205,000 while a $1.00 change in the price of oil would insignificantly affect the loss for the year ended January 31, 2012.

iii. Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk on its debentures which bears an interest rate with at a base rate of 15% per annum with an adjustment provision whereby a 1% interest is added each quarter for every US$0.50 by which the price of natural gas as published by the Henry Hub exceeds US$5.00, capped at 25% per annum. The Company estimates that a one percent change in the interest rate on the debentures would impact the net loss and cash flows from operations for the year by approximately $87,500 based on the average amount of debt outstanding during the year. The Company has no interest rate hedges or swaps outstanding at January 31, 2012.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the interim consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities at the date of the financial statements and for the periods presented. Such estimates primarily related to unsettled transactions and events as at the date of the interim consolidated financial statements. Actual results may differ from those estimates. Significant estimates and judgments made by Management in the preparation of these interim consolidated financial statements are outlined below.

Fair value of oil and gas properties, depletion and depreciation and amounts used in impairment calculations are based on estimates of oil and natural gas reserves, future prices and future costs required to develop those reserves. By nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact of the differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

Petroleum and natural gas properties, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units ("CGUs") based on their ability to generate largely independent cash flows and are used for impairment testing. The determination of the Company's CGUs is subject to management's judgment.

The decision to transfer exploration and evaluation assts to property and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and probable reserves.

Amounts recorded in decommissioning liabilities and the related accretion expense require the use of estimates including timing of asset retirements, site remediation, discount rate, inflation rate and related cash flows. Provisions are recognized in the period when it becomes probable that there will be a future cash outflow.
Compensation costs accrued for share-based compensation plans are subject to the estimated fair values, forfeiture rates.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. Deferred tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS (“IFRS”)

The consolidated financial statements for the year ended January 31, 2012, including required comparative information, have been prepared in accordance with IFRS applicable to the preparation of annual financial statements, including IFRS 1 (First-time Adoption of IFRS). Previously, the Company prepared its Interim and Annual Consolidated Financial Statements in accordance with Canadian GAAP. The adoption of IFRS has not had any impact on the Company’s operations, strategic decisions and funds flow from operations.

The Company’s IFRS accounting policies are provided in Note 4 to the consolidated financial statements for the year ended January 31, 2012 and, in addition Note 26 presents reconciliations between the Company’s 2011 previous GAAP results and the 2011 IFRS results. The reconciliations include the Consolidated Balance Sheets as at February 1, 2010 and January 31, 2011, and the Consolidated Statements of Comprehensive Loss for the year ended January 31, 2011.

Accounting Policies Changes

The following discussion explains the significant differences between the Company’s previous Canadian GAAP accounting policies and those applied under IFRS. IFRS policies have been retrospectively and consistently applied except where specific IFRS 1 optional and mandatory exemptions permitted an alternative treatment upon transition to IFRS for first-time adopters.

Exploration and evaluation assets

Exploration and evaluation assets as February 1, 2010 were deemed to be US$999,977 (Cdn $1,070,876), representing the unproved properties balance under previous GAAP. This balance included US$16,647 (Cdn $17,827) in previously capitalized legal costs incurred in setting up the acquisition of property. As these expenditures were incurred prior to obtaining legal rights to explore the property, under IFRS the Company is required to expenses pre-license costs. Therefore at February 1, 2010, the Company reclassified US$983,330 (Cdn $1,053,049) from property and equipment to exploration and evaluation assets and US$16,647 (Cdn $17,827) to the deficit as at February 1, 2010.

Under previous GAAP, exploration and evaluation expenditures were capitalized as property and equipment in accordance with the CICA's full cost accounting guidelines. Under IFRS, the Company capitalizes these costs initially as exploration and evaluation assets. When an area is determined to be technically feasible and commercially viable, the accumulated costs are transferred to property and equipment. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to net earnings as exploration and evaluation expense.

Decommissioning liability
Under previous GAAP, the Company's asset retirement obligation was discounted using an average credit-adjusted risk free rate. Under IFRS, the Company discounted its decommissioning liability using an average risk free rate. As at February 1, 2010, the differences resulted in an increase in the decommissioning liability by US$93,187 (Cdn $99,793), with a corresponding decrease to accumulated deficit.

Depreciation and depletion
Under previous GAAP, development costs were depleted using unit-of-production method based on proved reserves for each country cost centre. Under IFRS, development costs are depleted using the unit-of-production method based on proved and probable reserves at the established CGU. This resulted in a $203,176 decrease to the Company's depreciation and depletion expense for the year ended January 31, 2011.

Impairment
Under IFRS, the Company is required to test for impairment at the CGU level. Upon review of impairment on the date of transition, February 1, 2010, the Company determined that the Company's investment in its Rush County, Kansas oil project was impaired resulting in a charge against the accumulated deficit in the amount of US$1,002,775 (Cdn $1,073,872).

Change in estimates
Under IFRS the depreciation method applied to an asset must be reviewed at least at each financial year-end and any significant change in the expected pattern of consumption should be accounted for as a change in an accounting estimate. Therefore upon transition to IFRS the Company reviewed its depreciation method and determined that a straight line depreciation policy for corporate and production assets was more appropriate. The change in estimate resulted in a decrease to Property and Equipment of $8,875 with a corresponding increase to accumulated deficit.

Share-Based Compensation
To conform with IFRS, as at the transition date the Company revalued its contributed surplus arising from share-based compensation to recognize the impact of estimating forfeitures and changing to graded vesting required under whereby each tranche is individually valued with greater costs recognized up front instead of equally over the vesting period, as was the case under previous GAAP.

Transaction Costs
In accordance with IAS 39 – *Financial Instruments –recognition and measurement*, transaction costs are directly attributable to the issuance of the debentures are initially recognized against the financial liability and are expensed over the term of the life debt instrument. Under GAAP the Company had been expensing transaction costs as incurred.

Recent Pronouncements Issued
The Company has reviewed new and revised accounting pronouncements that have been issued but are not yet

effective and determined that the following may have an impact on the Company:

IFRS 9 - *Financial Instruments*
The IASB intends to replace IAS 39, Financial Instruments: Recognition and Measurements, with IFRS 9, Financial Instruments. IFRS 9 will be published in six phases, of which the first phase has been published.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used. For financial liabilities, the approach to the fair value option may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2015, but is available for early adoption. The Corporation has yet to assess the full impact of IFRS 9.

IFRS 10 – *Consolidation*
As of February 1, 2013, the Company will be required to adopt IFRS 10 which requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12 – *Consolidation – Special Purpose Entities*, and parts of IAS 27 – *Consolidated and Separate Financial Statements*. The Company has yet to assess the full impact of IFRS 10.

IFRS 11 – *Joint Arrangements*
As of February 1, 2013, the Company will be required to adopt IFRS 11 which requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operations. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31 – *Interests in Joint Ventures*, and SIC 13 – *Jointly Controlled Entities – Non-monetary Contributions by Venturers*. The Company has yet to assess the full impact of IFRS 11.

IFRS 12 – *Disclosure of Interests in Other Entities*
As of February 1, 2013, the Company will be required to adopt IFRS 12 which establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities. The Company has yet to assess the full impact of IFRS 12.

IFRS 13 – *Fair Value Measurement*
As of February 1, 2013, the Company will be required to adopt IFRS 13, a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. This new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. The Company has yet to assess the full impact of IFRS 13.

Amendments to Other Standards
In addition, there have been amendments to existing standards, including IAS 27 – *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*. IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has

been amended to include joint ventures in its scope to address the changes in IFRS 10 to 13. Both of the amended standards are not applicable until January 1, 2013. The Company has yet to assess the full impact of these amendments.

FORWARD LOOKING STATEMENTS

This discussion includes certain statements that may be deemed “forward-looking statement”. Forward-looking statements or information do not relate strictly to historical or current facts, and can be identified by words such as “anticipate”, “continue”, “estimate”, “expect”, “forecast”, “may”, “will”, “plan”, “project”, “should”, “believe”, “intend”, or similar expressions. These statements represent managements’ reasonable projections, expectations and estimates as of the date of this document, but undue reliance should not be placed upon them as they are derived from numerous assumptions. These assumptions are subject to known and unknown risks and uncertainties, including the business risk discussed in the MD&A, which may cause actual performance and financial results to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements.

Such forward-looking statements or information are based on a number of assumptions which may prove to be incorrect. In addition to the other assumptions identified in this document, assumptions have been made regarding, among other things:

- Future oil and gas supply and prices;
- Drilling and operational results consistent with expectations;
- The ability for the Company to obtain financing on acceptable terms;
- Currency, exchange and interest rates;
- Cash flow consistent with expectations;
- The ability of the Company to obtain equipment, services and supplies in a timely manner to carry out its activities;

The forward looking information in this document is subject to significant risks and uncertainties and is based on a number of material factors and assumptions which may prove to be incorrect; including but not limited to the following assumptions:

- Normal risks common to the petroleum and natural gas industry including various operational risk in exploring for, developing and producing petroleum and natural gas and market demand
- Risks and uncertainties involving geology of oil and gas deposits
- Revisions, amendments or changes to capital expenditure plans including exploration, development and exploitation projects
- Uncertainties as to the availability and cost of appropriate financing alternatives on acceptable terms, including the Company’s ability to extend its credit facility on an ongoing basis
- Potential changes in income tax regulations, governmental policies, rules, practices or approval process changes, or delays, or enhancements
- Ability to attract and retain qualified professional employees
- Fluctuations in oil and gas prices, foreign currency exchange rates and interest rates
- The uncertainty of reserve estimate and reserve life
- The uncertainty of estimates and projections relating to future production, costs and expenses
- Health, safety and environmental risks

Statements relating to “reserves” or “resources” are by their nature 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.

Although the company believes the expectations expressed in such forward-looking statements or information are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Accordingly, readers should not place undue reliance on forward-looking information.

The forward-looking statements or information contained in this document represent our views as of the date hereof and as such information should not be relied upon as representing our views as of any date subsequent to the date of this document. The Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Non-IFRS Measures

In this document, the Company uses the terms "funds flow from operations" and "operating income" which do not have any standardized meaning under IFRS and may not be comparable to similar measures presented by other companies.

"Funds flow from operations" refers to the cash flow from operating activities before net changes in operating working capital. The most direct comparable measure to "funds flow from operations" calculated in accordance with IFRS is the cash flow from operating activities. "Funds flow from operations" can be reconciled to cash flow from operating activities by adding (deducting) the net change in working capital as shown in the consolidated statements of cash flow.

"Operating income" is equal to petroleum and natural gas sales minus royalties and operating costs. Management believes that the Non-IFRS measures provide useful information to investors as indicative measures of performance.

Investors are cautioned that the Non-IFRS measures should not be considered in isolation or construed as alternatives to their most directly comparable measure calculated in accordance with IFRS, as set forth above, or other measures of financial performance calculated in accordance with reporting standards.

BOE Presentation

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of gas ("Mcf") to one barrel of oil ("bbl") (6 Mcf: 1 bbl) is used as an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting natural gas to oil in the ratio of six Mcf of gas to one barrel of oil. Readers should be aware that historical results are not necessarily indicative of future performance.

DISCLOSURE OF OUTSTANDING SHARE DATA

As at May 30, 2012 the Company had the following common shares and stock options outstanding:

Common Shares	82,382,500
Share Purchase Warrants	35,841,459
Stock Options	6,515,000

There are no shares held in escrow.

"CAMERON WHITE"

Cameron White, Chief Executive Officer

"STEPHEN CHEIKES"

Steven Cheikes, Director