UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 20-F /A
(Amendment No. 1)

¨ REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR (g) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended August 31, 2011

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

¨ SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Date of event requiring this shell company report ______________________________

For the transition period from__________________to_______________

Commission File Number: 0-53646

EAGLEFORD ENERGY INC.
(Exact name of Registrant as specified in its charter)

Ontario, Canada
(Jurisdiction of incorporation or organization)

1 King Street West, Suite 1505
Toronto, Ontario, Canada, M5H 1A1
(Address of principal executive offices)

James Cassina, Telephone (416) 364-4039, Fax (416) 364-8244
1 King Street West, Suite 1505, Toronto, Ontario, Canada, M5H 1A1
(Name, telephone, e-mail and/or facsimile number and address of company contact person)

Securities registered or to be registered pursuant to section 12(b) of the Act: **None**

Securities registered or to be registered pursuant to Section 12(g) of the Act: **Common Stock, no par value**
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**
(Title of Class)

The number of outstanding shares of the issuer's common stock as of August 31, 2011 was 34,716,076 shares.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

If this report is an annual or a transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP ¨	International Financial Reporting Standards by the International Accounting Standards Board ¨	Other x

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow. ‘

Item 17 x Item 18 ¨

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

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EXPLANATORY NOTE

Eagleford Energy Inc. ("Eagleford" or the "Company") is filing this Amendment No. 1 to its Annual Report on Form 20-F for the year ended August 31, 2011, which was originally filed with the Securities and Exchange Commission on February 16, 2012. This Amendment No. 1 is being filed to include Exhibit 4.17, Evaluation of the P&NG Reserves of the Company as of August 31, 2011. Except as described above, no other amendments, disclosures, alterations or updates are being made to the Annual Report on 20-F as originally filed. In addition, as required by Rule 12b-15 under the Exchange Act, new certifications of our principal executive and financial officer are filed as exhibits to this Amendment No. 1.

GENERAL

In this Annual Report, references to "we", "us", "our", the "Company", and "Eagleford" mean Eagleford Energy Inc., and its subsidiaries, unless the context requires otherwise.

We use the Canadian dollar as our reporting currency and our financial statements are prepared in accordance with Canadian generally accepted accounting principles. Note 17to our annual consolidated financial statements provides a reconciliation of our financial statements to United States generally accepted accounting principles. All monetary references in this document are to Canadian dollars, unless otherwise indicated. All references in this document to "dollars" or "$" or "CDN$" mean Canadian dollars, unless otherwise indicated, and references to "US$" mean United States dollars.

Except as noted, the information set forth in this Annual Report is as of January 31, 2012 and all information included in this document should only be considered accurate as of such date. Our business, financial condition or results of operations may have changed since that date.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

Much of the information included in this Annual Report is based upon estimates, projections or other "forward-looking statements". Such forward-looking statements include any projections or estimates made by us and our management in connection with our business operations. These statements relate to future events or our future financial performance. In some cases you can identify forward-looking statements by terminology such as "may", "should", "expects", "plans", "anticipates", "believes", "estimates", "predicts", "potential" or "continue" or the negative of those terms or other comparable terminology. While these forward-looking statements, and any assumptions upon which they are based, are made in good faith and reflect our current judgment regarding the direction of our business, actual results will almost always vary, sometimes materially, from any estimates, predictions, projections, assumptions or other future performance suggested herein. Such estimates, projections or other forward-looking statements involve various risks and uncertainties and other factors, including the risks in the section titled "Risk Factors" below, which may cause our actual results, levels of activities, performance or achievements to be materially different from any future results, levels of activity, performance or achievements expressed or implied by these forward-looking statements. We caution the reader that important factors in some cases have affected and, in the future, could materially affect actual results and cause actual results to differ materially from the results expressed in any such estimates, projections or other forward-looking statements. Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements. Except as required by applicable law, including the securities laws of the United States, we do not intend to update any of the forward-looking statements to conform those statements to actual results.

The statements contained in Item 4 – "Information on the Company", Item 5 – "Operating and Financial Review and Prospects" and Item 11 – "Quantitative and Qualitative Disclosures About Market Risk" are inherently subject to a variety of risks and uncertainties that could cause actual results, performance or achievements to differ significantly.

PART I

ITEM 1 IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

A. DIRECTORS AND SENIOR MANAGEMENT

Not applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

B. ADVISERS

Not applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

C. AUDITORS

Not applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

ITEM 2 OFFER STATISTICS AND EXPECTED TIMETABLE

A. OFFER STATISTICS

Not applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

B. METHOD AND EXPECTED TIMETABLE

Not applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

ITEM 3 KEY INFORMATION

A. SELECTED FINANCIAL DATA

The following table presents selected financial data derived from our Audited Consolidated Financial Statements for the fiscal years ended August 31, 2011, 2010, 2009, 2008 and 2007. You should read this information in conjunction with our Audited Consolidated Financial Statements and related notes (Item 17), as well as Item 4: "Information on the Company" and Item 5: "Operating and Financial Review and Prospects" of this Annual Report.

Our consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") in Canadian dollars. Note 17 to the audited annual consolidated financial statements provides descriptions of material measurement differences between Canadian GAAP and US generally accepted accounting principles ("US GAAP") as they relate to us and a reconciliation of our consolidated financial statements to US GAAP.

The selected consolidated statement of operations data set forth below for the years ended August 31, 2011, 2010, 2009, 2008 and 2007and the selected consolidated balance sheet information set forth below as of August 31, 2011, 2010, 2009, 2008 and 2007 is derived from our consolidated financial statements, which have been audited by Schwartz Levitsky Feldman LLP, Chartered Accountants, Toronto, Canada all of which are attached to and forming part of this Annual Report under Item 17 – Financial Statements.

EAGLEFORD ENERGY INC.
Presented Pursuant to Canadian Generally Accepted Accounting Principles
(STATED IN CANADIAN DOLLARS)

	YEARS ENDED AUGUST 31,				
CONSOLIDATED STATEMENT OF OPERATIONS DATA	**2011**	**2010**	**2009**	**2008**	**2007**
Revenue	$ 71,786	$ 105,375	$ 56,199	$ 292	$ 637
Income (loss) from oil and gas operations	(18,961)	(35,586)	(53,626)	268	541
Administrative expenses	741,596	653,153	276,815	50,782	40,691
Operating loss for the year	760,557	(688,739)	(330,441)	(50,514)	(40,150)
Interest income	-	30	1,580	-	205
Gain on disposal of marketable securities	8,000	-	-	-	-
Net loss and comprehensive loss for the year	(752,557)	(688,709)	(328,861)	(50,514)	(39,945)
Loss per common share basic and diluted	(0.0.24)	(0.028)	(0.019)	(0.006)	(0.006)
Weighted average common shares outstanding	31,927,228	24,687,130	17,646,295	7,955,482	6,396,739
CONSOLIDATED BALANCE SHEET INFORMATION					
Working capital (deficiency)	(4,870,621)	(744,262)	(137,372)	(93,634)	(483,860)
Total assets	9,478,226	6,107,452	600,327	208,486	9,746
Total shareholders' equity (deficiency)	4,220,299	4,239,777	265,994	(93,186)	(482,860)

The following table sets forth our selected consolidated financial data as set forth in the preceding table, as reconciled pursuant to United States Generally Accepted Accounting Principles:

EAGLEFORD ENERGY INC.
Presented Pursuant to United States Generally Accepted Accounting Principles
(STATED IN CANADIAN DOLLARS)

	YEARS ENDED AUGUST 31,				
CONSOLIDATED STATEMENT OF OPERATIONS DATA	**2011**	**2010**	**2009**	**2008**	**2007**
Revenue	$ 71,786	$ 105,375	$ 56,199	$ 292	$ 637
Income (loss) from oil and gas operations	(18,961)	(35,586)	(53,626)	268	541
Administrative expenses	741,596	653,153	276,815	50,782	40,691
Operating loss for the year	(760,557)	(688,739)	(330,441)	(50,514)	(40,150)
Interest income	-	30	1,580	-	205
Gain on disposal of marketable securities	8,000	-	-	-	-
Net loss and comprehensive loss according to Canadian GAAP	(752,557)	(688,709)	(328,861)	(50,514)	(39,945)
Additional impairment of oil and gas interests	(170,000)	(50,000)	(73,638)	-	-
Comprehensive loss according to US GAAP	(922,557)	(738,709)	(402,499)	(50,514)	(39,945)
Net loss per common share basic and diluted according to US GAAP	(0.029)	(0.030)	(0.023)	(0.006)	(0.006)
Shares used in the computation of basic and diluted earnings per share	31,927,228	24,687,130	17,646,295	7,955,482	6,396,739
CONSOLIDATED BALANCE SHEET INFORMATION					
Working capital (deficiency)	(4,870,621)	(744,262)	(137,372)	(93,634)	(483,860)
Total assets per Canadian GAAP	9,478,226	6,107,452	600,327	208,486	9,746
Additional impairment of oil and gas interests	(170,000)	(50,000)	(73,638)	-	-
Total assets per US GAAP	9,308,226	6,057,452	526,689	208,486	9,746
Total shareholders' equity (deficiency) per Canadian GAAP	4,220,299	4,239,777	265,994	(93,186)	(482,860)
Additional impairment of oil and gas interests	(170,000)	(50,000)	(73,638)	-	-
Total shareholders' equity (deficiency) per US GAAP	4,050,299	4,189,777	192,356	(93,186)	(482,860)
OTHER CONSOLIDATED FINANCIAL DATA					
Cash flow provided by (used in):					
Operating activities	53,157	(219,320)	(172,333)	(50,414)	(268)
Investing activities	(3,196,438)	(21,228)	80,499	-	-
Financing activities	3,264,771	111,419	62,013	252,188	-

Differences between Generally Accepted Accounting Principles (GAAP) in Canada and the United States
For the year ended August 31, 2011 the preparation of our Audited Consolidated Financial Statements in accordance with Canadian GAAP with a reconciliation to US GAAP recorded an additional impairment in oil and gas interests of $170,000 on the consolidated balance sheet and on the consolidated statement of operations and comprehensive loss. For the year ended August 31, 2010 the preparation of our Audited Consolidated Financial Statements in accordance with Canadian GAAP with a reconciliation to US GAAP recorded an additional impairment in oil and gas interests of $50,000 on the consolidated balance sheet and on the consolidated statement of operations and comprehensive loss.. For the year ended August 31, 2009 the preparation of our Audited Consolidated Financial Statements in accordance with Canadian GAAP with a reconciliation to US GAAP recorded an additional impairment in oil and gas interests of $73,638 on the consolidated balance sheet and on the consolidated statement of operations and comprehensive loss. For the years ended August 31, 2008 and 2007 the preparation of our Audited Consolidated Financial Statements in accordance with US GAAP would not have resulted in differences to the consolidated balance sheet or consolidated statement of operations and comprehensive loss from our Audited Consolidated Financial Statements prepared using Canadian GAAP. Recently Issued United States Accounting Standards are included in Note 17 to our August 31, 2011 Audited Consolidated Financial Statements.

Exchange Rate Information

The exchange rate between the Canadian dollar and the U.S. dollar was CDN$1.00 per US$1.005 (or US$1.005 per CDN$1.00) as of January 31, 2012.

The average exchange rates for the periods indicated below (based on the daily noon buying rate for cable transfers in New York City certified for customs purposes by the Federal Reserve Bank of New York) are as follows:

	YEARS ENDED AUGUST 31,				
	2011	2010	2009	2008	2007
Average exchange rate CDN$ per US$1.00	0.9783	1.0640	1.0967	1.0631	1.0560
Average exchange rate US$ per CDN$1.00	1.0217	0.9360	0.9033	0.9369	0.9440

The high and low exchange rates between the Canadian dollar and the U.S. dollar for each of the six months ended January 31, 2012 are as follows:

	Exchange rate CDN$ per US$1.00	
Month	Low	High
January 2012	0.9986	1.0246
December 2011	1.0106	1.0403
November 2011	1.0200	1.0487
October 2011	0.9932	1.0605
September 2011	0.9751	1.0389
August 2011	0.9593	0.9909

B. CAPITALIZATION AND INDEBTEDNESS

Not Applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

C. REASONS FOR THE OFFER AND USE OF PROCEEDS

Not Applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

D. RISK FACTORS

Our securities are highly speculative and subject to a number of risks. You should not consider an investment in our securities unless you are capable of sustaining an economic loss of the entire investment. In addition to the other information presented in this Annual Report, the following risk factors should be given special consideration when evaluating an investment in our securities.

General Risk Factors

Going Concern. We require additional capital which may not be available to us on acceptable terms, or at all. Both the exploration and development of oil and gas reserves can be capital-intensive businesses. We have accumulated significant losses and negative cash flows from operations in recent years which raises doubt as to the validity of the going concern assumption. As at August 31, 2011, we had a working capital deficiency of $4,870,621 and an accumulated deficit of $2,469,792. We do not have sufficient funds to meet our liabilities for the ensuing twelve months as they become due. In assessing whether the going concern assumption is appropriate, we take into account all available information about the future, which is at least, but not limited to, twelve months from August 31, 2011. Our ability to continue operations and fund its liabilities is dependent on our ability to secure additional financing and cash flow. We are pursuing such additional sources of financing and cash flow to fund our operations and obligations and while we have been successful in doing so in the past, there can be no assurance we will be able to do so in the future. We intend to satisfy any additional working capital requirements from cash flow and by raising capital through public or private sales of debt or equity securities, debt financing or short-term loans, or a combination of the foregoing. We have no current arrangements for obtaining additional capital, and may not be able to secure additional capital, or on terms which will not be objectionable to us or our shareholders. Under such circumstances, our failure or inability to obtain additional capital on acceptable terms or at all could have a material adverse effect on us.

We have a history of losses and a limited operating history as an oil and gas exploration and development company which makes it more difficult to evaluate our future prospects. To date, we have incurred significant losses. We have a limited operating history upon which any evaluation of us and our long-term prospects might be based. We are subject to the risks inherent in the oil and gas industry, as well as the more general risks inherent to the operation of an established business. We and our prospects must be considered in light of the risks, expenses and difficulties encountered by all companies engaged in the extremely volatile and competitive oil and gas markets. Any future success we might achieve will depend upon many factors, including factors, which may be beyond our control. These factors may include changes in technologies, price and product competition, developments and changes in the international oil and gas market, changes in our strategy, changes in expenses, fluctuations in foreign currency exchange rates, general economic conditions, and economic and regulatory conditions specific to the areas in which we compete. To address these risks, we must, among other things, comply with environmental regulations; expand our portfolio of proven oil and gas properties and negotiate additional working interests and prospect participations; and expand and replace depleting oil and gas reserves.

We have significant debt which may make it more difficult for us to obtain future financing or engage in business combination transactions. We have significant debt obligations. The degree to which this indebtedness could have consequences on our future prospects includes the effect of such debts on our ability to obtain financing for working capital, capital expenditures or acquisitions. The portion of available cash flow that will need to be dedicated to repayment of indebtedness will reduce funds available for expansion. If we are unable to meet our debt obligations through cash flow from operations, we may be required to refinance or adopt alternative strategies to reduce or delay capital expenditures, or seek additional equity capital.

Our future operating results are subject to fluctuation based upon factors outside of our control. Our operating results may in the future fluctuate significantly depending upon a number of factors including industry conditions, oil and gas prices, rate of drilling success, rates of production from completed wells and the timing of capital expenditures. Such variability could have a material adverse effect on our business, financial condition and results of operations. In addition, any failure or delay in the realization of expected cash flows from operating activities could limit our future ability to participate in exploration or to participate in economically attractive oil and gas projects.

Our operating results will be affected by foreign exchange rates. Since energy commodity prices are primarily priced in US dollars, a portion of our revenue stream and a portion of our expenses are incurred in US dollars and they are affected by U.S./Canadian dollar exchange rates. We do not hedge this exposure. While to date this exposure has not been material, it may become so in the future.

Our inability to manage our expected growth could have a material adverse effect on our business operations and prospects. We may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls. The ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expend, train and manage our employee base. The inability to deal with this growth could have a material adverse impact on our business, operations and prospects.

To compete in our industry, we must attract and retain qualified personnel. Our ability to continue our business and to develop a competitive edge in the marketplace depends, in large part, on our ability to attract and retain qualified management and personnel. Competition for such personnel is intense, and we may not be able to attract and retain such personnel which may negatively impact our share price. We do not have key-man insurance on any of our employees, directors or senior officers and we do not have written employment agreements with any of our employees, directors or senior officers.

We must continue to institute procedures designed to avoid potential conflicts involving our officers and directors. Some of our directors and officers are or may serve on the board of directors of other companies from time to time. Pursuant to the provisions of the Business Corporations Act (*Ontario*), our directors and senior officers must disclose material interests in any contract or transaction (or proposed contract or transaction) material to us. To avoid the possibility of conflicts of interest which may arise out of their fiduciary responsibilities to each of the boards, all such directors have agreed to abstain from voting with respect to a conflict of interest between the applicable companies. In appropriate cases, we will establish a special committee of independent directors to review a matter in which several directors, or members of management, may have a conflict.

We rely on the expertise of certain persons and must insure that these relationships are developed and maintained. We are dependent on the advice and project management skills of various consultants and joint venture partners contracted by us from time to time. Our failure to develop and maintain relationships with qualified consultants and joint venture partners will have a material adverse effect on our business and operating results.

We must indemnify our officers and directors against certain actions. Our articles contain provisions that state, subject to applicable law, we must indemnify every director or officer, subject to the limitations of the Business Corporations Act (*Ontario*), against all losses or liabilities that our directors or officers may sustain or incur in the execution of their duties. Our articles further state that no director or officer will be liable for any loss, damage or misfortune that may happen to, or be incurred by us in the execution of his duties if he acted honestly and in good faith with a view to our best interests. Such limitations on liability may reduce the likelihood of litigation against our officers and directors and may discourage or deter our shareholders from suing our officers and directors based upon breaches of their duties to us, though such an action, if successful, might otherwise benefit us and our shareholders.

We do not currently maintain a permanent place of business within the United States. A majority of our directors and officers are nationals or residents of countries other than the United States, and all or a substantial portion of such persons' assets are located outside the United States. As a result, it may be difficult for investors to enforce within the United States any judgments obtained against our company or our officers or directors, including judgments predicated upon the civil liability provisions of the securities laws of the United States or any state thereof.

The global financial crisis is expected to cause petroleum and natural gas prices to remain volatile for the near future. Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions are continuing -, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward. Petroleum and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Since our sole executive officer does not devote his full time to the performance of his Company duties, he may engage in other work activities to our detriment. James Cassina, our sole executive officer, devotes approximately 75% of his work time to the performance of his Company duties. Although he has an obligation to perform his duties in a manner consistent with our best interests and through his stock ownership in the Company, is incentivized to do so, may encounter conflicts regarding the availability and use of his work time. Although there are no such present conflicts, the development thereof could have a material adverse effect on us.

Risks Factors Relating to Our Common Stock

Our stockholders may have difficulty selling shares of our common stock as there is a limited public trading market for such stock. There is only a limited public market for our common stock, and no assurance can be given that a broad or active public trading market will develop in the future or, if developed, that it will be sustained. Our common stock trades on the Over-the-Counter Bulletin Board. In addition, our common stock has not been qualified under any applicable state blue-sky laws, and we are under no obligation to so qualify or register our common stock, or otherwise take action to improve the public market for such securities. Our common stock could have limited marketability due to the following factors, each of which could impair the timing, value and market for such securities: (i) lack of profits, (ii) need for additional capital, (ii) limited public market for such securities; (iii) the applicability of certain resale requirements under the Securities Act; and (iv) applicable blue sky laws and the other factors discussed in this Risk Factors section.

Possible volatility of stock price. The market price for our common stock may be volatile and is subject to significant fluctuations in response to a variety of factors, including the liquidity of the market for the common stock, variations in our quarterly operating results, regulatory or other changes in the oil and gas industry generally, announcements of business developments by us or our competitors, litigation, changes in operating costs and variations in general market conditions. Because we have a limited operating history, the market price for our common stock may be more volatile than that of a seasoned issuer. Changes in the market price of our securities may have no connection with our operating results. No predictions or projections can be made as to what the prevailing market price for our common stock will be at any time.

We do not anticipate paying dividends on our common stock. We presently plan to retain all available funds for use in our business, and therefore do not plan to pay any cash dividends with respect to our securities in the foreseeable future. Hence, investors in our common stock should not expect to receive any distribution of cash dividends with respect to such securities for the foreseeable future.

Our shareholders may experience dilution of their ownership interests because of our future issuance of additional shares of common stock. Our constating documents authorize the issuance of an unlimited number of shares of common stock, without par value. In the event that we are required to issue additional shares of common stock or securities exercisable for or convertible into additional shares of common stock, enter into private placements to raise financing through the sale of equity securities or acquire additional oil and gas property interests in the future from the issuance of shares of our common stock to acquire such interests, the interests of our existing shareholders will be diluted and existing shareholders may suffer dilution in their net book value per share depending on the price at which such securities are sold. If we do issue additional shares, it will cause a reduction in the proportionate ownership and voting power of all existing shareholders.

At the Annual and Special Meeting of Shareholders to be held on February 24, 2012, shareholders will be asked to approve a resolution permitting us to issue up 37,716,076 additional shares of common stock by way of private placements, acquisitions or equity credit lines to be completed on or before February 24, 2013.

At the Annual and Special Meeting of Shareholders to be held on February 24, 2012, shareholders will be asked to approve a resolution authorizing us to consolidate our issued and outstanding common shares on an up to one (1) for four (4) basis, or divide our issued and outstanding common shares on an up to four (4) for one (1) basis.

At the Annual and Special Meeting of Shareholders to be held on February 24, 2012, shareholders will be asked to approve a resolution authorizing us to increase the maximum aggregate number of common shares reserved for issuance under our stock option plan, as amended, to an amount not to exceed 20% of the total shares issued and outstanding of the Company as of the date of each option grant. As of January 25, 2011, the date of the Notice of Meeting and Management Information Circular the Company had 37,716,026 issued and outstanding shares.

As of the date of this Annual Report, no such options are issued.

Prospective investors in our Company are urged to seek independent investment advice. Independent legal, accounting or business advisors (i) have not been appointed by, and have not represented or held themselves out as representing the interests of prospective investors in connection with this Annual Report, and (ii) have not "expertized" or held themselves out as "expertizing" any portion of this Annual Report, nor is our legal counsel providing any opinion in connection with us, our business or the completeness or accuracy of this Annual Report. Neither we nor any of our respective officers, directors, employees or agents, including legal counsel, make any representation or expresses any opinion (i) with respect to the merits of an investment in our common stock, including without limitation the proposed value of our common stock; or (ii) that this Annual Report provides a complete or exhaustive description of us, our business or relevant risk factors which an investor may now or in the future deem pertinent in making his, her or its investment decision. Any prospective investor in our common stock is therefore urged to engage independent accountants, appraisers, attorneys and other advisors to (a) conduct such due diligence review as such investor may deem necessary and advisable, and (b) to provide such opinions with respect to the merits of an investment in our Company and applicable risk factors upon which such investor may deem necessary and advisable to rely. We will fully cooperate with any investor who desires to conduct such an independent analysis so long as we determine, in our sole discretion, that such cooperation is not unduly burdensome.

Applicable SEC rules governing the trading of "penny stocks" will limit the trading and liquidity of our common stock and may affect the trade price for our common stock. The Securities and Exchange Commission ("SEC") has adopted rules which generally define "penny stock" to be any equity security that has a market price (as defined) of less than US$5.00 per share or an exercise price of less than $5.00 per share, subject to certain exceptions. Our securities will be covered by the penny stock rules, which impose additional sales practice requirements on broker-dealers who sell to persons other than established customers and "accredited investors". The term "accredited investor" refers generally to institutions with assets in excess of US$5,000,000 or individuals with a net worth in excess of US$1,000,000 or annual income exceeding US$200,000 or US$300,000 jointly with their spouse.

The penny stock rules require a broker-dealer, prior to a transaction in a penny stock not otherwise exempt from the rules, to deliver a standardized risk disclosure document in a form prepared by the SEC which provides information about penny stocks and the nature and level of risks in the penny stock market. The broker-dealer also must provide the customer with current bid and offer quotations for the penny stock, the compensation of the broker-dealer and its salesperson in the transaction and monthly account statements showing the market value of each penny stock held in the customer's account. The bid and offer quotations, and the broker-dealer and salesperson compensation information, must be given to the customer orally or in writing prior to effecting the transaction and must be given to the customer in writing before or with the customer's confirmation.

In addition, the penny stock rules require that prior to a transaction in a penny stock not otherwise exempt from these rules, the broker-dealer must make a special written determination that the penny stock is a suitable investment for the purchaser and receive the purchaser's written agreement to the transaction. These disclosure requirements may have the effect of reducing the level of trading activity in the secondary market for the shares that are subject to these penny stock rules. Consequently, these penny stock rules may affect the ability of broker-dealers to trade our securities. We expect that the penny stock rules will discourage investor interest in and limit the marketability of our common shares.

In addition to the "penny stock" rules described above, The Financial Industry Regulatory Authority ("FINRA") has adopted rules that require that in recommending an investment to a customer, a broker-dealer must have reasonable grounds for believing that the investment is suitable for that customer. Prior to recommending speculative low priced securities to their non-institutional customers, broker-dealers must make reasonable efforts to obtain information about the customer's financial status, tax status, investment objectives and other information. Under interpretations of these rules, the FINRA believes that there is a high probability that speculative low priced securities will not be suitable for at least some customers. The FINRA requirements will make it more difficult for broker-dealers to recommend that their customers buy our common shares, which may limit your ability to buy and sell our shares and have an adverse effect on the market for our shares.

Risks Factors Relating to Our Business

Our future success is dependent upon our ability to locate, obtain and develop commercially viable oil and gas deposits. Our future success is dependent upon our ability to economically locate commercially viable oil and gas deposits. We may not be able to consistently identify viable prospects, and such prospects, if identified, may not be commercially exploitable. Our inability to consistently identify and exploit commercially viable hydrocarbon deposits would have a material and adverse effect on our business and financial position.

Exploratory drilling activities are subject to substantial risks. Our expected revenues and cash flows will be principally dependent upon the success of any drilling and production from prospects in which we participate. The success of such prospects will be determined by the economical location, development and production of commercial quantities of hydrocarbons. Exploratory drilling is subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected formation and drilling conditions, pressure or other irregularities in formations, blowouts, equipment failures or accidents, as well as weather conditions, compliance with governmental requirements or shortages or delays in the delivery of equipment. Our inability to successfully locate and drill wells that will economically produce commercial quantities of oil and gas could have a material adverse effect on our business and, financial position.

Our drilling and exploration plans will be subject to factors beyond our control. A prospect is a property that has been identified based on available geological and geophysical information that indicates the potential for hydrocarbons. Whether we ultimately drill a property may depend on a number of factors including funding; the receipt of additional seismic data or reprocessing of existing data; material changes in oil or gas prices; the costs and availability of drilling equipment; the success or failure of wells drilled in similar formations or which would use the same production facilities; changes in estimates of costs to drill or complete wells; our ability to attract industry partners to acquire a portion of our working interest to reduce exposure to drilling and completion costs; decisions of our joint working interest owners; and restrictions under provincial regulators.

Our operating results are subject to oil and natural gas price volatility. Our profitability, cash flow and future growth will be affected by changes in prevailing oil and gas prices. Oil and gas prices have been subject to wide fluctuations in recent years in response to changes in the supply and demand for oil and natural gas, market uncertainty, competition, regulatory developments and other factors which are beyond our control. It is impossible to predict future oil and natural gas price movements with any certainty. We do not engage in hedging activities. As a result, we may be more adversely affected by fluctuations in oil and gas prices than other industry participants that do engage in such activities. An extended or substantial decline in oil and gas prices would have a material adverse effect on our access to capital, and our financial position and results of operations.

Unforeseen title defects may result in a loss of entitlement to production and reserves. Although we conduct title reviews in accordance with industry practice prior to any purchase of resource assets, such reviews do not guarantee that an unforeseen defect in the chain on title will not arise and defeat our title to the purchased assets. If such a defect were to occur, our entitlement to the production from such purchased assets could be jeopardized.

Estimates of reserves and predictions of future events are subject to uncertainties. Certain statements included in this Annual Report contain estimates of our oil and gas reserves and the discounted future net revenues from those reserves, as prepared by independent petroleum engineers or us. There are numerous uncertainties inherent in such estimates including many factors beyond our control. The estimates are based on a number of assumptions including constant oil and gas prices, and assumptions regarding future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable oil and gas reserves. Such estimates are inherently imprecise indications of future net revenues, and actual results might vary substantially from the estimates based on these assumptions. Any significant variance in these assumptions could materially affect the estimated quantity and value of reserves. In addition, our reserves might be subject to revisions based upon future production, results of future exploration and development, prevailing oil and gas prices and other factors. Moreover, estimates of the economically recoverable oil and gas reserves, classifications of such reserves and estimates of future net cash flows prepared by independent engineers at different times may vary substantially. Information about reserves constitutes forward-looking statements.

The success of our business is dependent upon our ability to replace reserves. Our future success depends upon our ability to find, develop and acquire oil and gas reserves that are economically recoverable. As a result we must locate, acquire and develop new oil and gas reserves to replace those being depleted by production. Without successful funding for acquisitions and exploration and development activities, our reserves will decline. We may not be able to find and develop or acquire additional reserves at an acceptable cost.

Most of our competitors have substantially greater financial, technical, sales, marketing and other resources than we do. We engage in the exploration for and production of oil and gas, industries which are highly competitive. We compete directly and indirectly with oil and gas companies in our exploration for and development of desirable oil and gas properties. Many companies and individuals are engaged in the business of acquiring interests in and developing oil and gas properties in the United States and Canada, and the industry is not dominated by any single competitor or a small number of competitors. Many of such competitors have substantially greater financial, technical, sales, marketing and other resources, as well as greater historical market acceptance than we do. We will compete with numerous industry participants for the acquisition of land and rights to prospects, and for the equipment and labor required to operate and develop such prospects. Competition could materially and adversely affect our business, operating results and financial condition. Such competitive disadvantages could adversely affect our ability to participate in projects with favorable rates of return.

Shortages of supplies and equipment could delay our operations and result in higher operating and capital costs. Our ability to conduct operations in a timely and cost effective manner is subject to the availability of natural gas and crude oil field supplies, rigs, equipment and service crews. Although none are expected currently, any shortage of certain types of supplies and equipment could result in delays in our operations as well as in higher operating and capital costs.

Our business is subject to interruption from severe weather. Presently, our operations are conducted principally in the central region of Alberta, Canada and in Southwest Texas. The weather in these areas and other areas in which we may operate in the future can be extreme and can cause interruption or delays in our drilling and construction operations.

We are dependent on third-party pipelines and would experience a material adverse effect on our operations were our access to such pipelines be curtailed or the rates charged for use thereof materially increased. Substantially all our sales of natural gas production are effected through deliveries to local third-party gathering systems to processing plants. In addition, we rely on access to inter-provincial pipelines for the sale and distribution of substantially all of our gas. As a result, a curtailment of our sale of natural gas by pipelines or by third-party gathering systems, an impairment of our ability to transport natural gas on inter-provincial pipelines or a material increase in the rates charged to us for the transportation of natural gas by reason of a change in federal or provincial regulations or for any other reason, could have a material adverse effect upon us. In such event, we would have to obtain other transportation arrangements. We may not have economical transportation alternatives and it may not be feasible for us to construct pipelines. In the event such circumstances were to occur, our operating netbacks from the affected wells would be suspended until, and if, such circumstances could be resolved.

Our business is subject to operating hazards and uninsured risks. The oil and gas business involves a variety of operating risks, including fire, explosion, pipe failure, casing collapse, abnormally pressured formations, adverse weather conditions, governmental and political actions, premature reservoir declines, and environmental hazards such as oil spills, gas leaks and discharges of toxic gases. The occurrence of any of these events with respect to any property operated or owned (in whole or in part) by us could have a material adverse impact on us. Insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not insured or insured fully could have a material adverse effect on our financial condition.

Our business is subject to restoration, safety and environmental risk. Our present operations are primarily in western Canada and southwest Texas and certain laws and regulations exist that require companies engaged in petroleum activities to obtain necessary safety and environmental permits to operate. Such legislation may restrict or delay us from conducting operations in certain geographical areas. Further, such laws and regulations may impose liabilities on us for remedial and clean-up costs, or for personal injuries related to safety and environmental damages, such liabilities collectively referred to as “asset retirement obligations”. While our safety and environmental activities have been prudent in managing such risks, we may not always be successful in protecting us from the impact of all such risks.

The termination or expiration of any of our licenses and leases may have a material adverse effect on our results of operations. Our properties are held in the form of licenses and leases and working interests in licenses and leases. If we, or the holder of the license or lease, fail to meet the specific requirement of a license or lease, the license or lease may terminate or expire. We may not meet the obligations required to maintain each license or lease. The termination or expiration of our licenses or leases or the working interests relating to a license or lease may have a material adverse effect on our results of operations and business.

Compliance with new or modified environmental laws or regulations could have a materially adverse impact on us. We are subject to various Canadian and US laws and regulations relating to the environment. We believe that we are currently in compliance with such laws and regulations. However, such laws and regulations may change in the future in a manner which will increase the burden and cost of compliance. In addition, we could incur significant liability under such laws for damages, clean-up costs and penalties in the event of certain discharges into the environment. In addition, environmental laws and regulations may impose liability on us for personal injuries, clean-up costs, environmental damage and property damage as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for accidental environmental damages, but do not maintain insurance for the full potential liability that could be caused by such environmental damage. Accordingly, we may be subject to significant liability, or may be required to cease production in the event of the noted liabilities.

ITEM 4 INFORMATION ON THE COMPANY

We are amalgamated under the laws of the Province of Ontario. Our primary activities are investment in, exploration and development and production of oil and gas.

We hold a 0.5% non-convertible gross overriding royalty in a natural gas well located in the Haynes area in the Province of Alberta, Canada.

We hold a 5.1975% working interest held in trust through a joint venture partner in a natural gas unit located in the Botha area in the Province of Alberta, Canada.

Through Dyami Energy LLC we hold a 75% working interest before payout which reduces to a 61.50% working interest after payout of $12,500,000 of production revenue in the Matthews lease. Directly, we hold a 10% working interest before payout which reduces to a 7.50% working interest after payout of $15,000,000 of production revenue in the Matthews lease. We have entered into a farm out agreement for a portion of our working interests from the surface to the base of the San Miguel formation in the Matthews Lease. The Matthews lease comprises approximately 2,629 gross acres of land in Zavala County, Texas. Through Dyami Energy LLC, we hold a 100% working interest in the Murphy Lease comprising approximately 2,637 acres of land in Zavala County, Texas subject to a 10% carried interest on the drilling costs from surface to base of the Austin Chalk formation, and a 3% carried interest on the drilling costs from the top of the Eagle Ford shale formation to basement on the first well drilled into a serpentine plug and for the first well drilled into a second serpentine plug, if discovered.

Our registered office and management office is located at 1 King Street West, Suite 1505, Toronto, Ontario, M5H 1A1, Telephone (416) 364-4039, Facsimile (416) 364-8244. Our books and financial records are located in the registered office and management office. Our Canadian public filings can be accessed and viewed via the System for Electronic Data Analysis and Retrieval ("SEDAR") at www.sedar.com. Readers can also access and view our Canadian public insider trading reports via the System for Electronic Disclosure by Insiders at www.sedi.ca. Our Registrar and Transfer Agent is Equity Financial Trust Company located at Suite 400, 200 University Avenue, Toronto, Ontario, M5H 4H1. Our U.S. public filings are available at the public reference room of the U.S. Securities and Exchange Commission ("SEC") located at 100 F Street, N.E., Room 1580, Washington, DC 20549 and at the website maintained by the SEC at www.sec.gov.

A. HISTORY AND DEVELOPMENT OF THE COMPANY

We were incorporated in Ontario, Canada on September 22, 1978, under the Business Corporations Act (*Ontario*), under the name Bonanza Red Lake Explorations Inc. ("Bonanza Red Lake"). By prospectus dated November 20, 1978 and a further amendment to the Prospectus dated January 10, 1979 we became a reporting issuer in the Province of Ontario and raised $250,000 to acquire interests in and to explore and develop certain mineral lands located near the Town of Red Lake, Ontario, Canada. In 1987, we optioned our mineral lands in Red Lake, Ontario to Pure Gold Resources Inc., who expended sufficient funds during 1988 and 1989 to earn an 85% interest in our eight patented mineral claims, and then discontinued its exploration program on the property. Bonanza Red Lake had subsequently written the carrying amount of these mineral claims down to $1.

On March 29, 2000, Bonanza Red Lake entered into a Share Exchange Agreement with 1406768 Ontario Inc. ("1406768 Ontario"). 1406768 Ontario is a company incorporated under the laws of the Province of Ontario by articles of incorporation dated effective March 13, 2000. The purpose of the transaction was to allow Bonanza Red Lake to acquire a company, 1406768 Ontario, which resulted in our owning part of an operating business. At an Annual and Special Meeting of shareholders held on May 10, 2000 we received shareholder approval for the acquisition of 1406768 Ontario; the consolidation of Bonanza Red Lake's issued and outstanding common shares on a one new common share for every three old common shares basis; a name change from Bonanza Red Lake to Eugenic Corp; a new stock option plan (the "Plan") authorizing 1,275,000 common shares to be set aside for issuance under the Plan; and authorizing the directors to determine or vary the number of directors of the Company from time to time which pursuant to our Articles provide for a minimum of three and a maximum of ten.

By Articles of Amendment dated August 15, 2000, Bonanza Red Lake consolidated its issued and outstanding common shares on a one new common share for every three old common shares basis and changed the name of the company to Eugenic Corp.

We completed the acquisition of 1406768 Ontario on October 12, 2000 and acquired all of the issued and outstanding shares of 1406768 Ontario for $290,000. The purchase price was satisfied by our issuance of 5,800,000 company units at $0.05 per unit. Each unit consisted of one common share and one common share purchase warrant entitling the holder to purchase one common share of ours at an exercise price of $0.25 per common share until October 12, 2003. As a result of this transaction, the original shareholders of 1406768 Ontario owned 90.7% of our issued shares. The acquisition resulted in a change in business and an introduction of new management for us. The acquisition was accounted for as a reverse take-over of us by 1406768 Ontario. Our net assets acquired at fair value as at October 12, 2000 resulted in a deficiency of assets over liabilities in the amount of $123,170 which was charged to share capital. All of the 5,800,000 outstanding warrants expired on October 12, 2003.

As part of an initiative to create cash flow, we commenced oil and gas operations effective August 31, 2001 and acquired a 25% working interest in one section of land (640 gross acres) in the Windfall Area of Alberta, Canada for a purchase price of $75,000. On June 25, 2003 we disposed of this property for net proceeds of $85,000.

On September 10, 2001, we entered into a Participation Agreement to acquire a 30% interest in one section of land (640 gross acres) in the St Anne area of Alberta, Canada by paying 40% of the costs to acquire approximately 7.1 kilometers of proprietary 2D seismic data. After review of the seismic data, it was determined that the joint partners would not undertake to drill a test well. Accordingly, the costs associated with acquiring this prospect were written off during fiscal 2003 - $4,806 and in fiscal 2002 - $22,781.

We entered into an Agreement dated February 28, 2002 to participate in drilling two test wells by paying 10% of the costs to drill to earn a 6% working interest before payout and a 3.6% working interest after payout. The first test well in the Haynes area of Alberta, Canada was drilled and proved to contain uneconomic hydrocarbons and was subsequently abandoned and costs of $38,855 were written off in 2002. On August 28, 2003 the joint partners farmed out their interest in the Haynes prospect for a 10% non-convertible overriding royalty (“NCOR”). The farmee drilled a test well and placed the well on production commencing December 2003. Our share of this NCOR is 0.5%. The second test well in the Mikwan area of Alberta, Canada was drilled and initially placed on production from the Glauconite formation and later shut in during 2003. The Glauconite formation was subsequently abandoned and the Belly River formation was completed and placed on production in January 2004.

Effective August 9, 2002, we entered into an agreement with Wolfden Resources Inc. (“Wolfden”) and sold our 15% interest in 8 patented mining claims located in Dome Township, Red Lake, Ontario (the “Mining Claims”) for consideration of $5,000 plus we retained a 0.3% net smelter return royalty of the net proceeds realized from the sale of recovered minerals. Wolfden also holds a right of first refusal to purchase our 0.3% net smelter return royalty. Pursuant to an arrangement dated effective August 18, 2006, Wolfden transferred certain assets including its interests in and to the Mining Claims to Premier Gold Mines Limited (“Premier”).

Effective October 28, 2005, we surrendered our 6% working interest in a gas well slated for abandonment and related expiring leases in the Mikwan area of Alberta. In exchange for the surrender of interests, we were released of our abandonment and site reclamation obligations.

On April 14, 2008, we completed a non-brokered private placement of a total of 2,575,000 units (each a "Unit") at a purchase price of $0.10 per Unit for gross proceeds of $257,500 (the "Offering"). Each Unit was comprised of one common share and one purchase warrant (each a "Warrant"). Each Warrant is exercisable until April 14, 2011 to purchase one additional share of our common stock at a purchase price of $0.20 per share.

On April 14, 2008, we also entered into an agreement (the "Debt Settlement Agreement") with our then President, Secretary and Director, Sandra J. Hall, to convert debt in the amount of $50,000 through the issuance of a total of 500,000 shares at an attributed value of $0.10 per Share. In connection with the conversion, Ms. Hall also agreed to forgive $38,000 of the debt owing to her by us.

In addition, on April 14, 2008, we also completed similar debt settlement arrangements with two other arm's length parties, in an effort to reduce the debt that we have reflected on our financial statements. In the aggregate, we entered into agreements to convert $100,000 of debt, through the issuance of a total of 1,000,000 shares at an attributed value of $0.10 per share.

On February 5, 2009, we completed a non-brokered private placement of 2,600,000 units (each a “Unit”) at a purchase price of $0.05 per Unit for gross proceeds of $130,000. Each Unit was comprised of one common share (each a “Unit Share”) and one purchase warrant (each a “Warrant”). Each Warrant is exercisable until February 5, 2014 to purchase one additional share of our common stock (each a “Warrant Share”) at a purchase price of $0.07 per share. 1407271 Ontario Inc. purchased 1,600,000 units. 1407271 Ontario Inc. is owned 100% by our former President, Ms. Sandra Hall. Ms. Hall is also the sole director and officer of 1407271.

On February 25, 2009, we completed a non-brokered private placement of 1,000,256 units (each a “Unit”) at a purchase price of $0.05 per Unit for gross proceeds of approximately $50,013. Each Unit was comprised of one common share (each a “Unit Share”) and one purchase warrant (each a “Warrant”). Each Warrant is exercisable until February 25, 2014 to purchase one additional share of our common stock (each a “Warrant Share”) at a purchase price of $0.07 per share. Sandra Hall, our former president and former director, and Milton Klyman, a director, purchased 600,000 Units and 50,000 Units, respectively.

On February 27, 2009, we purchased all of the issued and outstanding shares issued in the capital stock of 1354166 Alberta Ltd. ("1354166 Alberta"), a company incorporated on October 3, 2007 in the Province of Alberta Canada (the "Transaction") under the Business Corporations Act (Alberta). In connection therewith, we issued to the shareholders of 1354166 an aggregate of 8,910,564 units (each a "Unit") at $0.05 per unit or an aggregate of $445,528 and following the closing repaid $118,000 of shareholder loans in 1354166 by cash payment. . Each unit is comprised of one share of our common stock (each a "Share") and one purchase warrant (each a "Warrant"). Each Warrant is exercisable until February 27, 2014 to purchase one additional share of our common stock at a purchase price of $0.07 per share. 1354166 is a private company that has a 5.1975% working interest held in trust through a joint venture partner in a natural gas unit located in the Botha area of Alberta, Canada.

On February 27, 2009, we entered into an agreement with a non-related party, to convert debt in the amount of $62,500 through the issuance of a total of 1,250,000 units at an attributed value of $0.05 per unit (the "Debt Settlement"). Each Unit was comprised of one common share (each a "Unit Share") and one purchase warrant (each a "Warrant"). Each Warrant is exercisable until February 27, 2014 to purchase one additional share of our common stock (each a "Warrant Share") at a purchase price of $0.07 per share.

By Articles of Amendment dated November 12, 2009, 1406768 Ontario changed its name to Eagleford Energy Inc. By Articles of Amalgamation dated November 30, 2009 we amalgamated with Eagleford Energy Inc. and upon the amalgamation the amalgamated entity's name became Eagleford Energy Inc.

Effective June 10, 2010, we retained Gar Wood Securities, LLC ("Gar Wood") to act as Investment Banker/Financial Advisor to the Company for a period of two years. Under the terms of the Gar Wood engagement, we agreed to pay a fee of 6% of the gross proceeds raised and issue 1,500,000 common share purchase warrants (the "Warrants") as follows:

1,000,000 Warrants exercisable at US$1.00 to purchase 1,000,000 common shares expiring on December 10, 2011 and issuable in three equal tranches on June 10, 2010, December 10, 2010 and June 10, 2011; and

500,000 Warrants exercisable at US$1.50 to purchase 500,000 common shares expiring on June 10, 2012 and issuable in three equal tranches on June 10, 2010, December 10, 2010 and June 10, 2011.

On November 5, 2010 we terminated the agreement with Gar Wood dated June 10, 2010. As a result 36,430 warrants were cancelled out of the 333,333 warrants issued exercisable at $1.00 expiring December 10, 2011 and 18,215 warrants were cancelled out of the 166,667 warrants issued exercisable at $1.50 expiring June 10, 2012. On December 10, 2011 296,903 warrants exercisable at US $1.00 expired.

During the fiscal year ended August 31, 2010, 1,100,000 of our common share purchase warrants were exercised at $0.07 expiring February 5, 2014 for proceeds of $77,000 and 1,000,000 of our common share purchase warrants were exercised at $0.07 expiring February 27, 2014 for proceeds of $70,000.

On August 31, 2010 we acquired a 10% working interest before payout and a 7.5% working interest after payout of production revenue of $15 million in the Matthews lease comprising approximately 2,629 gross acres of land in Zavala County, Texas (the "Lease Interest"). As consideration for the Lease Interest we paid on closing $212,780 (US$200,000), satisfied by US$25,000 in cash and $186,183 (US$175,000) satisfied by the issuance of a 5% secured promissory note.US$100,000 of principal together with accrued interest is due and payable on February 28, 2011 and US$75,000 of principal together with accrued interest is due and payable on August 31, 2011. The note was secured by the Lease Interest.

On August 31, 2010, we acquired 100% of the issued and outstanding membership interests of Dyami Energy LLC, a Texas limited liability corporation for consideration of $4,218,812. (US$3,965,422) satisfied by (i) the issuance of 3,418,467 units of the Company. Each unit is comprised of one common share and one-half a purchase warrant. Each full warrant is exercisable into one additional common share at US$1.00 per share on or before August 31, 2014 (the "Units') and (ii) the assumption of $1,021,344 (US$960,000) of Dyami Energy debt by way of a secured promissory note payable to Benchmark Enterprises LLC ("Benchmark"). The note bears interest at 6% per annum, is secured by Dyami's interest in the Matthews and Murphy leases and was payable on December 31, 2011 or upon the Company closing a financing or series of financings in excess of US$4,500,000. The due date of the note has been extended until June 30, 2012 with an interest rate of 10% per annum. On January 3, 2012 we issued 515,406 common shares to shares Benchmark as full settlement of interest due at December 31, 2011 in the amount of $103,028.

Dyami Energy holds a 75% working interest before payout and a 61.50% working interest after payout of production revenue of $12.5 million in the Matthews Lease comprising approximately 2,629 gross acres of land in Zavala County, Texas and a 100% working interest in a mineral lease comprising approximately 2,637 acres of land in Zavala County, Texas (the "Murphy Lease") subject to a 10% carried interest on the drilling costs from surface to base of the Austin Chalk formation, and a 3% carried interest on the drilling costs from the top of the Eagle Ford shale formation to basement on the first well drilled into a serpentine plug and for the first well drilled into a second serpentine plug, if discovered (collectively the "Leases").

The Members of Dyami entered into lock up agreements on closing and placed 50% of the Units in escrow (1,709,234 common shares and 854,617 purchase warrants) until such time that we receive a National Instrument 51-101 compliant report from an independent engineering firm indicating at least 100,000 boe of proven reserves on either the Murphy Lease or any formation below the San Miguel on the Matthews Lease (the "Report"). In the event the Report is not received by Dyami Energy within two years of the closing date of the acquisition, the escrow units are to be returned to us for cancellation.

In connection with the Dyami Energy acquisition, we entered into a one year employment agreement with Eric Johnson and reserved 850,000 common share purchase warrants, exercisable on an earn-out basis, for the purchase of 850,000 common shares of our stock at a price of US$1.00 per share during a period of five years from the date of issuance. On April 13, 2011 the employment agreement was terminated.

During the fiscal year ended August 31, 2010 we spent $10,046 on exploration expenditures related to the Matthews Lease.During the fiscal year ended August 31, 2011, the Company drilled four wells on its leases located in Zavala County, Texas USA. The wells have been extensively logged and cored in various formations. The Company is reviewing its data to determine completion programs.

On March 31, 2011 the Company entered into a Farmout Agreement (the "Farmout") from surface to the base of the San Miguel formation (the "San Miguel") on the Matthews Lease located in Zavala County, Texas. Under the Farmout, the farmee may spend up to US$1,050,000 on exploration and development of the San Miguel to earn a maximum of 42.50% working interest (31.875% net revenue interest). Under the terms of the Farmout, the farmee may earn an initial 25% of the Company's working interest in the San Miguel by paying 100% of the costs to drill, complete, equip and perform an injection operation on a test well to a depth of approximately 3,500 feet (the "Initial Test Well"). After the performance of the Initial Test Well, the farmee may increase its working interest to 50% of the Company's working interest by spending the entire $1,050,000 on additional operations on the San Miguel in a good faith effort to produce hydrocarbons. During the year ended August 31, 2011, the Company received US$647,536 from the farmee for costs related to the drilling, completion and injection operation of the Matthews/Dyami #3 well. As at August 31, 2011 and the date of this Annual Report the Company had not assigned any interest to the farmee in the San Miguel formation.

On July 30, 2011 we commenced drilling our 100% working interest Murphy/Dyami #2 well. The well was drilled to a vertical depth of 4,415 feet into the Eagle Ford shale formation.

During the fiscal year ended August 31, 2011 we spent $3,158,688 on exploration expenditures related to the Matthews and Murphy Leases.

During the year ended August 31, 2011, 500,000 of our common share purchase warrants were exercised at $0.07 expiring February 5, 2014 for proceeds of $35,000; 625,247 of our common share purchase warrants were exercised at $0.07 expiring February 27, 2014 for proceeds of $44,475; and 2,575,000 of our common share purchase warrants were exercised at $0.20 expiring April 14, 2011 for proceeds of $515,000.

During the year ended August 31, 2011 we received $2,878,736 and issued demand promissory notes bearing interest at 10% per annum. Interest is payable annually on the anniversary date of the notes.

During the year ended August 31, 2011 we paid $98,440 of secured notes and $110,000 loan payable.

On September 1, 2011 we repaid to Source, the secured promissory note in full in the amount of US$75,000 together with accrued interest of US$6,250.

Subsequent to our year ended August 31, 2011, we commenced drilling our Matthews/Dyami #2H well located in Zavala County, Texas.

Subsequent to our year ended August 31, 2011 and to the date of this Annual Report, we issued 639,298 common shares to promissory note holders as full settlement of interest due in the amount of $183,099.

Subsequent to our year ended August 31, 2011 and to the date of this annual report we received $221,845 and US$175,000 and issued promissory notes to seven shareholders of the Company. The notes are due on demand and bear interest at 10% per annum. Interest is payable annually on the anniversary date of the note.

Subsequent to our year ended August 31, 2011, we converted debt in the aggregate amount of CDN$300,000 through the issuance of a total of 3,000,000 units in the capital of the Company at an attributed value of $0.10 per Unit. Each unit is comprised of one (1) common share and one (1) purchase warrant, where each whole warrant is exercisable until January 24, 2015 to purchase one (1) additional common share of our stock at a purchase price of $0.10 per share.

We intend to apply additional capital to further enhance our property interests. As part of our oil and gas development program, management of the Company anticipates further expenditures to expand its existing portfolio of proved reserves. Amounts expended on future exploration and development are dependent on the nature of future opportunities evaluated by us. These expenditures could be funded through cash held by the Company or through cash flow from operations. Any expenditure which exceeds available cash will be required to be funded by additional share capital or debt issued by us, or by other means. Our long-term profitability will depend upon our ability to successfully implement our business plan.

Our past primary source of liquidity and capital resources has been loans and advances, cash flow from oil and gas operations and proceeds from the sale of marketable securities and from the issuance of common shares.

Our registered office and principal place of business in Ontario is located at 1 King Street West, Suite 1505, Toronto, Ontario M5H 1A1. Our telephone number at that address is (416) 364-4039.

B. BUSINESS OVERVIEW

Directly and through our wholly owned subsidiaries 1354166 Alberta and Dyami Energy we are primarily engaged in the development, acquisition and production of oil and gas interests located in Alberta, Canada and Texas, USA. Our operations consist of a 0.5% NCOR in a natural gas well located in Haynes, Alberta, Canada a 5.1975% working interest in a natural gas unit located in Alberta, Canada, an 85% working interest before payout (69% working interest after payout) in Matthews lease comprising 2,629 gross acres of land in Zavala County, Texas. We have entered into a farm out agreement for a portion of our working interests from the surface to the base of the San Miguel formation in the Matthews Lease. As of the date of this Annual Report, we have not assigned any working interest in the San Miguel formation. In addition, we hold a 100% working interest in the Murphy lease comprising approximately 2,637 acres of land in Zavala County, Texas subject to a 10% carried interest on the drilling costs from surface to base of the Austin Chalk formation, and a 3% carried interest on the drilling costs from the top of the Eagle Ford shale formation to basement on the first well drilled into a serpentine plug and for the first well drilled into a second serpentine plug, if discovered.

We have a 0.3% Net Smelter Return Royalty on 8 patented mining claims located in Red Lake, Ontario, Canada.

For the three fiscal years ending August 31, 2011, 2010 and 2009 the total gross revenue derived from the sale of our natural gas interests in Canada was as follows:

	Total
August 31, 2011	$ 71,786
August 31, 2010	$105,375
August 31, 2009	$ 56,199

We sell our natural gas production to integrated oil and gas companies and marketing agencies. Sales prices are generally set at market prices available in Canada or the United States.

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw make the ground unstable and municipalities and provincial transportation departments enforce road bans that may restrict the level of activity. Seasonal factors and unexpected weather patterns may lead to declines in production activity and increased consumer demand or changes in supply during certain months of the year may influence the commodity prices.

There is an existing and available market for the oil and gas produced from the properties. However, the prices obtained for production are subject to market fluctuations, which are affected by many factors, including supply and demand. Numerous factors beyond our control, which could affect pricing include:

- the level of consumer product demand;
- weather conditions;
- the foreign supply of oil and gas;
- the price of foreign imports;
- volatility in market prices for oil and natural gas;
- ability to raise financing;
- reliance on third party operators;
- ability to find or produce commercial quantities of oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- dilution of interests in oil and natural gas properties;
- general business and economic conditions;
- the ability to attract and retain skilled staff;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, financings, acquisitions of reserves, undeveloped lands and skilled personnel; and
- governmental regulation and environmental legislation.

We caution that the foregoing list of important factors is not exhaustive. Investors and others who base themselves on our forward-looking statements should carefully consider the above factors as well as the uncertainties they represent and the risk they entail. We also caution readers not to place undue reliance on these forward-looking statements. Moreover, the forward-looking statements may not be suitable for establishing strategic priorities and objectives, future strategies or actions, financial objectives and projections other than those mentioned above.
We do not have a reliance on raw materials, as we operate in an extractive industry.

We do not have a reliance on any significant patents or licenses.

The oil and gas business is highly competitive in every phase. Many of our competitors have greater financial and technical resources, and have established multi-national operations, secured land rights and licenses, which we may not have. As a result, we may be prevented from participating in drilling and acquisition programs (See, Item 3.D Key Information - Risk Factors).

Governmental Regulation/Environmental Issues
Our oil and gas operations are subject to various United States and Canadian governmental regulations including those imposed by the Texas Railroad Commission and Alberta Energy Resources Conversation Board and Alberta Utilities Commission. Matters subject to regulation include discharge permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells, and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas. The production, handling, storage, transportation and disposal of oil and gas, by-products thereof, and other substances and materials produced or used in connection with oil and gas operations are also subject to regulation under federal, state, provincial and local laws and regulations relating primarily to the protection of human health and the environment. To date, expenditures related to complying with these laws, and for remediation of existing environmental contamination, have not been significant in relation to the results of operations of our company. The requirements imposed by such laws and regulations are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. These regulations may adversely affect our operations and cost of doing business. It is likely that these laws and regulations will become more stringent in the future (See, Item 3.D Key Information - Risk Factors).

C. ORGANIZATIONAL STRUCTURE

We have two wholly owned subsidiaries. 1354166 Alberta Ltd. is a company incorporated under the Business Corporations Act (*Alberta*) and Dyami Energy LLC is a Texas Limited Liability company.

D. PROPERTY, PLANTS AND EQUIPMENT

Our executive offices consist of approximately 140 square feet of office space and are rented at $500 per month on a month to month basis. The address of our executive offices is 1 King Street West, Suite 1505, Toronto, Ontario Canada.

Canada
We hold directly a 0.5% NCOR in a natural gas well located in Haynes, Alberta, Canada.
We hold through our wholly owned subsidiary 1354166 Alberta a 5.1975% working interest in a natural gas unit located in Botha, Alberta, Canada.

We have a 0.3% Net Smelter Return Royalty on eight patented mining claims located in Red Lake, Ontario, Canada.

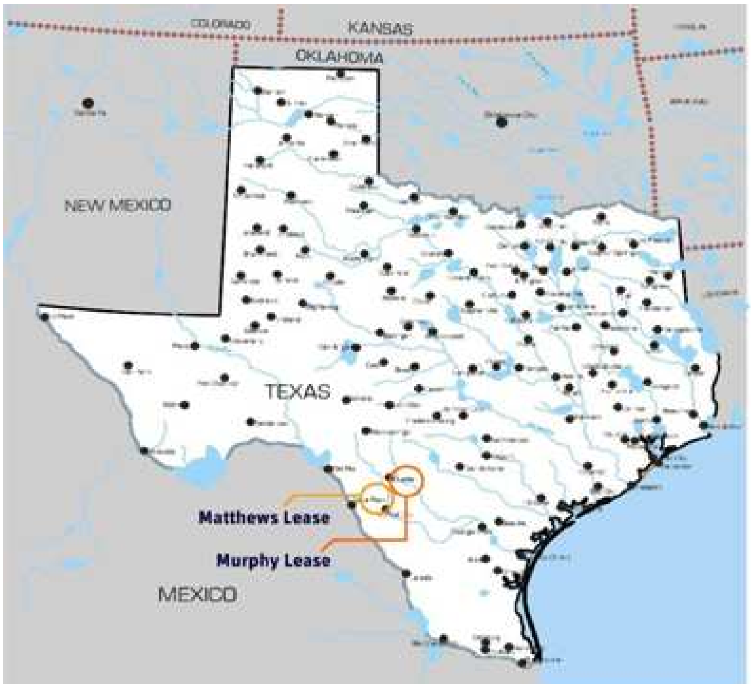
United States
We hold through our wholly owned subsidiary Dyami Energy a 75% working interest before payout and a 61.5% working interest after payout of $12,500,000 of production in Matthews lease comprising approximately 2,629 gross acres of land in Zavala County, Texas.
We hold directly a 10% working interest before payout and a 7.5% working interest after payout of $15,000,000 of production in Matthews lease comprising approximately 2,629 gross acres of land in Zavala County, Texas.

We have entered into a farm out agreement for a portion of our working interests from the surface to the base of the San Miguel formation in the Matthews Lease. To date we have not assigned any interest in the San Miguel formation.

We hold through our wholly owned subsidiary Dyami Energy, a 100% working interest in the Murphy lease comprising approximately 2,637 acres of land in Zavala County, Texas subject to a 10% carried interest on the drilling costs from surface to base of the Austin Chalk formation, and a 3% carried interest on the drilling costs from the top of the Eagle Ford shale formation to basement on the first well drilled into a serpentine plug and for the first well drilled into a second serpentine plug, if discovered. The Matthews and Murphy Leases are subject to royalties payable of 25%.

Our Matthews Lease is situated in Zavala County, Texas and is part of the Maverick Basin of Southwest Texas and downdip from the United States Geological Studies north boundary of the Smackover-Austin-Eagle Ford total petroleum system.

The map below indicates the location of our Matthews Lease and Murphy Lease located in Zavala County, Texas.



The table below is a glossary of terms and abbreviations that may be used in this Item.

GLOSSARY OF TERMS

Natural Gas	Mcf	1,000 cubic feet
	MMcf	1,000,000 cubic feet
	Mcf/d	1,000 cubic feet per day
Oil and Natural Gas Liquids	Bbl	Barrel
	Mbbls	1,000 barrels
	Blpd	Barrels of liquid per day
	Boe	Barrel of oil equivalent (1)
	Bpd	Barrels per day
	Boepd	Barrels of oil equivalent per day
	Bopd	Barrels of oil per day
	NGLs	Natural gas liquids

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

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.317
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.289
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres (Alberta)	Hectares	0.405
Hectares (Alberta)	Acres	2.471

Reserve Information: The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economics 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 changes. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. These factors and assumptions include among others (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates, (iii) production decline rates, (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production, (vii) effects of government regulation; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required for changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserve estimates can arise from changes in year–end prices, reservoir performance and geological conditions or production. These revisions can be either positive or negative (See Item 3.D. Key Information – Risk Factors).

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.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The qualitative certainty levels contained in the definitions in proved, probable and possible reserves are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

a. There is a 90% probability that at least the estimated proved reserves will be recovered.
b. There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.
c. There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

The crude oil and natural gas industry commonly applies a conversion factor to production and estimated proved reserve volumes of natural gas in order to determine an “all commodity equivalency” referred to as barrels of oil equivalent (“boe”). The conversion factor we have applied in this Report is the current convention used by many oil and gas companies, where six thousand cubic feet (“mcf”) is equal to one barrel (“bbl”). A boe is based on an energy equivalency conversion method primarily applicable at the burner tip. It may not represent equivalency at the wellhead and may be misleading if used in isolation.

Internal Controls for Reserves Reporting : A significant component of our internal controls in our reserve estimation effort is our practice of using an independent third-party reserve engineering firm to prepare 100% of our year-end proved and probable reserves. The qualifications of this firm are discussed below under “Independence and Qualifications of Reserve Preparer.” The Board of Directors of the Company has reviewed the reserves estimates and procedures prior to acceptance of the report. The Board of Directors has sufficient technical training and experience to review and approve the report.

Our director Mr. McNeil, chair of our petroleum and natural gas committee maintains oversight and compliance responsibility for the internal reserve estimate process and provides appropriate data to our independent third party reserve engineers to estimate our year-end reserves. Mr. McNeil is a self-employed oil and gas consultant and has been a geophysicist since 1972. Mr. McNeil is a member of the Association of Professional, Engineers, Geologists and Geophysicists of Alberta, Society of Exploration Geophysicists, Canadian Society of Exploration Geophysicists, American Association of Petroleum Geologists and the Canadian Society of Petroleum Geologists.

Independence and Qualifications of Reserve Preparer: We engaged Sproule Associates Limited ("Sproule"), third-party reserve engineers, to prepare our reserves as of the effective date August 31, 2011, 2010 and 2009 completed on October 17, 2011, November 30, 2010 and November 30, 2009 respectively, in accordance with reserves definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (COGE), the Canadian Securities Administrators National Instrument 51-101 (NI 51-101) using Forecast Pricing Assumptions and, for the Securities and Exchange Commission, using Constant Pricing Assumptions. The technical person responsible for our reserve estimates at Sproule meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth by The Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA). Sproule is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists; they do not own any interest in our properties and are not employed on a contingent fee basis.

Year-end reserves quantities for the years ended August 31, 2011, 2010 and 2009 shown in the following Constant Prices and Cost tables were calculated using the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12 month period prior to the end of the reporting period.

Appropriate adjustments have been made to account for quality and transportation, to the constant natural gas prices, and to the constant natural gas by-products prices to reflect historical prices received for each area. It should not be assumed that the discounted net present value estimated by Sproule represents the fair market value of the reserves. Where the present value is based on constant price and cost assumptions, there is no assurance that such price and cost assumptions will be attained and variances could be material.

At August 31, 2011, our developed properties include a 5.1975% working interest in a natural gas unit located in the Botha area Northwest, Alberta near the town of Manning, Canada held through our wholly owned subsidiary 1354166 Alberta. The unit is governed by a Pooling Agreement dated December 1, 1991 (covering Natural Gas in the Debolt formation) which contains a Right of First Refusal provision. Under a participation agreement dated October 15, 2003, 1354166 Alberta's working interest is held in trust by a joint interest partner.

The table below sets out in CDN dollars the constant prices and the exchange rate used at August 31, 2011, 2010 and 2009. As of August 31, 2011 all of our reserves were located in Alberta, Canada.

August 31, 2011	Natural Gas Alberta AECO-C	$3.77/Mcf
	Exchange Rate:	1.01$ US/$ CDN
August 31, 2010	Natural Gas Alberta AECO-C	4.07 $/Mcf
	Exchange Rate:	0.956 $ US/$ CDN
August 31, 2009	Natural Gas Alberta AECO-C	2.14 $/Mcf
	Exchange Rate:	0.9132 $ US/$ CDN

Proved and Probable Reserve Quantity Estimates: The following table reflects estimates of our proved and probable developed reserves as at August 31, 2011, 2010, and 2009 as reported by Sproule stated in CDN dollars. All of our gas reserves are located in Canada. The following table represents our gross and net interest in reserves (after crown royalties, freehold royalties and overriding royalties and interests owned by others). Numbers may not add due to rounding.

Summary of Oil and Gas Reserves
Constant Prices and Costs
Remaining Reserves

August 31, 2011	**Natural Gas (non-associated & associated)**	
Reserves Category	**Gross (MMcf)**	**Net (MMcf)**
Proved Developed Producing	153	128
Probable Developed Producing	42	34
Total Proved Plus Probable	**195**	**161**
August 31, 2010		
Reserves Category		
Proved Developed Producing	183	152
Probable Developed Producing	58	48
Total Proved Plus Probable	**241**	**200**
August 31, 2009		
Reserves Category		
Proved Developed Producing	35	29
Probable Developed Producing	12	10
Total Proved Plus Probable	**47**	**39**

The following table represents the summary of our Net Revenue based on Constant Prices and costs before income taxes. Numbers may not add due to rounding.

Summary of Net Revenue
Constant Prices and Costs
(Undiscounted)

Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Well Abandonment and Reclamation Costs (M$)**	**Net Revenue (M$)**
August 31, 2011					
Proved Developed Producing	599	77	414	4	103
Probable	165	26	116	-	23
Total Proved Plus Probable	**764**	**104**	**530**	**4**	**126**
August 31, 2010					
Proved Developed Producing	698	102	418	5	173
Probable	223	32	135	-	56
Total Proved Plus Probable	**921**	**134**	**554**	**5**	**229**
August 31, 2009					
Proved Developed Producing	Nil	Nil	Nil	Nil	Nil
Probable	Nil	Nil	Nil	Nil	Nil
Total Proved Plus Probable	Nil	Nil	Nil	Nil	Nil

The following table represents the summary of our net present value of Future Net Revenue based on Constant Prices and costs before income taxes and discounted as follows. Numbers may not add due to rounding.

Summary of Net Present Values of
Future Net Revenue
Constant Prices and Costs

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/Year)				
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
August 31, 2011					
Proved Developed Producing	103	86	73	63	56
Probable	23	15	11	8	7
Total Proved Plus Probable	**126**	**101**	**84**	**72**	**63**
August 31, 2010					
Proved Developed Producing	173	135	110	93	81
Probable	56	32	20	13	9
Total Proved Plus Probable	**229**	**167**	**130**	**106**	**90**
August 31, 2009					
Proved Developed Producing	Nil	Nil	Nil	Nil	Nil
Probable	Nil	Nil	Nil	Nil	Nil
Total Proved Plus Probable	Nil	Nil	Nil	Nil	Nil

Production Volume: The following table sets forth the net quantities of natural gas produced during the fiscal years ended August 31, 2011, 2010 and 2009.

August 31,	**2011**	**2010**	**2009**
Natural Gas (Mcf)	19,500	24,950	16,412

Historical Production: The following table sets out our net share of production, average sales prices, average royalties, production costs and average net back per unit of production for the fiscal years ended August 31, 2011, 2010 and 2009.

	For the Years Ended		
Historical Production	**August 31, 2011**	**August 31, 2010**	**August 31, 2009**
Natural Gas – Mcf/d	53	68	451
Natural Gas Prices- $/Mcf	$ 3.68	$ 4.42	$ 3.42
Royalty Costs - $/Mcf	0.76	0.98	0.63
Production Costs - $/Mcf	2.68	2.62	3.281
Net Back - $/Mcf	$ 0.24	$ 0.62	$ (0.49)

Producing Wells: The following table sets out the number of gross and net producing oil and natural gas wells and the number of gross and net non-producing oil and natural gas wells that we have an interest in by location at August 31, 2011, 2010 and 2009. A gross well is a well in which we own an interest. A net well represents the fractional interest we own in gross wells.

August 31	**2011**		**2010**		**2009**	
Alberta, Canada	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Natural Gas Wells-Producing	3.0	.15525	3.0	.15525	3.0	.15525
Natural Gas Wells-Non Producing	6.0	.3105	6.0	.3105	6.0	.3105
Texas, USA						
Oil Wells – Non Producing	4.0	3.80	Nil	Nil	Nil	Nil

Acreage: The following table sets forth the developed and undeveloped acreage of the projects in which the Company holds an interest, on a gross and a net basis as of August 31, 2011, 2010 and 2009. The developed acreage is stated on the basis of spacing units designated by provincial authorities and typically on the basis of 160 acre spacing unit for oil production and 640 acre spacing unit for gas production in Alberta. Our developed acreage is located in Alberta, Canada. Our undeveloped acreage is located in Zavala County, Texas.

August 31,	**2011**		**2010**		**2009**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Developed Acreage, Canada	8,320	432	8,320	432	8,320	432
Undeveloped Acreage, USA	5,266	4,793	5,266	4,872	Nil	Nil

Additional Information Concerning Abandonment and Reclamation Costs: We base our estimates for costs of abandonment and reclamation of surface leases and wells on previous experience with similar well site locations and terrain, estimates obtained from area operators and various regulatory abandonment guidelines and requirements.

We believe that our range of estimates for abandonment and reclamation costs are reasonable and applicable to our wells. Our independent qualified reserves evaluator has also estimated similar costs in deriving our estimate of future net revenue. Ultimately all wells in which hawse have an interest will require abandonment and reclamation. The total estimated undiscounted cash flows adjusted for inflation required to settle our asset retirement obligations for 4.27 net wells for the fiscal year ended August 31, 2011 is approximately $102,974. Using a credit adjusted risk free rate of 7% and an inflation rate of 3.9% this amount is approximately $50,208. We estimate that the settlement of these obligations will occur between 2022 and 2030.

Capitalized Costs related to oil and gas activities: The following table summarizes the costs incurred in our oil and gas interests for acquisition, exploration, and development activities for the three years ended August 31, 2011, 2010 and 2009.

Oil and Gas Interests	**2011**	2010	2009
Developed-Alberta, Canada			
Net book value at September 1	$ 314,000	$ 407,000	$ 448
Acquisition of 1354166 Alberta	-	-	538,995
Depletion	(23,136)	(38,370)	(26,638)
Change in asset retirement obligation estimates	1,600	-	-
Write down of oil and gas interests	(49,464)	(54,630)	(105,805)
Total developed, Alberta Canada	243,000	314,000	407,000
Undeveloped-Texas USA			
Net book value at September 1	5,695,290	-	-
Acquisition of oil and gas interests	-	212,780	-
Exploration expenditures	3,158,688	10,046	-
Asset retirement obligation	44,150	-	-
Acquisition of Dyami Energy	-	5,472,464	-
Total undeveloped, Texas, USA	8,898,128	5,695,290	-
Total developed and undeveloped	$ 9,141,128	$ 6,009,290	$ 407,000

Present Activities, Results of Exploration and Drilling: In August 2010, Dyami Energy commenced operations to drill its Dyami/Matthews #1-H well on the Matthews Lease to a measured depth of 8,563 feet, of which 5,114 feet was vertical depth into the Del Rio formation. The well was whipstocked at the top of the Austin Chalk formation and drilled with an 800 foot curve and extended horizontally 3,300 feet into the Eagle Ford shale formation. The well was logged extensively and 36 sidewall cores were taken from 4 key formations in descending order, the San Miguel, the Austin Chalk, the Eagle Ford and the Buda. The logs were interpreted by Weatherford International Ltd and the sidewall cores were analyzed by Core Laboratories and Weatherford. We are formulating a detailed frac design and completion plan for the Dyami/Matthews #1 H well.

On January 20, 2011 we commenced drilling our 100% working interest Murphy/Dyami #1 test well on its 2,637 gross acre Murphy Lease located in Zavala County, Texas. The well was drilled to to a vertical depth of 4,588 feet into the Buda formation. The well was logged and sidewall cores were taken from 5 key formations the Escondido, the Serpentine, the Eagle Ford shale, the Georgetown and the Buda. The logs were interpreted by Weatherford International Ltd. and the sidewall cores have been analyzed by Core Laboratories and we are formulating a completion program.

On March 29, 2011 we commenced drilling the Matthews/Dyami #3 well on the Matthews Lease, Zavala County, Texas. The well was drilled to a vertical depth of approximately 3,500 feet to the base of the San Miguel formation. Subsequently, we completed a nitrified acid injection operation and the heavy oil well has been placed on production testing.

On March 31, 2011 we entered into a Farmout Agreement (the “Farmout”) from surface to the base of the San Miguel formation (the “San Miguel”) on the Matthews Lease located in Zavala County, Texas. Under the Farmout, the farmee may spend up to US$1,050,000 on exploration and development of the San Miguel to earn a maximum of 42.50% working interest (31.875% net revenue interest). Under the terms of the Farmout, the farmee may earn an initial 25% of our working interest in the San Miguel by paying 100% of the costs to drill, complete, equip and perform an injection operation on a test well to a depth of approximately 3,500 feet (the “Initial Test Well”). After the performance of the Initial Test Well, the farmee may increase its working interest to 50% of our working interest by spending the entire $1,050,000 on additional operations on the San Miguel in a good faith effort to produce hydrocarbons. During the year ended August 31, 2011, we received US$647,536 from the farmee for costs related to the drilling, completion and injection operation of the Matthews/Dyami #3 well. As at August 31, 2011 we had not assigned any interest to the farmee in the San Miguel formation.

Subsequent to our year ended August 31, 2011, we commenced drilling its Matthews/Dyami #2H well located in Zavala County, Texas.

Governmental Regulation/Environmental Issues: Our oil and gas operations are subject to various Canadian and US governmental regulations. Matters subject to regulation include discharge permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells, and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas. The production, handling, storage, transportation and disposal of oil and gas, by-products thereof, and other substances and materials produced or used in connection with oil and gas operations are also subject to regulation under federal, state, provincial and local laws and regulations relating primarily to the protection of human health and the environment. To date, expenditures related to complying with these laws, and for remediation of existing environmental contamination, have not been significant in relation to the results of operations of our company. The requirements imposed by such laws and regulations are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations (See, Item 3.D Key Information - Risk Factors).

ITEM 4A UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 5 OPERATING AND FINANCIAL REVIEW AND PROSPECTS

The following discussion should be read in conjunction with our “Selected Financial Data” under Item 3 above, our Audited Consolidated Financial Statements for the fiscal years ended August 31, 2011, 2010 and 2009 and notes thereto included under “Item 17”. Unless otherwise indicated, discussion under this Item is based on Canadian dollars and is presented in accordance with Canadian Generally Accepted Accounting Principles (“GAAP”). For reference to differences between Canadian GAAP and United States Generally Accepted Accounting Principles (“US GAAP”) see Note 17 to our Audited Consolidated Financial Statements for the fiscal years ended August 31, 2011 and 2010.

Certain measures in this discussion and analysis do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles such as netback and other production figures and therefore are considered non-GAAP measures. Therefore these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional information regarding the Company’s liquidity and its ability to generate funds to finance its operations.

Certain statements made in this Item are forward-looking statements under the Reform Act. Forward- looking statements are based on current expectations that involve a numbers of risks and uncertainties, which could cause actual events or results to differ materially from those reflected herein. See, Item 3.D Key Information - Risk Factors for discussion of important factors, which could cause results to differ materially from the forward- looking statements below.

Overview

Eagleford Energy Inc. is amalgamated under the laws of the Province of Ontario. We are a reporting issuer with the United States Securities and Exchange Commission and our common shares trade on the Over-the-Counter Bulletin Board (OTCBB) under the symbol EFRDF.

Our business focus consists of acquiring, exploring and developing oil and gas interests. The recoverability of the amount shown for these properties is dependent upon the existence of economically recoverable reserves, the ability of the Company to obtain the necessary financing to complete exploration and development, and future profitable production or proceeds from disposition of such property. Our oil and gas interests are located in Alberta, Canada and Zavala County, Texas. We also holds a 0.3% net smelter return royalty on eight mining claims located in Red Lake Ontario which is carried on the Consolidated Balance Sheets at $Nil.

Our Audited Consolidated Financial Statements for the year ended August 31, 2011 and 2010 include the accounts of the Company, and our wholly owned subsidiaries 1354166 Alberta Ltd. and Dyami Energy from the date of acquisition August 31, 2010.

On November 12, 2009, our wholly owned subsidiary 1406768 Ontario Inc. changed its name to Eagleford Energy Inc. On November 30, 2009 we amalgamated with Eagleford Energy Inc. and upon the amalgamation our new name became Eagleford Energy Inc.

Capital Management

Our objectives when managing capital are to ensure we will have sufficient financial capacity, liquidity and flexibility to funds its operations, growth and ongoing exploration and development commitments on its oil and gas interests. We are dependent on funding these activities through debt and equity financings. Due to long lead cycles of our exploration activities, our capital requirements currently exceed our operation cash flow generated. As such we are dependent upon future financings in order to maintain our flexibility and liquidity and may from time to time be required to issue equity, issue debt, adjust capital spending or seek joint venture partners.

We manage the capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of any underlying assets in order to meet current and upcoming obligations. Current plans for the development commitments of our Texas leases include debt or equity financing or seeking and obtaining a joint venture partner.

The board of directors does not establish quantitative return on capital criteria for management, but rather relies on the expertise of our management and favourable market conditions to sustain future development of the business.

As at August 31, 2011and 2010 we consider our capital structure to comprise of shareholders equity and long-term debt.

Management reviews our capital management approach on an ongoing basis and believes that this approach, given the relative size of us, is reasonable.

There were no changes in our capital management during the period ended August 31, 2011.

We are not subject to any externally imposed restrictions on its capital requirements.

Critical Accounting Policies and Estimates and Change in Accounting Policies and Initial Adoption

Our significant accounting policies, estimates and changes to accounting policies are also described in the Notes to the Audited Consolidated Financial Statements for the fiscal years ended August 31, 2011, 2010, and 2009 (See Item 17 – Financial Statements). It is increasingly important to understand that the application of generally accepted accounting principles involves certain assumptions, judgments and estimates that affect reported amounts of assets, liabilities, revenues and expenses. The application of principles can cause varying results from company to company.

The most significant accounting policies that impact us relate to oil and gas accounting and reserve estimates.

Our consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada. The preparation of our consolidated financial statements in accordance with US GAAP have resulted in differences to the consolidated balance sheet and the consolidated statement of loss, comprehensive loss and deficit from the consolidated financial statements prepared using Canadian GAAP (see Reconciliation to Accounting Principles Generally Accepted in the United States below).

Summary of Significant Accounting Policies

Nature of Operations and Going Concern
Eagleford Energy Inc.'s ("Eagleford" or the "Company") business focus consists of acquiring, exploring and developing oil and gas interests. The recoverability of the amount shown for these properties is dependent upon the existence of economically recoverable reserves, the ability of the Company to obtain the necessary financing to complete exploration and development, and future profitable production or proceeds from disposition of such property. In addition the Company holds a 0.3% net smelter return royalty on 8 mining claim blocks located in Red Lake, Ontario which is carried on the consolidated balance sheets at nil. The Company's common shares trade on the OTCBB under the symbol EFRDF.

These consolidated financial statements have been prepared on a going concern basis which contemplates the realization of assets and the payment of liabilities in the ordinary course of business.

The Company has accumulated significant losses and negative cash flows from operations in recent years which raises doubt as to the validity of the going concern assumption. As at August 31, 2011, the Company had a working capital deficiency of $4,870,621 and an accumulated deficit of $2,469,792. The Company does not have sufficient funds to meet its liabilities for the ensuing twelve months as they fall due. In assessing whether the going concern assumption is appropriate, management takes into account all available information about the future, which is at least, but not limited to, twelve months from the end of the reporting period. The Company's ability to continue operations and fund its liabilities is dependent on management's ability to secure additional financing and cash flow. Management is pursuing such additional sources of financing and cash flow to fund its operations and obligations and while it has been successful in doing so in the past, there can be no assurance it will be able to do so in the future. Management is aware, in making its assessment, of material uncertainties related to events or conditions that may cast significant doubt upon the Company's ability to continue as a going concern. Accordingly, they do not give effect to adjustments that would be necessary should the Company be unable to continue as a going concern and therefore realize its assets and liquidate its liabilities and commitments in other than the normal course of business and at amounts different from those in the accompanying consolidated financial statements.

The Company plans to obtain additional financing by way of debt or the issuance of common shares or some other means to service its current working capital requirements, any additional or unforeseen obligations or to implement any future opportunities.

Significant Accounting Policies
These consolidated financial statements of Eagleford have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). The preparation of these consolidated financial statements in accordance with generally accepted accounting principles in United States ("US GAAP") have resulted in differences to the consolidated balance sheets and the consolidated statements of operations and comprehensive loss and consolidated statements of shareholders' equity from the consolidated financial statements prepared using Canadian GAAP (see Note 17 to the financial statements).

Principles of Consolidation
On November 12, 2009, the Company's wholly owned subsidiary, 1406768 Ontario Inc. changed its name to Eagleford Energy Inc. On November 30, 2009 the Company amalgamated with Eagleford Energy Inc. and continued operations as Eagleford Energy Inc. The consolidated financial statements include the accounts of Eagleford, the legal parent, together with its wholly owned subsidiaries, 1354166 Alberta Ltd., an Alberta operating company, and Dyami Energy LLC, a Texas limited liability exploration stage company. All inter-company account transactions have been eliminated on consolidation.

Oil and Gas Interests
The Company follows the successful efforts method of accounting for its oil and gas interests. Under this method, costs related to the acquisition, exploration, and development of oil and gas interests are capitalized. The Company carries as an asset, exploratory well costs if a) the well found has sufficient quantity of reserves to justify its completion as a producing well and b) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. If a property is not productive or commercially viable, its costs are written off to operations. Impairment of non-producing properties is assessed based on management's expectations of the properties.

Developed oil and gas reserves - Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction means is by not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expect to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on any undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at great distances;
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are schedules to be drilled within five years, unless the specific circumstances justify a longer time; and
(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Depletion and Depreciation
Depletion of oil and gas properties and depreciation of production equipment are calculated on the unit of production basis based on:

(a) total estimated proved reserves calculated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities;

(b) total capitalized costs, excluding undeveloped lands and unproved costs, plus estimated future development costs of proved undeveloped reserves; and

(c) relative volumes of oil and gas reserves and production, before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Impairment of Long-Lived Assets
The carrying values of property and equipment are reviewed for impairment whenever events or circumstances indicate that the recoverable amount may be less than the carrying value. The determination of when to recognize an impairment loss for a long-lived asset to be held and used is made when its carrying value exceeds the total undiscounted cash flows expected from its use and eventual disposition. When impairment is indicated, the amount of the impairment loss is determined as the excess of the carrying value of the amount over its fair value based on estimated discounted cash flows from use or disposition.

Revenue Recognition
Revenues from the production of oil and gas properties in which the Company has an interest with joint partners, are recognize, on the basis of the Company's working interest in those properties (the entitlement method), on receipt of a statement of account from the operators of the properties.

Environmental and Site Restoration Costs
The Company recognizes an estimate of the liability associated with an asset retirement obligation ("ARO") in the financial statements at the time the liability is incurred. The estimated fair value of the ARO is recorded as a long-term liability with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a straight-line basis over the estimated life of the asset. The liability amount is increased each reporting period due to the passage of time and the amount of accretion to operations in the period. The ARO can also increase or decrease due to changes in the estimates of timing of cash flows or changes in the original estimated undiscounted cost. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded.

Foreign Currencies
The functional and reporting currency of the Company is the Canadian dollar. Monetary assets and liabilities are translated at exchange rates in effect at the balance sheet date. Non-monetary assets are translated at exchange rates in effect when they were acquired. Revenue and expenses are translated at the approximate average rate of exchange for the year, except that amortization is translated at the rates used to translate related assets.

One of the Company's subsidiaries uses the US Dollar as the functional currency. However, this subsidiary is considered integrated to Eagleford Energy Inc's operations since it relies on the Company to fund its operations. Hence translation gains and losses of this subsidiary are charged to the consolidated statement of operations.

Marketable Securities
At each financial reporting period, the Company estimates the fair value of investments which are held-for-trading, based on quoted closing bid prices at the consolidated balance sheet dates or the closing bid price on the last day the security traded if there were no trades at the consolidated balance sheet dates and such valuations are reflected in the consolidated financial statements. The resulting values for unlisted securities whether of public or private issuers, may not be reflective of the proceeds that could be realized by the Company upon their disposition. The fair value of the securities at August 31, 2011 was $1 (2010 - $1).

Financial Instruments
All financial instruments are measured at fair value on initial recognition of the instrument. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the applicable accounting standards.

Cash and cash equivalents are designated as "held-for-trading" and is measured at fair value, which approximates carrying value.

Marketable securities are designated as "held-for-trading" and measured at fair value with unrealized gains and losses recorded in net income until the security is sold or if an unrealized loss is considered other than temporary, the unrealized loss is expensed.

Accounts receivable are designated as "loans and receivable" and are carried at amortized cost. Accounts payable and accrued liabilities, secured notes payable and shareholder loans are designated as "other financial liabilities" and are carried at amortized cost.

The CICA Handbook Section 3862 – "Financial Instruments – Disclosure", requires an entity to classify fair value measurements in accordance with an established hierarchy that prioritizes the inputs in valuation techniques used to measure fair value. The levels and inputs which may be used to measure fair value are as follows:

Level 1 – fair values are based on quoted prices in active markets for identical assets or liabilities;

Level 2 – fair values are based on inputs other than quoted prices that are observable for the asset or liability, either directly (as prices) or indirectly (derived from prices); or

Level 3 – applies to assets and liabilities for inputs that are not based on observable market data, which are unobservable inputs.

Cash Equivalents
Cash equivalents include trust accounts, and term deposits with maturities of less than three months.

Estimates and Measurement Uncertainty
The preparation of the consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the values and presentation of assets, liabilities, revenues, expenses and disclosures of contingencies and commitments. Such estimates primarily relate to unsettled transactions and events at the balance sheet date which are based on information available to management at each financial statement date. Actual results may differ from those estimated.

Areas where management is required to make significant estimates are as follows:

i. Depletion and impairment of Oil and Gas Interests are determined using estimates for resource reserves, and the impairment assessment of Oil and Gas Interests requires further assumptions for future commodity prices, royalties, operating costs, development costs, abandonment costs, and the fair value of unproven properties, all of which are inherently uncertain. To mitigate the risk that inappropriate assumptions are used, estimates are evaluated by independent reserve evaluators.

ii. The provision for asset retirement obligations requires management to estimate the timing and amount of cash flows required to retire its Oil and Gas Interests.

iii. The Company uses the Black-Scholes option pricing model to determine the fair value of stock options and common share purchase warrants granted. This model requires management to estimate the volatility of the Company's future share price, expected lives of stock options and warrants and future dividend yields.

iv. The recognition of future income tax assets requires judgment as to whether future taxable income will be sufficient to realize the benefit of these tax assets.

By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the consolidated financial statements for current and future periods could be significant.

Income Taxes
The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on temporary differences between financial reporting and tax bases of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes. Future income tax assets and liabilities are measured using substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. Future income tax assets are recognized in the financial statements if realization is considered more likely than not. A valuation allowance against future tax assets is provided to the extent that the realization of these future tax assets is not more likely than not.

Non-Monetary Transactions
Transactions in which shares or other non-cash consideration are exchanged for assets or services are measured at the fair value of the assets or services involved in accordance with Section 3831 ("Non-monetary Transactions") of the Canadian Institute of Chartered Accountants Handbook ("CICA Handbook").

Stock-Based Compensation
The Company follows a fair value based method of accounting for all Stock-based Compensation and Other Stock-based Payments to employees and non-employees. The fair value of all share purchase options is expensed over their vesting period with a corresponding increase to contributed surplus. Upon exercise of share purchase options, the consideration paid by the option holder, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital. The Company uses the Black-Scholes option valuation model to calculate the fair value of share purchase options at the date of grant.

The quoted market price of the Company's shares on the date of issuance under any stock compensation plan is considered as fair value of the shares issued.

Loss Per Share
Basic loss per share is calculated by dividing net loss (the numerator) by the weighted average number of common shares outstanding (the denominator) during the period. Diluted loss per share reflects the dilution that would occur if outstanding stock options and share purchase warrants were exercised or converted into common shares using the treasury stock method and are calculated by dividing net loss applicable to common shares by the sum of the weighted average number of common shares outstanding and all additional common shares that would have been outstanding if potentially dilutive common shares had been issued.

The inclusion of the Company's stock options and share purchase warrants in the computation of diluted loss per share would have an anti-dilutive effect on loss per share and are therefore excluded from the computation. Consequently, there is no difference between basic loss per share and diluted loss per share.

Warrants
When the Company issues Units under a private placement comprising common shares and warrants, the Company follows the relative fair value method of accounting for warrants attached to and issued with common shares of the Company. Under this method, the fair value of warrants issued is estimated using a Black-Scholes option price model. The fair value is then related to the total of the net proceeds received on issuance of the Common shares and the fair value of the warrants issued therewith. The resultant relative fair value is allocated to warrants from the net proceeds and the balance of the net proceeds is allocated to the Common shares issued.

Change In Accounting Policies And Future Accounting Pronouncements

Change in Accounting Policies
Business Combinations

In January 2009, the CICA issued Section 1582, "Business Combinations", Section 1601, "Consolidations", and Section 1602, "Non-Controlling Interests". These sections replace the former Section 1581, "Business Combinations", and Section 1600, "Consolidated Financial Statements", and establish a new section for accounting for a non-controlling interest in a subsidiary.

Sections 1582 and 1602 will require net assets, non-controlling interests and goodwill acquired in a business combination to be recorded at fair value and non-controlling interests will be reported as a component of equity. In addition, the definition of a business is expanded and is described as an integrated set of activities and assets that are capable of being managed to provide a return to investors or economic benefits to owners. Acquisition costs are not part of the consideration and are to be expensed when incurred. Section 1601 establishes standards for the preparation of consolidated financial statements. The company will adopt these standards concurrently with IFRS.

Future Accounting Pronouncements
Adoption of International Financial Accounting Standards ("IFRS")

On January 1, 2011, public companies in Canada were required to adopt IFRS.

Public companies in Canada were required to adopt IFRS for the years beginning on or after January 1, 2011. For the company, the adoption date is September 1, 2011.

Consequently, effective September 1, 2011, the Company adopted IFRS as the basis for preparing its consolidated financial statements. The company will prepare its consolidated financial statements for the first quarter ending November 30, 2011 in accordance with IFRS, which will include comparative data for the prior year also prepared in accordance with IFRS as well as an opening IFRS balance sheet at September 1, 2010.

The initial phase of implementation included conceptual application of the new rules, analysis of the Company's accounting data and assessment of key areas that may be impacted and a consideration of the exemptions allowed under IFRS1, first-time adoption of IFRS. In this phase, Property, Plant and Equipment, Exploration and Evaluation Assets, Impairment Testing and Asset Retirement Obligations were identified as key areas.

IFRS Conversion Plan
There are significant accounting policy changes anticipated on adoption of IFRS which are described in more detail below. Most adjustments required on transition to IFRS will be made retrospectively against opening retained earnings as of the date of the first comparative balance sheet being September 1, 2010. In July 2009, the International Accounting Standards Board ("IASB") issued amendments to IFRS 1 "First time adoption of IFRS" allowing additional exemptions for first-time adopters.

The IFRS conversion plan consists of three phases as identified below:

Phase 1 – Initial Scoping (Completed)
Eagleford's Management has undertaken a preliminary high-level scoping study to consider the potential impact of the implementation of IFRS on the Company's financial reporting. The initial scoping includes the identification of key differences between Canadian GAAP and IFRS, and high-level changes required in accounting policies, systems and processes.

Phase 2 – Detailed Assessment and Design (In progress)
Comprehensive documentation and analysis of changes in accounting standards, policies, processes and procedures identified on scoping from Phase 1.

Phase 3 – Implementation (In progress)
Implementation and execution of changes identified from Phase 2.

Potential Impact of IFRS Adoption
Significant differences that have been identified between Canadian GAAP and IFRS that will impact the Company's are:

- IFRS 1 - First -time adoption of IFRS;
- IAS 16 - Property, plant and equipment;
- IFRS 6 – Exploration and evaluation assets;
- IAS 36 - Impairment testing;
- IAS 37 – Provision, contingencies liabilities and contingencies assets (Decommissioning costs); and
- An increased level of disclosure requirements.

These differences have been identified based on the current IFRS standards issued and expected to be in effect on the date of transition. Certain IFRS standards may be modified, and as a result, the impact may be different than the Company's current expectations. Management is currently determining the financial statement impact of these standards. The impact on the consolidated financial statements is not reasonably determinable at this time.

IFRS 1 - First Time Adoption of IFRS
The transition to IFRS requires the Company to apply IFRS 1, which prescribes requirements for preparing IFRS compliant financial statements in the first reporting period after the changeover date (July 1, 2011). IFRS 1 includes a requirement for retrospective application of each IFRS standard as if they were always in effect. IFRS 1 also mandates certain exemptions for retrospective application and provides optional exemptions from retrospective application to ease the transition to IFRS in the transition year.

This standard will have a significant impact on Eagleford's consolidated financial statements, at least from the perspective of reconciliation from Canadian GAAP to IFRS. However, this standard has the potential to be most complex to implement and have the greatest financial statement impact depending on policies choices made by Eagleford.

IAS 16 - Property Plant and Equipment
Items of property, plant and equipment, which include petroleum and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. The cost of property, plant and equipment at the date of transition to IFRS using the revaluation model, are expected to be recorded at their previous Canadian GAAP carrying amount under successful efforts, as allowed under the IFRS 1.

When significant parts of an item of property, plant and equipment, including petroleum and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant and equipment, including petroleum and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized net within profit or loss.

The Company is currently evaluating the impact of this accounting standard.

IFRS 6 - Exploration and Evaluation Expenditures
Pre-acquisition expenditures on oil and gas assets are recognized as an expense in the statement of operations when incurred. In accordance with IFRS 6, exploration and evaluation costs are capitalized within intangible assets until the success or otherwise of the well or project has been established and subject to an impairment review. The costs of unsuccessful wells in an area are written off to the income statement: this is in accordance with the successful efforts accounting policy with Canadian GAAP but is also compatible with IAS 36 on the basis the asset is impaired.

Eagleford does not expect a significant material impact on its statement of financial position, however the Company is currently evaluating its policy options and applicable impact of these policies under IFRS.

IAS 36 - Impairment of Assets
IAS 36 uses the concept of cash generating units to accumulate asset carrying costs to test and measure impairment. IFRS will require impairment testing to be performed at the cash generating unit level, which is lower than the current cost center level.

In addition, IAS 36 uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of: value-in-use and fair value less costs to sell. Value-in-use is defined as the amount equal to the present value of future cash flows expected to be derived from the asset. In the absence of an active market, fair value less costs to sell may also be determined using discounted cash flows. The use of discounted cash flows under IFRS to test and measure asset impairment differs from Canadian GAAP, which uses undiscounted cash flows as an initial first step to test impairment.

Under IAS 36, impairment losses that were previously recognized may be reversed where circumstances change such that the impairment is reduced. This differs from Canadian GAAP, which prohibits the reversal of previously recognized impairment losses.

The Company is currently evaluating the impact of this accounting standard.

IAS 37 - Decommissioning Costs
Under IFRS, the recognition criteria for contingent liabilities are much more explicit than Canadian GAAP and may potentially require the booking of additional liabilities associated with the asset retirement obligations of Eagleford’s oil and gas assets. Liabilities for decommissioning and restoration are recognized for both legal and constructive obligations. Under IFRS, the estimated liability is calculated at each reporting period using estimates of risk-adjusted future cash outflows, discounted using the risk free rate whereas under Canadian GAAP the estimated liability is estimated using a credit-adjusted rate, rather than a risk free rate.

Changes in the estimated timing of cash flows necessary to discharge the obligation are added to or deducted from the cost of the related asset and the adjusted amounts are amortized prospectively over the estimated useful life of the asset. The measurement of the present value of the estimate (arising due to different discount rates used) is likely to be higher under IFRS as compared to Canadian GAAP.

Information Systems
It is expected that the conversion to IFRS will have a minimal impact on the Eagleford’s information system.

Reconciliation to Accounting Principles Generally Accepted In The United States

These consolidated financial statements have been prepared in accordance with "Canadian GAAP". Material variations in the accounting principles, practices and methods used in preparing these consolidated financial statements from "US GAAP" and in SEC Regulation S-X are described and quantified below.

The significant differences between Canadian GAAP and US GAAP which had any impact on the consolidated balance sheet and consolidated statement of cash flows are noted below.

Oil and Gas Interests

In applying the successful efforts method under US GAAP (Regulation S-X Article 4-10), the Company performs a ceiling test based on the same calculations used for Canadian GAAP except the Company is required to discount future net revenues from proved reserves at 10% as opposed to utilizing the fair market value and probable reserves are excluded. During the year an impairment loss of $219,464 (2010-$104,630) for US GAAP and an impairment loss of $49,464 (2010-$54,630) was recorded for Canadian GAAP.

If US GAAP was followed, the effect on the consolidated balance sheet would be as follows:

	2011	2010
Total assets according to Canadian GAAP	$ 9,478,226	$ 6,107,452
Additional impairment of oil and gas interests	(170,000)	(50,000)
Total assets according to US GAAP	$ 9,308,226	$ 6,057,452

	2011	2010
Total shareholders' equity according to Canadian GAAP	$ 4,220,299	$ 4,239,777
Deficit adjustment per US GAAP		
Additional impairment of oil and gas interests	(170,000)	(50,000)
Total shareholders' equity according to US GAAP	$ 4,050,299	$ 4,189,777

If US GAAP was followed, the effect on the consolidated statements of loss and comprehensive loss would be as follows:

	2011	2010	2009
Net loss according to Canadian GAAP	$ 752,557	$ 688,709	$ 328,861
Add: Additional impairment of oil and gas interests	170,000	50,000	73,638
Net loss according to US GAAP	$ 922,557	$ 738,709	$ 402,499
Loss per share, basic and diluted	$ (0.029)	$ (0.030)	$ (0.023)
Shares used in the computation of loss per share	31,927,228	24,687,130	17,646,295

Adoption of New Accounting Policies

FASB Accounting Standards Update ("ASU") No. 2010-13 was issued in April 2010, and amends and clarifies ASC 718 with respect to the classification of an employee share based payment award with an exercise price denominated in the currency of a market in which the underlying security trades. This ASU did not have a material effect on the Company.

In April 2010, the FASB issued ASU 2010-14, "Accounting for Extractive Activities — Oil & Gas". ASU 2010-14 amends paragraph 932-10-S99-1 due to SEC Release No. 33-8995, "Modernization of Oil and Gas Reporting." The amendments to the guidance on oil and gas accounting are effective August 31, 2010, and did not have a significant impact on the Company's financial position that, if it is unable to raise additional capital, it may find it necessary to substantially reduce or cease operations.

Future Accounting Pronouncements

In January 2010, FASB issued ASU 2010-06 "Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurement" was issued, which provides amendments to Subtopic 820-10 that requires new disclosures as follows:

1. Transfers in and out of Levels 1 and 2. A reporting entity should disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers.

2. Activity in Level 3 fair value measurements. In the reconciliation for fair value measurements using significant unobservable inputs (Level 3), a reporting entity should present separately information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than as one net number).

This Update provides amendments to Subtopic 820-10 that clarify existing disclosures as follows:

1. Level of disaggregation. A reporting entity should provide fair value measurement disclosures for each class of assets and liabilities. A class is often a subset of assets or liabilities within a line item in the statement of financial position. A reporting entity needs to use judgment in determining the appropriate classes of assets and liabilities.

2. Disclosures about inputs and valuation techniques. A reporting entity should provide disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements. Those disclosures are required for fair value measurements that fall in either Level 2 or Level 3.

This Update also includes conforming amendments to the guidance on employers' disclosures about postretirement benefit plan assets (Subtopic 715-20). The conforming amendments to Subtopic 715-20 change the terminology from major categories of assets to classes of assets and provide a cross reference to the guidance in Subtopic 820-10 on how to determine appropriate classes to present fair value disclosures. The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years.

In December 2010, the FASB issued ASU 2010-28 "Intangibles – Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test For Reporting Units With Zero or Negative Carrying Amounts" ("ASU 2010-28").Under ASU 2010-28, if the carrying amount of a reporting unit is zero or negative, an entity must assess whether it is more likely than not that goodwill impairment exists. To make that determination, an entity should consider whether there are adverse qualitative factors that could impact the amount of goodwill, including those listed in ASC 350-20-35-30. As a result of the new guidance, an entity can no longer assert that a reporting unit is not required to perform the second step of the goodwill impairment test because the carrying amount of the reporting unit is zero or negative, despite the existence of qualitative factors that indicate goodwill is more likely than not impaired. ASU 2010-28 is effective for public entities for fiscal years, and for interim periods within those years, beginning after December 15, 2010, with early adoption prohibited.

In December 2010, the FASB issued ASU 2010-29 "Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations" ("ASU 2010-29"). ASU 2010-29 specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments in this Update also expand the supplemental pro forma disclosures under Topic 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amended guidance is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Early adoption is permitted.

In April 2011, the FASB issued ASU No. 2011-02, A Creditor's Determination of Whether a Restructuring Is a Troubled Debt Restructuring, as codified in ASC 310, Receivables. The amendments in this update provide additional guidance to assist creditors in determining whether a restructuring of a receivable meets the criteria to be considered a troubled debt restructuring. The amendments in this update are effective for the period beginning on or after June 15, 2011, and should be applied retrospectively to the beginning of the annual period of adoption. The Company does not expect this update to have a material impact on its consolidated financial statements.

The Company will transition to IFRS on September 1, 2011 and will no longer be required to prepare a reconciliation to US GAAP. Accordingly, the Company has not assessed the impact of adopting future US accounting pronouncements with an application date of September 1, 2011 or beyond in its financial statements and disclosures.

Segmented Information
Our only segment is oil and gas exploration and production and includes two geographic areas, Canada and the United States. The accounting policies applied to our operating segments are the same as those described in the summary of significant accounting policies.

Geographic information:

The following is segmented information as at and for the year ended August 31, 2011:

	Year ended August 31, 2011		As at August 31, 2011	
	Interest and other income	Net (loss)	Oil and gas interests	Other assets
Canada	$ 71,786	$ (696,643)	$ 243,000	$ 264,611
United States	-	(55,914)	8,898,128	72,487
Total	$ 71,786	$ (752,557)	$ 9,141,128	$ 337,098

The following is segmented information as at and for the year ended August 31, 2010:

	Year ended August 31, 2010		As at August 31, 2010	
	Interest and other income	Net (loss)	Oil and gas interests	Other assets
Canada	$ 105,404	$ (688,709)	$ 314,000	$ 68,141
United States	-	-	5,695,290	30,021
Total	$ 105,404	$ (688,709)	$ 6,009,290	$ 98,162

Other Information
Additional information relating to us may be obtained or viewed from the System for Electronic Data Analysis and Retrieval at www.sedar.com and our future United States Securities and Exchange Commission filings can be viewed through the Electronic Data Gathering Analysis and Retrieval System (EDGAR) at www.sec.gov.

Share Capital and Contributed Surplus
Authorized:
Authorized:

Unlimited number of common shares
Unlimited non-participating, non-dividend paying, voting redeemable preference shares

Issued:

Common Shares	Number	Amount
Balance at August 31, 2008	10,471,739	$ 467,604
February 5, 2009 private placement (note a)	2,600,000	67,600
February 25, 2009 private placement (note b)	1,000,256	26,007
February 27, 2009 acquisition (note c)	8,910,564	231,675
February 27, 2009 debt settlement (note d)	1,250,000	32,500
Balance at August 31, 2009	24,232,559	825,386
Exercise of warrants (note e)	2,100,000	197,400
August 31, 2010 acquisition, net of transaction costs (note f)	3,418,467	2,794,398
Balance August 31, 2010	29,751,026	3,817,184
Exercise of warrants (note h)	3,710,346	722,572
Issued as compensation (note i)	100,000	95,800
Balance August 31, 2011	**33,561,372**	**$ 4,635,556**

(a) On February 5, 2009, the Company completed a non-brokered private placement of 2,600,000 units at a purchase price of $0.05 per unit for gross proceeds of $130,000. Each unit was comprised of one common share and one common share purchase warrant. Each warrant is exercisable until February 5, 2014, to purchase one common share at a purchase price of $0.07 per share. The amount allocated to warrants based on relative fair value using Black Scholes model was $62,400.

(b) On February 25, 2009, the Company completed a non-brokered private placement of 1,000,256 units at a purchase price of $0.05 per unit for gross proceeds of approximately $50,013. Each unit was comprised of one common share and one common share purchase warrant. Each warrant is exercisable until February 25, 2014 to purchase one common share at a purchase price of $0.07 per share. The amount allocated to warrants based on relative fair value using Black Scholes model was $24,006.

(c) On February 27, 2009, the Company acquired the issued and outstanding shares of 1354166 Alberta for total consideration of $445,528 satisfied by the issuance of 8,910,564 units of the Company at $0.05 per unit. Each unit consists of one common share and one common share purchase warrant exercisable at $0.07 to purchase one common share until February 27, 2014. The amount allocated to warrants based on relative fair value using Black Scholes model was $213,853.

(d) On February 27, 2009, the Company entered into an agreement with a non-related party, to settle debt in the amount of $62,500 through the issuance of a total of 1,250,000 units at an attributed value of $0.05 per unit. Each unit was comprised of one common share and one common share purchase warrant. Each warrant is exercisable until February 27, 2014 to purchase one common share at a purchase price of $0.07 per share. The amount allocated to warrants based on relative fair value using Black Scholes model was $30,000.

(e) During the year ended August 31, 2010, 1,100,000 warrants were exercised at $0.07 expiring February 5, 2014 for proceeds of $77,000 and 1,000,000 warrants were exercised at $0.07 expiring February 27, 2014 for proceeds of $70,000. The amount allocated to warrants based on relative fair value using Black Scholes model was $50,400.

(f) On August 31, 2010, the Company acquired all of the issued and outstanding membership interests of Dyami Energy and issued 3,418,467 units of the Company. Each unit consists of one common share and one half a common share purchase warrant. Each full warrant is exercisable at US$1.00 to purchase one common share until August 31, 2014. The fair value of the acquisition was estimated to be $4,218,812. Transaction costs of $35,581 were recorded as a reduction to share capital. The amount allocated to warrants based on relative fair value using Black Scholes model was $1,388,833.

(g) Effective June 10, 2010, the Company retained Gar Wood Securities, LLC (“Gar Wood”) to act as Investment Banker/Financial Advisor to the Company for a period of two years. Under the terms of the Gar Wood engagement, the Company agreed to pay a fee of 6% of the gross proceeds raised and issue 1,500,000 common share purchase warrants (the “Warrants”) as follows:

1,000,000 Warrants are exercisable at US$1.00 to purchase 1,000,000 common shares expiring on December 10, 2011 and issuable in three equal tranches on June 10, 2010, December 10, 2010 and June 10, 2011; and 500,000 Warrants are exercisable at US$1.50 to purchase 500,000 common shares expiring on June 10, 2012 and issuable in three equal tranches on June 10, 2010, December 10, 2010 and June 10, 2011. The amount allocated to warrants based on relative fair value using the Black Scholes model was $214,372 and $112,139 respectively and the total, $326,511 was recorded as compensation expense.

On November 5, 2010, the Company terminated the agreement dated June 10, 2010 with Gar Wood. As a result 36,430 warrants exercisable at $1.00 expiring December 10, 2011 were cancelled and 18,215 warrants were exercisable at $1.50 expiring June 10, 2012 were cancelled. The amount allocated to warrants based on relative fair value using the Black Scholes model was $23,315 and $12,204 respectively and the total, $35,519 was recorded as an increase to contributed surplus.

(h) During the year ended August 31, 2011, 500,000 common share purchase warrants were exercised at $0.07 expiring February 5, 2014 for proceeds of $35,000. The amount allocated to warrants based on relative fair value using the Black Scholes model was $12,000; 600,000 common share purchase warrants were exercised at $0.07 expiring February 25, 2014 for proceeds of $42,000. The amount allocated to warrants based on relative fair value using the Black Scholes model was $14,400; 35,346 common share purchase warrants were exercised at $0.07 expiring February 27, 2014 for proceeds of $2,475. The amount allocated to warrants based on relative fair value using the Black Scholes model was $822; and 2,575,000 common share purchase warrants were exercised at $0.20 expiring April 14, 2011 for proceeds of $515,000. The amount allocated to warrants based on relative fair value using the Black Scholes model was $100,875.

(i) On April 29, 2011, the Company entered into a consulting agreement with a service provider to provide corporate marketing and public relations to the Company for a period of six months. As compensation, the Company issued 100,000 common shares and 50,000 common share purchase warrants exercisable at US $1.25 per common share expiring May 4, 2012. The amount allocated to common shares was based on the share price at the time of issuance, amounting to $95,800 and $37,054 for the warrants based on the estimated fair value using the Black Scholes pricing model. $88,569 was recorded as marketing and public relations expense and $44,285 was recorded as prepaid expenses at August 31, 2011.

The following table summarizes the changes in warrants for the years then ended:

Warrants	2011 Number of Warrants	2011 Weighted Average Price	2010 Number of Warrants	2010 Weighted Average Price	2009 Number of Warrants	2009 Weighted Average Price
Outstanding beginning of year	16,445,053	$ 0.22	16,335,820	$ 0.09	2,575,000	$ 0.20
Issued	50,000	1.25	2,209,233	1.04	13,760,820	0.07
Exercised	(2,575,000)	0.20	(2,100,000)	0.07	-	-
Exercised	(1,113,346)	0.07	-	-	-	-
Cancelled	(36,430)	1.00	-	-	-	-
Cancelled	(18,215)	1.50	-	-	-	-
Outstanding end of year	12,730,062	$ 0.24	16,445,053	$ 0.22	16,335,820	$ 0.09

The following table summarizes the outstanding warrants as at August 31, 2011:

Date	Number of Warrants	Note	Exercise Price		Expiry Date	Warrant Value ($)
	1,000,000	(note a, e, h)	$	0.07	February 5, 2014	$ 24,000
	400,256	(note b, h)	$	0.07	February 25, 2014	9,606
	9,125,218	(note c, d, e, h)	$	0.07	February 27, 2014	219,031
	296,903	(note g)	US$	1.00	December 10, 2011	191,057
	148,452	(note g)	US$	1.50	June 10, 2012	99,935
	1,709,233	(note f)	US$	1.00	August 31, 2014	1,388,833
	50,000	(note i)	US$	1.25	May 4, 2012	37,054
Balance August 31, 2011	12,730,062					$ 1,969,516

The fair value of the warrants issued during the year ended August 31, 2011, 2010 and 2009 were estimated on the date of issue using the Black-Scholes pricing model with the following assumptions:

Black-Scholes Assumptions used	2011
Risk-free interest rate	1.7%
Expected volatility	254%
Expected life (years)	1
Dividend yield	0%
Fair value of the warrants issued on May 4, 2011	$ 0.74

Black-Scholes Assumptions used	2010
Risk-free interest rate	3%
Expected volatility	234%
Expected life (years)	4
Dividend yield	0%
Fair value of the warrants issued on June 10, 2010	$ 0.65
Fair value of the warrants issued on August 31, 2010	$ 0.81

Black-Scholes Assumptions used	2009
Risk-free interest rate	3%
Expected volatility	170%
Expected life (years)	4
Dividend yield	0%
Fair value of the warrants issued on February 5, 2009	$ 0.05
Fair Value of the warrants issued on February 25, 2009	$ 0.05
Fair Value of the warrants issued on February 27, 2009	$ 0.05

The weighted average basic and diluted shares outstanding at August 31, 2011, 2010 and 2009 is as follows:

Weighted Average Shares Outstanding	2011	2010	2009
Weighted average shares outstanding, basic	31,927,228	24,687,130	17,646,295
Dilutive effect of warrants	13,273,114	16,008,996	9,749,557
Weighted average shares outstanding, diluted	45,200,342	40,696,126	27,395,852

The effects of any potential dilutive instruments on loss per share related to the outstanding warrants are anti-dilutive and therefore have been excluded from the calculation of diluted loss per share.

Stock Option Plan

The Company has a stock option plan to provide incentives for directors, officers and consultants of the Company. The maximum number of shares, which may be set aside for issuance under the stock option plan, is 6,170,205 common shares. To date, no options have been issued.

Contributed Surplus

Contributed surplus transactions for the respective years are as follows:

		Amount
Balance, August 31, 2008 and 2009	$	38,000
Imputed interest		5,750
Balance, August 31, 2010		43,750
Warrants cancelled		35,519
Imputed interest		5,750
Balance, August 31, 2011	$	85,019

Overall Performance

Revenue for the year ended August 31, 2011 was down $33,588 to $71,786 compared to $105,374 for the same period in 2010. The decrease in revenue during 2011 is attributed to lower production volumes and lower commodity prices received. Net loss and comprehensive loss for the twelve months ended August 31, 2011 was $752,557 compared to $688,709 for the comparable twelve month period in 2010. The increase in loss during 2011 was primarily related to decreases in revenue and increases in administrative expenditures including interest costs which were partially offset by a gain on foreign exchange and a gain on disposal of marketable securities.

For the year ended August 31, 2011 our cash position increased by $121,490 to $165,266 compared to cash of $43,776 at August 31, 2010. At August 31, 2011 our accounts receivable was $127,546 representing an increase of $74,486 compared to $53,060 at August 31, 2010. Prepaid expenses and deposits at August 31, 2011 were $44,285 compared to Nil in the prior period.

For the year ended August 31, 2011 current liabilities increased by $4,365,295 to $5,207,719 compared to $842,424 at August 31, 2010. Long term liabilities decreased by $975,043 to $50,208 compared to $1,025,251 at August 31, 2010.

We have a working capital deficiency of $4,870,621 at August 31, 2011 compared to a working capital deficiency of $744,262 at August 31, 2010.

During the year ended August 31, 2011, common share purchase warrants were exercised for proceeds of $594,475.

During the year ended August 31, 2011 we received $2,878,736 and issued promissory notes bearing interest at 10% per annum. Interest is payable annually on the anniversary date of the notes.

During the year ended August 31, 2011 we paid $98,440 of secured notes and $110,000 loan payable.

Through Dyami Energy, we commenced operations in August 2010 to drill an initial Eagle Ford shale test well on the Matthews Lease in Zavala County, Texas. The Matthews/Dyami #1H well was drilled to a measured depth of approximately 8,563, feet which includes a 3,300 foot “in section” lateral into the Eagle Ford shale formation. A shot point sleeve was installed in the Eagle Ford shale formation to facilitate a multi stage frac completion.

On January 20, 2011 we spud its 100% working interest Murphy/Dyami #1 test well on its 2,637 gross acre Murphy Lease located in Zavala County, Texas. The well was drilled to a vertical depth of approximately 4,588 feet into the Buda formation.

On March 29, 2011 we spud the Matthews/Dyami #3 well on the Matthews Lease, Zavala County, Texas. The well was drilled to a vertical depth of approximately 3,500 feet to the base of the San Miguel formation. We completed a nitrified acid injection operation and the well has been placed on production testing.

On March 31, 2011 we entered into a Farmout Agreement (the "Farmout") from surface to the base of the San Miguel formation (the "San Miguel") on the Matthews Lease located in Zavala County, Texas. Under the Farmout, the farmee may spend up to US$1,050,000 on exploration and development of the San Miguel formation to earn a maximum of 42.50% working interest (31.875% net revenue interest). Under the terms of the Farmout, the farmee may earn an initial 25% of our working interest in the San Miguel by paying 100% of the costs to drill, complete, equip and perform an injection on a vertical test well to a depth of approximately 3,500 feet (the "Initial Test Well"). After the performance of the Initial Test Well, the farmee may increase its working interest to 50% of our working interest by spending the entire $1,050,000 on additional operations on the San Miguel in a good faith effort to produce hydrocarbons.

On July 30, 2011 we spud its second 100% working interest Murphy/Dyami #2 well on its Murphy Lease located in Zavala County, Texas. The well was drilled to a vertical depth of approximately 4,415 feet.

We are formulating detailed frac and completion programs for the Matthews/Dyami #1H, Murphy/Dyami #1 and Murphy/Dyami #2 wells.

For the year ended August 31, 2011 we incurred $3,158,688 in exploration expenditures related to our Matthews and Murphy Leases in Zavala County, Texas.

We expect to apply additional capital to further enhance our property interests. As part of our oil and gas development program, management anticipates further expenditures to expand our existing portfolio of proved reserves. Amounts expended on future exploration and development is dependent on the nature of future opportunities evaluated by us. These expenditures may be funded through cash held by us or through cash flow from operations. Any expenditure which exceeds available cash will be required to be funded by additional share capital or debt issued by us, or by other means. Our long-term profitability will depend upon its ability to successfully implement its business plan.

Our past primary source of liquidity and capital resources has been shareholder loans, cash flow from oil and gas operations and proceeds from the issuance of common shares.

Selected Financial Information

The following table reflects the summary of operating results for the years ended August 31, 2011, 2010 and 2009.

Presented Pursuant to Canadian Generally Accepted Accounting Principles
(CANADIAN $, Except Per Share Data)

For the years ended August 31,		**2011**		**2010**		**2009**
Revenue	$	71,786	$	105,374	$	56,199
Net loss and comprehensive loss	$	(752,557)	$	(688,709)	$	(328,861)
Loss per share basic and diluted	$	(0.024)	$	(0.028)	$	(0.019)
Assets	$	9,478,226	$	6,107,452	$	600,327
Long term liabilities	$	50,208	$	1,025,251	$	3,634

Selected Financial Information should be read in conjunction with the discussion below and "Critical Accounting Policies and Estimates" above.

August 31, 2011 – 2010
For the year ended August 31, 2011 revenue decreased compared to revenue in the prior period as a result of natural production declines and lower natural gas prices. The net loss for the year ended August 31, 2011 was $752,557 up $63,848 compared to a net loss of $688,709 in 2010. The increase in loss and comprehensive loss for fiscal 2011 was primarily attributed to interest costs of $265,889 versus $5,750 in the prior period, an increase of $57,789 in professional fees, an increase of $72,090 in head office costs, an increase in salaries and wages of $44,061 and an increase of $88,569 in marketing and public relations. The overall higher administrative costs were partially offset by a gain on foreign exchange, a gain on disposal of marketable securities and a decrease in consulting fees. For the year ended August 31, 2011 assets increased significantly up $3,370,774 to $9,478,226 compared to $6,107,452 for the same period in 2010. The increase in assets is primarily attributed to exploration expenditures incurred of $3,158,688 on the Matthews and Murphy leases in Zavala County, Texas. Long term liabilities decreased in fiscal 2011 compared to 2010 as a result of a US $960,000 long term secured note being moved into current liabilities.

August 31, 2010 - 2009

For the year ended August 31, 2010 revenue increased substantially compared to revenue in the prior period as a result of a full twelve months of operations of 1354166 Alberta compared to six months of operations in 2009. The net loss and comprehensive loss for the year ended August 31, 2010 was $688,709 up $359,848 compared to a net loss of $328,861 in 2009. The increase in loss for fiscal 2010 was primarily attributed to a consulting fee of $326,511 recorded upon the issuance of warrants versus $Nil in the prior period, an increase of $46,074 in professional fees, an increase of $25,613 in head office costs, an increase of $20,241 in transfer and register costs all of which were offset by higher revenues and a reduction of $51,175 in the write down of oil and gas interests. For the year ended August 31, 2010 assets increased significantly up $5,507,125 to $6,107,452 compared to $600,327 for the same period in 2009. The increase in assets is attributed to the acquisition of a 10% working interest in the Matthews lease, Zavala County, Texas and the acquisition of 100% of the membership shares of Dyami Energy.

August 31, 2009-2008

For the year ended August 31, 2009 revenue increased substantially compared to revenue in the comparable period in 2008 as a result of the acquisition of 1354166 Alberta Ltd. The net loss comprehensive loss for the year ended August 31, 2009 was $328,861 compared to a net loss of $50,514 in 2008. The increase in net loss and comprehensive loss for the year ended August 31, 2009 was primarily a result of the write-down of oil and gas interests of $105,805, an increase in professional fees of $80,162, an increase in transfer agent and registrar costs of $20,479, an increase management fees of $6,000 and increase in general and office of $4,897. In addition the Company incurred higher operating costs and depletion for the year ended August 31, 2009. For the year ended August 31, 2009 assets increased by $391,841 to $600,327 compared to assets of $208,486 for the same period in 2008. The increase in assets for the year ended August 31, 2009 was primarily attributed to acquisition of 1354166 Alberta Ltd.

A. OPERATING RESULTS

THE FOLLOWING DISCUSSION OF OUR RESULTS OF OPERATIONS IS A COMPARISON OF OUR FISCAL YEAR ENDED AUGUST 31, 2011 VERSUS AUGUST 31, 2010 AND AUGUST 31, 2010 VERSUS AUGUST 31, 2009.

Presented Pursuant to Canadian Generally Accepted Accounting Principles
(CANADIAN $, Except Per Share Data)

	For the Years Ended August 31					
Historical Production		**2011**		**2010**		**2009**
Natural gas – mcf/d		53		68		45
Historical Prices						
Natural Gas - $/mcf	$	3.68	$	4.22	$	3.42
Royalties costs - $/mcf	$	0.76	$	0.98	$	0.63
Production costs - $/mcf	$	2.68	$	2.62	$	3.28
Net back - $/mcf	$	0.24	$	0.62	$	(0.49)
Operations						
Revenue	$	71,786	$	105,374	$	56,199
Net loss and comprehensive loss	$	(752,577)	$	(688,709)	$	(328,861)
Loss per share basic and diluted	$	(0.024)	$	(0.028)	$	(0.019)

Production Volume

For the year ended August 31, 2011 average natural gas sales volumes decreased to 53 mcf/d compared to 68 mcf/d in the comparable twelve month period in 2010. Total production volume for the year ended August 31, 2011 was 19,500 mcf compared to 24,950 mcf for the same period in 2010. The decrease in average sales volume per day and total production volume for the year ended August 31, 2011 was a result of natural production declines.

For the year ended August 31, 2010 average natural gas sales volumes increased to 68 mcf/d compared to 45 mcf/d in the comparable twelve month period in 2009. Total production volume for the year ended August 31, 2010 was 24,950 mcf compared to 16,412 mcf for the same period in 2009. The increase in average sales volume per day and total production volume for the year ended August 31, 2010 was a result of a full year of operations from 1354166 Alberta versus six months of operations from 1354166 Alberta in 2009.

Commodity Prices

For the year ended August 31, 2011 average natural gas prices received per mcf decreased by 13% to $3.68 compared to $4.22 for the twelve months ended August 31, 2010. The decrease in average natural gas prices received was attributed to lower commodity prices for natural gas for the year ended August 31, 2011.

For the year ended August 31, 2010 average natural gas prices received per mcf increased by 23% to $4.22 compared to $3.42 for the twelve months ended August 31, 2009. The increase in average natural gas prices received was attributed to higher commodity prices for natural gas for the year ended August 31, 2010.

Revenue

Revenue for the year ended August 31, 2011 was down $33,588 to $71,786 compared to $105,374 for the same period in 2010. The decrease in revenue for the year ended August 31, 2011 was attributed to lower production volume due to natural production declines and lower commodity prices received for natural gas.

Revenue for the year ended August 31, 2010 was up $49,175 to $105,374 compared to $56,199 for the same period in 2009. The increase in revenue for the year ended August 31, 2010 is attributed to a full twelve months of operations of 1354166 Alberta versus six months of operations from 1354166 Alberta for the same period in 2009.

Operating Costs

For the year ended August 31, 2011 operating costs were $67,611 down $34,979 compared to operating costs of $102,590 for the year ended August 31, 2010. The decrease in operating costs for the year ended August 31, 2011 was attributed lower production volumes.

For the year ended August 31, 2010 operating costs were $102,590 up $19,403 compared to operating costs of $83,187 for the year ended August 31, 2009. The increase in operating costs for the year ended August 31, 2010 was attributed to a full twelve months of operations of 1354166 Alberta. For the year ended August 31, 2009 the Company incurred repair and maintenance costs of $22,111 due to a ruptured pipeline.

Depletion

Depletion for the year ended August 31, 2011 decreased by $15,234 to $23,136 compared to $38,370 for the year ended August 31, 2010. The decrease in depletion for the year ended August 31, 2011 was a result of lower production volume.

Depletion for the year ended August 31, 2010 increased by $11,732 to $38,370 compared to $26,638 for the year ended August 31, 2009. The increase in depletion for the year ended August 31, 2010 was a result of higher production volume attributed to a full twelve months of operations of 1354166 Alberta.

Administrative Expenses

Administrative expenses for the year ended August 31, 2011 were $741,596 compared to $653,153 for the year ended August 31, 2010. The increase in expenses during fiscal 2011 was primarily attributed to interest costs recorded of $265,889 versus $5,750 in the prior period, an increase of $57,789 in professional fees, an increase of $72,090 in head office costs, and increase of $88,569 in marketing and public relations, an increase in salaries and wages of $44,061 an increase in management fees of $32,250 and an increase in transfer and registrar costs of $16,354. During the year ended August 31, 2011 we recorded an impairment of oil and gas interests of $49,464 compared to $54,630 in the comparable period in 2010. The higher administrative expenses during fiscal 2011 were partially offset by a gain on foreign exchange of $164,800 and a reduction in consulting fees of $326,511 compared to fiscal 2010. The increase in overall administrative expenses for the year ended August 31, 2011 is a result of the increased operations by us.

Administrative expenses for the year ended August 31, 2010 were $653,153 compared to $276,815 for the year ended August 31, 2009. The increase in expenses during fiscal 2010 was primarily attributed to a consulting fee of $326,511 recorded upon the issuance of warrants versus $Nil in the prior period in 2009, an increase in professional fees of $46,074 to $152,844 compared to 106,770 in 2009, an increase in head office costs of $25,613 to $41,738 compared to $16,125 in 2009, and an increase in transfer and register costs of $20,241 to $45,206 compared to $24,965 in 2009. In addition we recorded imputed interest of $5,750 versus $Nil in the prior period in 2009.These higher costs in 2010 were partially offset by a reduction in the write down of oil and gas interests of $51,175 to $54,630 when compared to $105,805 during fiscal 2009 and a reduction of general and office costs of $2,676 to $2,474 when compared to $5,150 in fiscal 2009. Higher administrative expenses during the fiscal 2010 are attributed to increased operations and the acquisition of Dyami Energy.

Gain on Disposal of Marketable Securities
During the year ended August 31, 2011 we recorded a gain on disposal of marketable securities of $8,000 versus $Nil for the comparable period in 2010.

During the year ended August 31, 2010 we recorded a gain on disposal of marketable securities of $Nil versus $Nil for the comparable period in 2009.

Interest Income
For the year ended August 31, 2011 interest income was $Nil compared to $30 for the comparable period in 2010.

For the year ended August 31, 2010 interest income was $30 compared to$1,580 for the comparable period in 2009.

The decreases in interest income during fiscal 2011 and 2010 are attributed to decreases in cash held by the us during the respective periods.

Net Loss and Comprehensive Loss for the Year
Net loss for year ended August 31, 2011 was $752,557 up $63,848 or 9% compared to a net loss of $688,709 for the year ended August 31, 2010. The increase in net loss and for the year ended August 31, 2011 was primarily related to a decrease in revenue and increases in administrative expenses.

Net loss for year ended August 31, 2010 was $688,709 up $359,848 or 109% compared to a net loss of $328,861 for year ended August 31, 2009. The increase in net loss and comprehensive loss for the year ended August 31, 2010 was primarily related to increased administrative costs which included a consulting fee of $326,511 recorded upon the issuance of warrants.

Net Loss per Share
The net loss per share for the year ended August 31, 2011 was $0.024 compared to a net loss per share of $0.028 for the same twelve month period in 2010.

The net loss per share for the year ended August 31, 2010 was $0.028 compared to a net loss per share of $0.019 for the same twelve month period in 2009.

Capital Expenditures
For the year ended August 31, 2011 we incurred exploration expenditures of $3,158,688 on our Matthews and Murphy Leases located in Zavala County, Texas.

We expect that our capital expenditures will increase in future reporting periods as we incur capital expenditures to explore and develop our oil and gas properties.

Financing Activities
During the year ended August 31, 2011, 500,000 of our common share purchase warrants were exercised at $0.07 expiring February 5, 2014 for proceeds of $35,000; 625,247 of our common share purchase warrants were exercised at $0.07 expiring February 27, 2014 for proceeds of $44,475; and 2,575,000 of our common share purchase warrants were exercised at $0.20 expiring April 14, 2011 for proceeds of $515,000.

During the year ended August31, 2011 we received $2,878,736 and issued demand promissory notes bearing interest at 10% per annum. Interest is payable annually on the anniversary date of the notes.

During the year ended August 31, 2011 we paid $98,440 of secured notes and $110,000 loan payable.

Summary of Quarterly Results

The following tables reflect the summary of quarterly results for the years ended August 31, 2011, August 31, 2010 and August 31, 2009.

For the quarter ending	2011 August 31	2011 May 31	2011 February 28	2010 November 30
Revenue	$ 17,925	$ 17,826	$ 18,936	$ 17,099
Net loss and comprehensive loss	$ (295,381)	$ (241,814)	$ (116,370)	$ (98,992)
Loss per share basic and diluted	$ (0.010)	$ (0.007)	$ (0.004)	$ (0.003)

Revenue for the four quarters fluctuated as a result of changes in production volume and commodity prices received. The increase in loss for the quarter ended May 31, 2011 was attributed to higher administrative expenses including marketing and public relations of $88,569 and increases in interest expense of $74,864. The increase in loss for the quarter ended August 31, 2011 was attributed to higher administrative expenses including increases in interest expense of $86,845 and an increase in professional fees for year-end audit costs and costs associated with the evaluation of our reserves. In addition, we incurred a write down of oil and gas interests of $49,464.

For the quarter ending	2010 August 31	2010 May 31	2010 February 28	2009 November 30
Revenue	$ 23,363	$ 19,291	$ 36,461	$ 26,259
Net loss and comprehensive loss	$ (496,520)	$ (75,144)	$ (36,746)	$ (80,299)
Loss per share basic and diluted	$ (0.020)	$ (0.003)	$ (0.002)	$ (0.014)

Revenue for the four quarters in 2010 fluctuated as a result of changes in production volume and commodity prices received. The increase in net loss and comprehensive loss for the quarter ending August 31, 2010 was primarily attributed to us recording a consulting fee of $326,511 upon the issuance of warrants and higher administrative expenses due increased operations and the acquisition of Dyami Energy. During the fourth quarter we incurred an increase in professional fees for year-end audit costs and costs associated with the evaluation of our reserves.

For the quarter ending	2009 August 31	2009 May 31	2009 February 28	2008 November 30
Revenue	$ 23,078	$ 32,796	$ 260	$ 65
Net loss and comprehensive loss	$ (249,967)	$ (62,554)	$ (9,721)	$ (6,619)
Loss per share basic and diluted	$ (0.013	$ (0.005)	$ (0.001)	$ (0.001)

Revenue for the quarters for the May and August 2009 increased as a result of the acquisition of 1354166 Alberta Ltd. The increase in net loss and comprehensive loss for the quarter ending August 31, 2009 was primarily attributed to a write down of oil and gas interests, an increase in professional fees including year-end audit costs, transfer and registrar costs, office and general expenses, management fees and head office services, and costs associated with the evaluation of our reserves.

Fourth Quarter Results August 31, 2011Versus August 31, 2010

Production Volume

For the three months ended August 31, 2011 average natural gas sales volumes were 53 mcf/d compared to 68 mcf/d for the comparable period in 2010. Total production volume for the three months ended August 31, 2011 was 4,957 mcf compared to 6,227 mcf for the same three month period ending August 31, 2010. The decrease in production volume in 2011 is primarily related to natural production declines from our Botha, Alberta gas unit.

Commodity Prices

For the three months ended August 31, 2011 average natural gas sales prices received per mcf decreased to $3.62 compared to $3.75 for the three month period ended August 31, 2010.

Revenue

Revenue decreased by $5,438 to $17,925 for the three months ending August 31, 2011 compared to $23,363 for the three months ending August 31, 2010. Lower commodity prices received and lower production volume was responsible for the decrease in revenue.

Operating Costs
Operating costs were $4,761 for the three months ended August 31, 2011 compared to $50,102 for the three months ending August 31, 2010. The decrease in operating costs for the three month ended August 31, 2011 is due to lower production volume and a credit received from the operator in the current period.

Depletion
Depletion for the three months ending August 31, 2011 was $5,881 compared to depletion of $12,526 for the three months ending August 31, 2010. The decrease in depletion for the three months ended August 31, 2011 was a result of lower production volume.

Administrative Expenses
For the three months ending August 31, 2011 administrative expenditures were down $166,666 to $310,664 compared to $477,330 for the same period in 2010. The primary decrease in administrative expenses for the three months ending August 31, 2011 relate to consulting fee expense in the amount of $Nil compared to $326,511 in the prior period three month in 2010. The decrease in administrative expenditures were partially offset by a foreign exchange loss of $36,600 in the current period compared to $Nil in 2010, interest expense of $86,845 in the current period compared to $5,750 in the prior three month period, an increase in management fees of $17,250 to $18,750 for the three months ended August 31, 2011 compared to $1,500 in the three month period ended August 31, 2010 and an increase in professional fees of $7,400 to $55,958 compared to 48,558 in the prior period in 2010.

Gain on Disposal of Marketable Securities
During the three months ended August 31, 2011 we recorded a gain on disposal of marketable securities of $8,000 versus $Nil for the comparable period in 2010.

Net loss and comprehensive loss for the period
Net loss and comprehensive loss for the three months ending August 31, 2011 was $295,381 down $201,139 compared to $496,520 for the prior period in 2010.

Loss per share
The loss per share for the three months ending August 31, 2011 was $0.009 compared to $0.020 for the comparative same three month period in 2010.

B. LIQUIDITY AND CAPITAL RESOURCES

Cash as of August 31, 2011 was $165,266 compared to cash of $43,776 at August 31, 2010. During the year ended August 31, 2011 we received proceeds from the exercise of common share purchase warrants in the amount of $594,475 and received $2,878,736 and issued demand promissory notes bearing interest at a rate of 10% per annum.

For the year ended August 31, 2011 the primary use of funds was related to exploration expenditures incurred of $3,158,688 for our Matthews Lease and Murphy Lease located in Zavala County, Texas. In addition, we paid $98,440 in secured notes and repaid $110,000 loan payable. Our working capital deficiency at August 31, 2011 is $4,870,621 compared to a working capital deficiency of $744,262 at August 31, 2010.

Our current assets of $337,098 as at August 31, 2011 ($98,162 as of August 31, 2010) include the following items: cash $165,266 ($43,776 as of August 31, 2010); marketable securities $1 ($1 as of August 31, 2010); accounts receivable $127,546 ($53,060 as of August 31, 20010); due from related party $Nil ($1,325 as of August 31, 2010) and prepaid expenses and deposits of $44,285 (Nil as of August 31, 2010).

Our current liabilities of $5,207,719 as of August 31, 2011 ($842,424 as of August 31, 2010) include the following items: accounts payable $1,258,839 ($488,741 as of August 31, 2010); due to shareholders $2,936,236 ($57,500 as of August 31, 2010); loan payable $Nil ($110,000 as of August 31, 2010); and secured notes payable of $1,012,644 ($186,183 as of August 31, 2010).

At August 31, 2011 we had outstanding the following common share purchase warrants: 10,525,474 warrants exercisable at $0.07 per share; 296,903 warrants exercisable at US$1.00 per share; 148,452 warrants exercisable at US$1.50 per share; 1,709,233 warrants exercisable at US$1.00 per share; and 50,000 warrants exercisable at US$1.25. If any of these common share purchase warrants are exercised it would generate additional capital for us.

Management of the Company recognizes that cash flow from operations is not sufficient to expand its oil and gas operations and reserves or meet its working capital requirements. We have liquidity risk which necessitates us to obtain debt financing, enter into joint venture arrangements, or raise equity. There is no assurance the we will be able to obtain the necessary financing in a timely manner.

Our past primary source of liquidity and capital resources has been loans and advances, cash flow from oil and gas operations, proceeds from the sale of marketable securities and the issuance of common shares.

If we issue additional common shares from treasury it would cause the current shareholders of the Company dilution.

Outlook and Capital Requirements
A part of our oil and gas development program, we anticipate further expenditures to expand our existing portfolio of proved reserves. Amounts expended on future exploration and development are dependent on the nature of future opportunities evaluated by us. Any expenditure which exceeds available cash will be required to be funded by additional share capital or debt issued by us, or by other means. Our long-term profitability will depend upon our ability to successfully implement our business plan.

C. RESEARCH AND DEVELOPMENT, PATENTS AND LICENSES

We do not engage in research and development activities.

D. TREND INFORMATION

Seasonality

Our oil and gas operations is not a seasonal business, but increased consumer demand or changes in supply in certain months of the year can influence the price of produced hydrocarbons, depending on the circumstances. Production from our oil and gas properties is the primary determinant for the volume of sales during the year.

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

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

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

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

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

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

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the global economy. Market events and conditions in recent years including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions have caused significant volatility to commodity prices. These conditions caused a loss of confidence in the global credit and financial markets. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and may impact the performance of the global economy going forward. The recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and result in high volatility in the stock market.

E. OFF-BALANCE SHEET ARRANGEMENTS

There are no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes of financial condition, revenues, or expenses, results of operations, liquidity, capital expenditures or capital resources, which individually or in the aggregate are material to our investors.

F. TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The following table illustrates our contractual obligations as at August 31, 2011.

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Secured notes payable current (1)	$ 1,012,644	$ 1,012,644	$ -	$ -	$ -
Asset retirement obligations	50,208	-	-	-	50,208
Total contractual obligations	**$ 1,062,852**	**$ 1,012,644**	**$ -**	**$ -**	**$ 50,208**

Secured Notes Payable
On August 31, 2010 we issued a US$175,000, 5% per annum secured promissory note to Source Re Work Program, Inc. ("Source"). The note was secured by Eagleford's interest in the Matthews Lease, Zavala County, Texas. US$100,000 of the note was due on February 28, 2011 and was repaid. The balance of US$75,000 (CDN $73,380) of the note together with accrued interest is due and payable on August 31, 2011. For the year ended August 31, 2011 interest of $6,115 was recorded and included in accounts payable. On September 1, 2011 we repaid to Source, the secured promissory note in full in the amount of US$75,000 together with accrued interest of US$6,250

At August 31, 2011 we have a US$960,000 (2011 CDN $939,264), 6% per annum secured promissory note payable to Benchmark Enterprises LLC (August 31, 2010 US960,000). The note was payable on the earlier of December 31, 2011 or upon us closing a financing or series of financings in excess of US$4,500,000. The note has been extended until June 30, 2012 with an interest rate of 10% per annum. For the year ended August 31, 2011 interest of $56,356 was recorded and included in accounts payable (August 31, 2010 $26,863). The note is secured by Dyami Energy's interest in the Matthews and Murphy Leases, Zavala County, Texas. We may, in its sole discretion, repay any portion of the principal amount. In addition to the contractual financial obligations noted above we have development commitments on our Mathews Lease and Murphy Lease in order to keep the leases in good standing.

Mathews Lease, Zavala County, Texas, USA
On June 14, 2010, Eagleford acquired a 10% working interest before payout and a 7.5% working interest after payout of production revenue of $15 million in a mineral lease comprising approximately 2,629 gross acres of land in Zavala County, Texas for consideration of $212,780.

On August 31, 2010 we acquired all of the issued and outstanding membership interests of Dyami Energy, an exploration stage company. Dyami Energy holds a 75% working interest before payout and a 61.50% working interest after payout of production revenue of $12.5 million in the Matthews Lease, subject to the San Miguel formation farmout agreement noted below.

The royalties payable under the Matthews Lease are 25%.

Dyami Energy acquired its interest in the Matthews Lease through a Purchase and Sale Agreement dated February 8, 2010 and amended October 15, 2010 (the “Agreement”). Under the terms of the Agreement, Dyami Energy had the following commitments:

(a) On or before August 23, 2010 Dyami Energy shall commence operations to drill an Initial Test Well on Matthews Lease to a depth of not less than 3,000 feet below the surface or to the base of the San Miguel “D” formation;
(b) On or before July 8, 2011, Dyami Energy shall commence operations to perform an injection operation (by use of steam, nitrogen or other) in the San Miguel formation on the Initial Test Well or any other well located on the Matthews Lease; and
(c) On or before January 1, 2011, Dyami Energy shall commence a horizontal well to test the Eagle Ford shale formation with a projected lateral length of not less than 2,500 feet (the “Second Test Well”).

Dyami Energy’s 15% working interest partner has an obligation to participate in each of the operations provided for in (a), (b) and (c) above and if the partner fails to bear its share of the costs of such operations, the partner shall forfeit its interest in and to the well and the applicable spacing unit.

In August 2010, Dyami Energy commenced operations to drill its Matthews/Dyami #1-H well to a measured depth of 8,563 feet including 3,300 horizontal feet into the Eagle Ford shale formation and accordingly Dyami Energy satisfied (a) and (c) above. The well has been logged and cored and we are formulating a detailed frac design and completion plan.

In order to satisfy (b) above on March 29, 2011 we spud the Matthews/Dyami #3 well and drilled to a vertical depth of approximately 3,500 feet to the base of the San Miguel formation. We completed a nitrified acid injection operation and the well has been placed on production testing.

On March 31, 2011 we entered into a Farmout Agreement (the “Farmout”) from surface to the base of the San Miguel formation (the “San Miguel”) on the Matthews Lease. Under the Farmout, the farmee may spend up to US$1,050,000 on exploration and development of the San Miguel to earn a maximum of 42.50% working interest (31.875% net revenue interest). Under the terms of the Farmout, the farmee may earn an initial 25% of our working interest in the San Miguel by paying 100% of the costs to drill, complete, equip and perform an injection operation on a vertical test well to a depth of approximately 3,500 feet (the “Initial Test Well”). After the performance of the Initial Test Well, the farmee may increase its working interest to 50% of our working interest by spending the entire $1,050,000 on additional operations on the San Miguel in a good faith effort to produce hydrocarbons. During the year ended August 31, 2011, the Company incurred $744,837 in costs related to the Matthews/Dyami #3 well and $71,871 is included in accounts receivable. As of August 31, 2011 and the date of this Annual Report we had not assigned any interest to the farmee in the San Miguel formation.

Dyami Energy is the designated operator under the provisions of the Matthews Lease Operating Agreement.

The Matthews Oil and Gas Lease has a primary term of three years commencing April 12, 2008 and is now being held under a continuous drilling program provision which requires a well to be drilled every 180 days. Upon cessation of timely drilling, rights for further drilling expire on all acreage not included in a production unit which shall be re-assigned.

Subsequent to the year ended August 31, 2011, we commenced drilling its Matthews/Dyami #2H well located in Zavala County, Texas.

G. SAFE HARBOR

Certain statements in Sections 5.E and 5.F of this Annual Report may constitute "forward looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Such statements are generally identifiable by the terminology used such as "plans", "expects", "estimates", "budgets", "intends", "anticipates", "believes", "projects", "indicates", "targets", "objective", "could", "may", or other similar words. The forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Readers should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated.

ITEM 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

A. DIRECTORS AND SENIOR MANAGEMENT

The following table sets forth the names of all of our directors and executive officers as of the date of the filing of this Annual Report, with each position and office held by them in our Company, and the period of their service as a director or as an officer.

Name	Age	Position with the Company	Date First Elected as Director
James Cassina	55	President, Chief Executive Officer, Chief Financial Officer and Director	February 9, 2010
Milton Klyman	86	Director	November 15, 1996
Colin McNeil	65	Director	June 18, 2010
Alan D. Gaines	56	Director	January 25, 2012

All of our directors serve until our next Annual General Meeting or until a successor is duly elected, unless the office is vacated in accordance with our Articles or Bylaws. Subject to the terms of their employment agreements, if any, executive officers are appointed by the Board of Directors to serve until the earlier of their resignation or removal, with or without cause by the directors. James Cassina, our sole executive officer, devotes approximately 40% of his work time to his duties as an officer and director.

There are no family relationships between any of our directors or executive officers. There are no arrangements or understandings between any two or more directors or executive officers.

Mr. Cassina has been an officer since June 18, 2010 a director of ours since February 9, 2010. Mr. Cassina is an officer of Dyami Energy LLC our Texas subsidiary. As Chairman of Assure Energy, Inc. (“Assure”) (OTCBB: ASUR), an oil and gas exploration and production company, Mr. Cassina led Assure’s merger in September 2005 with Geocan Energy Inc. (TSX: GCA) (“Geocan”), an oil and gas company which then grew to daily production of over 3,700 barrels of oil or gas equivalents. Mr. Cassina thereafter served as a Director of Geocan and later Chairperson of its Board appointed Special Advisory Committee formed to seek strategic alternatives to enhance shareholder value. Subsequently Geocan merged with Arsenal Energy Inc. in October 2008. Mr. Cassina served in various senior capacities, including President, and Director from 1999 to 2002 and then Chairman until March 2007 of EnerNorth Industries Inc. (AMEX: ENY), an international enterprise engaged in engineering and offshore fabrication, oil and gas exploration and production, and in India, independent power project development.

Mr. Milton Klyman has been a director of ours since November 15, 1996. Mr. Klyman was also our Treasurer from December 31, 2003 to December 28, 2007. From February 27, 2009 to present, Mr. Klyman has been a director of 1354166 Alberta Ltd., our Alberta subsidiary. Mr. Klyman is a self-employed financial consultant and has been a Chartered Accountant since 1952. Mr. Klyman is a Life Member of the Canadian Institute of Chartered Accountants. Mr. Klyman serves as a director on the board of Western Troy Capital Resources Inc Mr. Klyman served as a director of the EnerNorth from April 2001 until March 21, 2007.

On March 20, 2007 EnerNorth filed an Assignment in Bankruptcy under the Bankruptcy and Insolvency Act (Canada).

Mr. Colin McNeil, has been a director of ours since June 18, 2010. Mr. McNeil is a self-employed oil and gas consultant and has been a geophysicist since 1972. Mr. McNeil serves as a director of Strategic Oil & Gas. Mr. McNeil has managed exploration programs and structured technical assessments for companies in the Middle East, Africa, Asia, Central and South America, the Arctic, and Canada.Mr. McNeil is a member of the Association of Professional, Engineers, Geologists and Geophysicists of Alberta, Society of Exploration Geophysicists, Canadian Society of Exploration Geophysicists, American Association of Petroleum Geologists and the Canadian Society of Petroleum Geologists.

Mr. Alan D. Gaines, B.B.A, M.B.A was appointed to the Board of Directors of Eagleford Energy On January 25, 2012. Mr. Gaines has approximately 30 years experience as an energy investment and merchant banker, and has participated in raising significant debt and equity during his career. The notable experience of Mr. Gaines extends to operations as well. Mr. Gaines founded and served as CEO of Dune Energy from inception in May 2001 through May 2007. In May 2007, Dune Energy completed the acquisition of Goldking Energy Corporation for $327 million, raising total proceeds of $540 million in senior notes and convertible preferred stock, as well as refinancing existing indebtedness in conjunction with the acquisition. Concurrent with the closing of the Goldking transaction, new operating management, including a new CEO, was hired by Dune Energy to oversee day to day operations. Mr. Gaines retained his title of Chairman of the Board.

B. COMPENSATION

Executive Compensation

The following table presents a summary of all annual and long-term compensation paid or accrued by us including our subsidiaries, for services rendered to us by our executive officers and directors in any capacity for the year ended August 31, 2011.

Summary Compensation Table (CDN$)

					Non-equity Incentive Plan Compensation				
Name and Principal Position	**Year**	**Salary (1) ($)**	**Share Based Awards ($)**	**Option Based Awards (2) ($)**	**Annual Incentive Plans ($)**	**Long Term Incentive Plans ($)**	**Pension Value ($)**	**All Other Compen-sation (3) ($)**	**Total Compen-sation ($)**
James Cassina, Chief Executive Officer, President and Director (4)	2011	$ 56,250	0	0	0	0	0	700	$ 56,950
Milton Klyman, Director	2011	0	0	0	0	0	0	700	$ 700
Colin McNeil, Director	2011	0	0	0	0	0	0	700	$ 700
Eric Johnson (4) Vice President of Operations for Dyami Energy LLC	2011	$ 43,750	0	0	0	0	0	0	$ 43,750

(1) Salaries /Management fees.
(2) No options have been issued to date.
(3) Accrued on account of directors fees at a rate of $100 per meeting.
(4) Mr. Johnson was our Vice President of Operations of Dyami Energy LLC from August 31, 2010 until April 13, 2011.

Compensation Discussion and Analysis

Objective of the Compensation Program

The objectives of the Company's compensation program are to attract, hold and inspire performance of its named executive officers (“NEOs”) of a quality and nature that will enhance the sustainable profitability and growth of the Company. The Company views it as an important objective of the Company's compensation program to ensure staff retention.

The Compensation Review Process

To determine compensation payable, the compensation committee of the Company (the " **Compensation Committee** ") determines an appropriate compensation reflecting the need to provide incentive and compensation for the time and effort expended by the NEOs of the Company while taking into account the financial and other resources of the Company.

The Company's Compensation Committee is comprised of Milton Klyman (Chair) and Colin McNeil. The Compensation Committee is comprised entirely of independent directors. Compensation is determined in the context of our strategic plan, our growth, shareholder returns and other achievements and considered in the context of position descriptions, goals and the performance of each NEO. With respect to directors' compensation, the Compensation Committee reviews the level and form of compensation received by the directors, members of each committee, the board chair and the chair of each board committee, considering the duties and responsibilities of each director, his or her past service and continuing duties in service to us. The compensation of directors, the CEO and executive officers of competitors are considered, to the extent publicly available, in determining compensation and the Compensation Committee has the power to engage a compensation consultant or advisor to assist in determining appropriate compensation.

Elements of Executive Compensation

The Company's NEO compensation program is based on the objectives of: (a) recruiting and retaining the executives critical to the success of the Company; (b) providing fair and competitive compensation; (c) balancing the interests of management and shareholders of the Company; and (d) rewarding performance, on the basis of both individual and corporate performance.

For the financial year ended August 31, 2011, the Company's NEO compensation program consisted of the following elements:

(a) a management fee (the " **Short-Term Incentive** ").

(b) a long-term equity compensation consisting of stock options granted under the Company's stock incentive plan (**"Long-Term Incentive"**).

The specific rationale and design of each of these elements are outlined in detail below.

Short-Term Incentive

Salaries form an essential element of the Company's compensation mix as they are the first base measure to compare and remain competitive relative to peer groups. Base salaries are fixed and therefore not subject to uncertainty and are used as the base to determine other elements of compensation and benefits. The base salary provides an immediate cash incentive for the Named Executive Officers. The Compensation Committee and the Board review salaries at least annually.

Base salary/management fees of the Named Executive Officer is set by the Compensation Committee on the basis of the applicable officer's responsibilities, experience and past performance. In determining the base salary to be paid to a particular Named Executive Officer, the Compensation Committee considers the particular responsibilities related to the position, the experience level of the officer, and his or her past performance at the Company and the current financial position of the Company.

Long-Term Incentive

The granting of stock options is a variable component of compensation intended to reward the Company's Named Executive Officers for their success in achieving sustained, long-term profitability and increases in stock value. Stock options ensure that the Named Executive Officers are motivated to achieve long-term growth of the Company and continuing increases in shareholder value. In terms of relative emphasis, the Company places more importance on stock options.

The Company provides long-term incentive compensation through its stock option plan. The Compensation Committee recommends the granting of stock options from time to time based on its assessment of the appropriateness of doing so in light of the long-term strategic objectives of the Company, its current stage of development, the need to retain or attract particular key personnel, the number of stock options already outstanding and overall market conditions. The Compensation Committee views the granting of stock options as a means of promoting the success of the Company and higher returns to its shareholders. The Board grants stock options after reviewing recommendations made by the Compensation Committee.

As of our fiscal year end August 31, 2011 we had no option/stock appreciation rights or grants outstanding.

Stock Option Plan

The Company's Stock Option Plan (the "Plan") was adopted by the board of directors on December 21, 2010 and approved by a majority of our shareholders voting at the Annual and Special Meeting held on February 24, 2011. The Plan was adopted in order that we may be able to provide incentives for directors, officers, employees, consultants and other persons (an "Eligible Individual") to participate in our growth and development by providing us with the opportunity through share options to acquire an ownership interest in us. Directors and officers currently are not remunerated for their services except as stated in "Executive Compensation" above.

The maximum number of common shares which may be set aside for issue under the Plan is currently 6,170,205 common shares, provided that the board has the right, from time to time, to increase such number subject to the approval of our shareholders and any relevant stock exchange or other regulatory authority. The maximum number of common shares which may be reserved for issuance to any one person under the plan is 5% of the common shares outstanding at the time of the grant less the number of shares reserved for issuance to such person under any options for services or any other stock option plans. Any common shares subject to an option, which are not exercised, will be available for subsequent grant under the Plan. The option price of any common shares cannot be less than the closing sale price of such shares quoted on any trading system or on such stock exchange in Canada on which the common shares are listed and posted for trading as may be selected for such purpose by the board of directors, on the day immediately preceding the day upon which the grant of the option is approved by the board of directors.

Options granted under the Plan may be exercised during a period no exceeding five years, subject to earlier termination upon the optionee ceasing to be an Eligible Individual, or, in accordance with the terms of the grant of the option. The options are non-transferable and non-assignable except between an Eligible Individual and a related corporation controlled by such Eligible Individual upon the consent of the board of directors. The Plan contains provisions for adjustment in the number of shares issuable there under in the event of subdivision, consolidation, reclassification, reorganization or change in the number of common shares, a merger or other relevant change in the Company's capitalization. The board of directors may from time to time amend or revise the terms of the Plan or may terminate the Plan at any time. At the Annual and Special Meeting of Shareholders to be held on February 24, 2012, the Company is seeking shareholder approval to amend the Plan to increase the maximum aggregate number of common shares reserved for issuance under our stock option plan, as amended, (the "Plan") to an amount not to exceed 20% of the total shares issued and outstanding of the Company as of the date of each Option grant.The Company does not have any other long-term incentive plans, including any supplemental executive retirement plans.

Overview of How the Compensation Program Fits with Compensation Goals

The compensation package is designed to meet the goal of attracting, holding and motivating key talent in a highly competitive oil and gas exploration environment through salary and providing an opportunity to participate in the Company's growth through stock options. Through the grant of stock options, if the price of the Company shares increases over time, both the Named Executive Officer and shareholders will benefit.

Incentive Plan Awards

There are no incentive plan awards outstanding for any of the Named Executive Officers as of August 31, 2011.

Pension Plan Benefits

The Company does not currently provide pension plan benefits to its Named Executive Officers.

Termination and Change of Control Benefits

The Company does not currently have executive employment agreements in place with any of its Named Executive Officers.

The Company has no compensatory plan, contract or arrangement where a named executive officer or director is entitled to receive compensation in the event of resignation, retirement, termination, change of control or a change in responsibilities following a change in control.

Director Compensation

Each director of the Company is entitled to receive the sum of $100 for each meeting of the directors, meeting of a committee of the directors or meeting of the shareholders attended. During the fiscal year ended August 31, 2011 no amount was paid by the Company with respect to such fees.

Retirement Policy for Directors

The Company does not have a retirement policy for its directors.

Directors' and Officers' Liability Insurance

The Company does not maintain directors' and officers' liability insurance.

C. BOARD PRACTICES

Board of Directors

The mandate of our board of directors, prescribed by the Business Corporations Act (Ontario), is to manage or supervise the management of our business and affairs and to act with a view to our best interests. In doing so, the board oversees the management of our affairs directly and through its committees.

The term of Mr. Klyman as a director began on August 10, 2000. Mr. Cassina was appointed as a director on February 9, 2010, Mr. McNeil who was appointed on June 18, 2010 and Mr. Gaines was appointed as a director on January 25, 2012. Our directors serve until our next Annual General Meeting or until a successor is duly elected, unless the office is vacated in accordance with our Articles or Bylaws. Our sole executive officer was appointed by our Board of Directors to serve until the earlier of his resignation or removal, with or without cause by the directors. There was no compensation paid by us to our directors during the fiscal year ended August 31, 2011 for their services in their capacity as directors or any compensation paid to committee members.

As of the date of this Annual Report our board of directors consists of four directors, three of which are "independent directors" in that they are "independent from management and free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the directors ability to act with a view to our best interests, other than interests and relationships arising from shareholding". The independent directors are Milton Klyman, Colin McNeil and Mr. Gaines. It is our practice to attempt to maintain a diversity of professional and personal experience among our directors.

The independent directors of the Company do not hold regularly scheduled meetings at which non-independent directors and members of management are not in attendance. The Company holds meetings as required, at which the opinions of the independent directors are sought and duly acted upon for all material matters relating to the Company.

Directorships

The following directors of ours are directors of other Canadian or United States reporting issuers as follows:

Colin McNeil	Strategic Oil & Gas Ltd.
Milton Klyman	Western Troy Capital Resources Inc.
Alan D. Gaines	Signature Exploration Corp.

Board and Committee Meetings

The board of directors has met at least once annually or otherwise as circumstances warrant to review our business operations, corporate governance and financial results. The table below reflects the attendance of each director of ours at each Board and committee meeting of the Board during the fiscal year ended August 31, 2011.

Name	Board of Directors Meetings	Audit Committee Meetings	Compensation Committee Meetings	Petroleum and Natural Gas Committee Meetings	Disclosure Committee Meetings
Milton Klyman	4	4	Nil	1	Nil
James Cassina	4	4	Nil	1	Nil
Colin McNeil	4	4	Nil	1	Nil

Board Mandate

The Board assumes responsibility for stewardship of the Company, including overseeing all of the operation of the business, supervising management and setting milestones for the Company. The Board reviews the statements of responsibilities for the Company including, but not limited to, the code of ethics and expectations for business conduct.

The Board approves all significant decisions that affect the Company and its subsidiaries and sets specific milestones towards which management directs their efforts.

The Board ensures, at least annually, that there are long-term goals and a strategic planning process in place for the Company and participates with management directly or through its committees in developing and approving the mission of the business of the Company and the strategic plan by which it proposes to achieve its goals, which strategic plan takes into account, among other things, the opportunities and risks of the Company's business. The strategic planning process is carried out at each Board meeting where there are regularly reviewed specific milestones for the Company.

The strategic planning process incorporates identifying the main risks to the Company's objectives and ensuring that mitigation plans are in place to manage and minimize these risks. The Board also takes responsibility for identifying the principal risks of the Company's business and for ensuring these risks are effectively monitored and mitigated to the extent practicable. The Board appoints senior management.

The Company adheres to regulatory requirements with respect to the timeliness and content of its disclosure. The Board approves all of the Company's major communications, including annual and quarterly reports and press releases. The Chief Executive Officer authorizes the issuance of news releases. The Chief Executive Officer is generally the only individual authorized to communicate with analysts, the news media and investors about information concerning the Company.

The Board and the audit committee of the Company (the **"Audit Committee"**) examines the effectiveness of the Company's internal control processes and information systems.

The Board as a whole, given its small size, is involved in developing the Company's approach to corporate governance. The number of scheduled board meetings varies with circumstances. In addition, special meetings are called as necessary. The Chief Executive Officer establishes the agenda at each Board meeting and submits a draft to each director for their review and recommendation for items for inclusion on the agenda. Each director has the ability to raise subjects that are not on the agenda at any board meeting. Meeting agendas and other materials to be reviewed and/or discussed for action by the Board are distributed to directors in time for review prior to each meeting. Board members have full and free access to senior management and employees of the Company.

Position Descriptions

The Board has not developed written position descriptions for the Chairman of the Board or the Chief Executive Officer. The Board is currently of the view that the respective corporate governance roles of the Board and management, as represented by the Chief Executive Officer, are clear and that the limits to management's responsibility and authority are well-defined.

Each of the Audit Committee, Compensation Committee, Disclosure Committee and a Petroleum and Natural Gas Committee has a chair and a mandate.

Orientation and Continuing Education

We have developed an orientation program for new directors including a director’s manual ("Director’s Manual") which contains information regarding the roles and responsibilities of the board, each board committee, the board chair, the chair of each board committee and our president. The Director’s Manual contains information regarding its organizational structure, governance policies including the Board Mandate and each Board committee charter, and our code of business conduct and ethics. The Director’s Manual is updated as our business, governance documents and policies change. We update and inform the board regarding corporate developments and changes in legal, regulatory and industry requirements affecting us.

Ethical Business Conduct

We have adopted a written code of business conduct and ethics (the " **Code** ") for our directors, officers and employees. The board encourages following the Code by making it widely available. It is distributed to directors in the Director’s Manual and to officers, employees and consultants at the commencement of their employment or consultancy. The Code reminds those engaged in service to us that they are required to report perceived or actual violations of the law, violations of our policies, dangers to health, safety and the environment, risks to our property, and accounting or auditing irregularities to the chair of the Audit Committee who is an independent director of ours. In addition, to requiring directors, officers and employees to abide by the Code, we encourage consultants, service providers and all parties who engage in business with us to contact the chair of the Audit Committee regarding any perceived and all actual breaches by our directors, officers and employees of the Code. The chair of our Audit Committee is responsible for investigating complaints, presenting complaints to the applicable board committee or the board as a whole, and developing a plan for promptly and fairly resolving complaints. Upon conclusion of the investigation and resolution of a complaint, the chair of our Audit Committee will advise the complainant of the corrective action measures that have been taken or advise the complainant that the complaint has not been substantiated. The Code prohibits retaliation by us, our directors and management, against complainants who raise concerns in good faith and requires us to maintain the confidentiality of complainants to the greatest extent practical. Complainants may also submit their concerns anonymously in writing. In addition to the Code, we have an Audit Committee Charter and a Policy of Procedures for Disclosure Concerning Financial/Accounting Irregularities.

Since the beginning of our most recently completed financial year, no material change reports have been filed that pertain to any conduct of a director or executive officer that constitutes a departure from the Code. The board encourages and promotes a culture of ethical business conduct by appointing directors who demonstrate integrity and high ethical standards in their business dealings and personal affairs. Directors are required to abide by the Code and expected to make responsible and ethical decisions in discharging their duties, thereby setting an example of the standard to which management and employees should adhere. The board is required by the Board Mandate to satisfy our CEO and other executive officers are acting with integrity and fostering a culture of integrity throughout the Company. The board is responsible for reviewing departures from the Code, reviewing and either providing or denying waivers from the Code, and disclosing any waivers that are granted in accordance with applicable law. In addition, the board is responsible for responding to potential conflict of interest situations, particularly with respect to considering existing or proposed transactions and agreements in respect of which directors or executive officers advise they have a material interest. The Board Mandate requires that directors and executive officers disclose any interest and the extent, no matter how small, of their interest in any transaction or agreement with us, and that directors excuse themselves from both board deliberations and voting in respect of transactions in which they have an interest. By taking these steps the board strives to ensure that directors exercise independent judgment, unclouded by the relationships of the directors and executive officers to each other and us, in considering transactions and agreements in respect of which directors and executive officers have an interest.

Nomination of Directors

The Board has not appointed a nominating committee and does not believe that such a committee is warranted at the present time. The entire Board determines new nominees to the Board, although a formal process has not been adopted. The nominees are generally the result of recruitment efforts by the Board members, including both formal and informal discussions among Board members and officers. The Board generally looks for the nominee to have direct experience in the oil and gas business and significant public company experience. The nominee must not have a significant conflicting public company association.

Compensation

The Board determines director and executive officer compensation by recommendation of the Compensation Committee. The Company's Compensation Committee reviews the amounts and effectiveness of compensation. Each of the members of the Compensation Committee are independent. The Board reviews the adequacy and form of compensation and compares it to other companies of similar size and stage of development. There is no minimum share ownership requirement of directors.

The Compensation Committee convenes at least once annually to review director and officer compensation and status of stock options. The Compensation Committee also responds to requests from management and the Board to review recommendations of management for new senior employees and their compensation. The Compensation Committee has the power to approve and/or amend these recommendations.

The Company has felt no need to retain any compensation consultants or advisors at any time since the beginning of the Company's most recently completed financial year.

Committees of the Board

Our board of directors discharges its responsibilities directly and through committees of the board of directors, currently consisting of the Audit Committee, a compensation committee (the " **Compensation Committee** "), a disclosure committee (the " **Disclosure Committee** ") and a petroleum and natural gas committee (the " **Petroleum and Natural Gas Committee** ").

Each of the Audit Committee, Disclosure Committee and the Petroleum and Natural Gas Committee consists of a majority of independent directors, while the Compensation Committee consists of independent directors. Each Committee has a specific mandate and responsibilities, as reflected in the charters for each committee.

Audit Committee

The mandate of the Audit Committee is formalized in a written charter. The members of the Audit Committee are James Cassina, Milton Klyman (Chair) and Colin McNeil. Based on his professional certification and experience, the board has determined that Milton Klyman is an Audit Committee Financial Expert and that James Cassina and Colin McNeil are financially literate. The Audit Committee's primary duties and responsibilities are to serve as an independent and objective party to monitor our financial reporting process and control systems, review and appraise the audit activities of our independent auditors, financial and senior management, and the lines of communication among the independent auditors, financial and senior management, and the board of directors for financial reporting and control matters including investigating fraud, illegal acts or conflicts of interest.

Compensation Committee

The mandate of the Compensation Committee is formalized in a written charter. The members of the Compensation Committee are Colin McNeil and Milton Klyman (Chair). The Compensation Committee is comprised entirely of independent directors. Compensation is determined in the context of our strategic plan, our growth, shareholder returns and other achievements and considered in the context of position descriptions, goals and the performance of each individual director and officer. With respect to directors' compensation, the Compensation Committee reviews the level and form of compensation received by the directors, members of each committee, the board chair and the chair of each board committee, considering the duties and responsibilities of each director, his or her past service and continuing duties in service to us. The compensation of directors, the CEO, CFO and executive officers of competitors are considered, to the extent publicly available, in determining compensation and the Compensation Committee has the power to engage a compensation consultant or advisor to assist in determining appropriate compensation.

Disclosure Committee

The mandate of the Disclosure Committee is formalized in a written charter. The members of the Disclosure Committee are Milton Klyman, Colin McNeil and James Cassina (Chair). The Committee's duties and responsibilities include, but are not limited to, review and revise our controls and other procedures ("Disclosure and Controls Procedures") to ensure that (i) information required by us to be disclosed to the applicable regulatory authorities and other written information that we will disclose to the public is reported accurately and on a timely basis, and (ii) such information is accumulated and communicated to management, as appropriate to allow timely decisions regarding required disclosure; assist in documenting and monitoring the integrity and evaluating the effectiveness of the Disclosure and Control Procedures; the identification and disclosure of material information about us, the accuracy completeness and timeliness of our financial reports and all communications with the investing public are timely, factual and accurate and are conducted in accordance with applicable legal and regulatory requirements.

Petroleum and Natural Gas Committee

The members of the Petroleum and Natural Gas Committee are Milton Klyman, James Cassina and Colin McNeil (Chair). The Petroleum and Natural Gas Committee has the responsibility of meeting with the independent engineering firms commissioned to conduct the reserves evaluation on our oil and natural gas assets and to discuss the results of such evaluation with each of the independent engineers and management. Specifically, the Petroleum and Natural Gas Committee's responsibilities include, but are not limited to, a review of management's recommendations for the appointment of independent engineers, review of the independent engineering reports and considering the principal assumptions upon which such reports are based, appraisal of the expertise of the independent engineering firms retained to evaluate our reserves, review of the scope and methodology of the independent engineers' evaluations, reviewing any problems experienced by the independent engineers in preparing the reserve evaluation, including any restrictions imposed by management or significant issues on which there was a disagreement with management and a review of reserve additions and revisions which occur from one report to the next.

Assessments

The board assesses, on an annual basis, the contributions of the board as a whole, the Audit Committee and each of the individual directors, in order to determine whether each is functioning effectively. The board monitors the adequacy of information given to directors, communication between the board and management and the strategic direction and processes of the board and committees. The Audit Committee will annually review the Audit Committee Charter and recommend, if any, revisions to the board as necessary.

Audit Committee

The mandate of the Audit Committee is formalized in a written charter. The members of the audit committee of the board are James Cassina, Milton Klyman (Chairman) and Colin McNeil. Based on his professional certification and experience, the board has determined that Milton Klyman is an Audit Committee Financial Expert and that Colin McNeil and James Cassina are financially literate. The audit committee's primary duties and responsibilities are to serve as an independent and objective party to monitor our financial reporting process and control systems, review and appraise the audit activities of our independent auditors, financial and senior management, and the lines of communication among the independent auditors, financial and senior management, and the board of directors for financial reporting and control matters including investigating fraud, illegal acts or conflicts of interest.

Relevant Education and Experience of Audit Committee Members

Milton Klyman is the Chairman of the Audit Committee. He is a self-employed financial consultant and has been a Chartered Accountant since 1952. Milton Klyman is a Life Member of the Institute of Chartered Accountants of Ontario, a Life member of the Canadian Institute of Mining Metallurgy and Petroleum and a Fellow of the Institute of Chartered Secretaries and Administrators.

James Cassina is a consultant in business development, mergers and acquisitions and corporate finance. James Cassina has served as a director and held various executive positions with public companies.

Colin McNeil is an independent consulting geophysicist and has managed exploration programs and structured technical assessments for companies in the Middle East, Africa, Asia, Central and South America, the Arctic, and Canada Colin McNeil has served as a director and held various positions with public and private companies.

Audit Committee Charter

- Our Audit Committee Charter (the "Charter") has been adopted by our board of directors. The Audit Committee of the board (the "Committee") will review and reassess this charter annually and recommend any proposed changes to the board for approval. The Audit Committee's primary duties and responsibilities are to:

- Oversee (i) the integrity of our financial statements; (ii) our compliance with legal and regulatory requirements; and (iii) the independent auditors' qualifications and independence.

- Serve as an independent and objective party to monitor our financial reporting processes and internal control systems.

- Review and appraise the audit activities of our independent auditors and the internal auditing functions.

- Provide open lines of communication among the independent auditors, financial and senior management, and the board for financial reporting and control matters.

Role and Independence: Organization

The Committee assists the board on fulfilling its responsibility for oversight of the quality and integrity of our accounting, auditing, internal control and financial reporting practices. It may also have such other duties as may from time to time be assigned to it by the board.

The Audit Committee is to be comprised of at least three directors. The majority of the Committee members must be independent from management and free from any relationship that, in the opinion of the Board, would interfere with the exercise of his or her independent judgment as a member of the Committee.

All members shall, to the satisfaction of the board, be financially literate (i.e. will have the ability to read and understand a balance sheet, an income statement, a cash flow statement and the notes attached thereto), and at least one member shall have accounting or related financial management expertise to qualify as "financially sophisticated". A person will qualify as "financially sophisticated" if an individual who possesses the following attributes:

- an understanding of financial statements and generally accepted accounting principles;

- an ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;

- experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by our financial statements, or experience actively supervising one or more persons engaged in such activities;

- an understanding of internal controls and procedures for financial reporting; and

- an understanding of audit committee functions.

Colin McNeil and Milton Klyman are "independent" as defined by the Securities and Exchange Commission, and the Board has determined that Milton Klyman is an "audit committee financial expert" as defined in Item 401(h) of Regulation S-K promulgated by the Securities and Exchange Commission.

The Committee members will be elected annually at the first meeting of the Board following the annual meeting of shareholders. Each member of the Committee serves during the pleasure of the Board and, in any event, only so long as he or she is a director.

One member of the Committee shall be appointed as chair. The chair shall be responsible for leadership of the Committee, including scheduling and presiding over meetings and making regular reports to the Board. The chair will also maintain regular liaison with the CEO, CFO, and the lead independent audit partner.

Responsibilities and Powers

Although the Committee may wish to consider other duties from time to time, the general recurring activities of the Committee in carrying out its oversight role are described below.

- Annual review and revision of the Charter as necessary with the approval of the board.
- Review and obtain from the independent auditors a formal written statement delineating all relationships between the auditor and us, consistent with Independence Standards Board Standard 1.
- Recommending to the board the independent auditors to be retained (or nominated for shareholder approval) to audit our financial statements. Such auditors are ultimately accountable to the board and the Committee, as representatives of the shareholders.
- Evaluating, together with the board and management, the performance of the independent auditors and, where appropriate, replacing such auditors.
- Obtaining annually from the independent auditors a formal written statement describing all relationships between the auditors and us. The Committee shall actively engage in a dialogue with the independent auditors with respect to any relationship that may impact the objectivity and the independence of the auditors and shall take, or recommend that the board take, appropriate actions to oversee and satisfy itself as to the auditors' independence.
- Ensuring that the independent auditors are prohibited from providing the following non-audit services and determining which other non-audit services the independent auditors are prohibited from providing:
    - Bookkeeping or other services related to our accounting records or consolidated financial statements;
    - Financial information systems design and implementation;
    - Appraisal or valuation services, fairness opinions, or contribution-in-kind reports;
    - Actuarial services;
    - Internal audit outsourcing services;
    - Management functions or human resources;
    - Broker or dealer, investment advisor or investment banking services;
    - Legal services and expert services unrelated to the audit; and
    - Any other services which the Public Company Accounting Oversight Board determines to be impermissible.
- Approving any permissible non-audit engagements of the independent auditors.
- Meeting with our auditors and management to review the scope of the proposed audit for the current year, and the audit procedures to be used, and to approve audit fees.
- Reviewing the audited consolidated financial statements and discussing them with management and the independent auditors. Consideration of the quality our accounting principles as applied in its financial reporting. Based on such review, the Committee shall make its recommendation to the Board as to the inclusion of our audited consolidated financial statement in our Annual Report to Shareholders.

- Discussing with management and the independent auditors the quality and adequacy of and compliance with our internal controls.

- Establishing procedures: (i) for receiving, handling and retaining of complaints received by us regarding accounting, internal controls, or auditing matters, and (ii) for employees to submit confidential anonymous concerns regarding questionable accounting or auditing matters.

- Review and discuss all related party transactions involving us.

- Engaging independent counsel and other advisors if the Committee determines that such advisors are necessary to assist the Committee in carrying out its duties.

- Publicly disclose the receipt of warning about any violations of corporate governance rules.

Authority

The Committee will have the authority to retain special legal, accounting or other experts for advice, consultation or special investigation. The Committee may request any officer or employee of ours, our outside legal counsel, or the independent auditor to attend a meeting of the Committee, or to meet with any member of, or consultants to, the Committee. The Committee will have full access to our books, records and facilities.

Meetings

The Committee shall meet at least yearly, or more frequently as the Committee considers necessary. Opportunities should be afforded periodically to the external auditor and to senior management to meet separately with the independent members of the Committee. Meetings may be with representatives of the independent auditors, and appropriate members of management, all either individually or collectively as may be required by the Chairman of the Committee.

The independent auditors will have direct access to the Committee at their own initiative.

The Chairman of the Committee will report periodically the Committee's findings and recommendations to the board of directors.

D. EMPLOYEES

As of August 31, 2011 and the date of the filing of this Annual Report we did not have any employees other than our sole executive officer.

E. SHARE OWNERSHIP

Our common shares are owned by Canadian residents, United States residents and residents of other countries. The only class of our securities, which is outstanding as of the date of the filing of this Annual Report, is common stock. All holders of our common stock have the same voting rights with respect to their ownership of our common stock.

The following table sets forth as of the date of the filing of this Annual Report, certain information with respect to the amount and nature of beneficial ownership of the common stock held by (i) each person known to our management to be the beneficial owner of more than 5% of our outstanding shares of common stock; (ii) each person who is a director or an executive officer of ours; and (iii) all directors and executive officers of ours, as a group. Shares of our common stock subject to options, warrants, or convertible securities currently exercisable or convertible or exercisable or convertible within 60 days of the date of filing of this Annual Report are deemed outstanding for computing the share ownership and percentage of the person holding such options, warrants, or convertible securities but are not deemed outstanding for computing the percentage of any other person.

Name and Owner	Identity	Amount and Nature of Beneficial Ownership of Common Stock (1)	Percentage
Alan D. Gaines	Director	4,000,000(10)	10.07%
Milton Klyman	Director	100,000(2)	0.26%
Colin McNeil	Director	0	0%
Core Energy Enterprise, Inc. (3)	Principal Shareholder	4,073,208(4)	10.25%
James Cassina	Director and Principal Shareholder	12,168,852(5)	29.17%
Tonbridge Financial Corp.	Principal Shareholder	5,483,414(6)	13.55%
Benchmark Enterprises LLC	Shareholder	2,258,824(7)	5.90%
Eric Johnson	Principal Shareholder	3,384,282(8)	8.71%
Gottbetter Capital Group, Inc.	Shareholder	2,416,881(9)	6.38%
All officers and directors as a group (4 persons)		16,268,852(2)(5)	32.52%

(1) Unless otherwise indicated, the persons named have sole ownership, voting and investment power with respect to their stock, subject to applicable laws relative to rights of spouses. Percentage ownership is based on 37,716,076 shares of common stock outstanding as of the date of filing of this Annual Report.

(2) Includes 50,000 shares underlying 50,000 presently exercisable warrants.

(3) James Cassina has voting and investment power with respect to the shares of our common stock owned by Core Energy Enterprises Inc.

(4) Includes 2,036,604 shares underlying 2,036,604 presently exercisable warrants.

(5) Includes 2,036,604 outstanding shares and 2,036,604 shares underlying 2,036,604 presently exercisable warrants owned by Core Energy Enterprises Inc. Also includes 4,099,725 shares underlying 3,995,919 presently exercisable warrants owned directly by James Cassina.

(6) Includes 2,741,707 shares underlying 2,741,707 presently exercisable warrants. David Yuhasz has voting and investment power with respect to the shares owned by Tonbridge Financial Corp.

(7) Includes 1,677,685 shares and 581,139 shares underlying presently exercisable warrants. 581,140 shares and 290,570 warrants are being held in escrow until such time that we receive a NI 51-101 compliant report from an independent engineering firm indicating at least 100,000 boe of proven reserves on either the Murphy Lease or any formation below the San Miguel formation on the Matthews Lease. Andrew Godfrey has voting and investment power with respect to the shares owned by Benchmark Enterprises LLC.

(8) Includes 2,256,188 shares and 1,128,094 shares underlying presently exercisable warrants. 1,128,094 shares and 564,047 warrants are being held in escrow until such time that we receive a NI 51-101 compliant report from an independent engineering firm indicating at least 100,000 boe of proven reserves on either the Murphy Lease or any formation below the San Miguel formation on the Matthews Lease.

(9) Includes 2,243,881 shares and 173,000 shares underlying presently exercisable warrants. Adam Gottbetter has voting and investment power with respect to the shares owned by Gottbetter Capital Group, Inc.

(10) Includes 2,000,000 outstanding shares and 2,000,000 presently exercisable warrants.

As of the date of the filing of this Annual Report, to the knowledge of our management, there are no arrangements which, could at a subsequent date result in a change in control of us. As of such date, and except as disclosed herein, our management has no knowledge that we are owned or controlled directly or indirectly by another company or any foreign government.

Amendments to our Stock Option Plan (as amended, the " **Plan** ") were adopted by our board of directors on December 21, 2010 and approved by a majority of our shareholders voting at the Annual and Special Meeting held on February 24, 2011. The Plan was adopted in order that we may be able to provide incentives for directors, officers, employees, consultants and other persons (an " **Eligible Individual** ") to participate in our growth and development by providing us with the opportunity through share options to acquire an ownership interest in us. Directors and officers currently are not remunerated for their services except as stated in " **Executive Compensation** " above.

The maximum number of common shares which may be set aside for issue under the Plan is currently 6,170,205 common shares, provided that the board has the right, from time to time, to increase such number subject to the approval of our shareholders and any relevant stock exchange or other regulatory authority. The maximum number of common shares which may be reserved for issuance to any one person under the plan is 5% of the common shares outstanding at the time of the grant less the number of shares reserved for issuance to such person under any options for services or any other stock option plans. Any common shares subject to an option, which are not exercised, will be available for subsequent grant under the Plan. The option price of any common shares cannot be less than the closing sale price of such shares quoted on any trading system or on such stock exchange in Canada on which the common shares are listed and posted for trading as may be selected for such purpose by the board of directors, on the day immediately preceding the day upon which the grant of the option is approved by the board of directors.

At our Annual and Special Meeting slated to be held on February 24, 2012 shareholders will be asked to approve a further amendment to our Plan which was adopted by our board of directors on January 25, 2012 to increase the maximum aggregate number of common shares reserved for issuance under our stock option plan to an amount not to exceed 20% of the total shares issued and outstanding of the Company as of the date of each Option grant. Options granted under the Plan may be exercised during a period not exceeding five years, subject to earlier termination upon the optionee ceasing to be an Eligible Individual, or, in accordance with the terms of the grant of the option. The options are non-transferable and non-assignable except between an Eligible Individual and a related corporation controlled by such Eligible Individual upon the consent of the board of directors. The Plan contains provisions for adjustment in the number of shares issuable there under in the event of subdivision, consolidation, reclassification, reorganization or change in the number of common shares, a merger or other relevant change in the Company's capitalization. The Company does not have any other long-term incentive plans, including any supplemental executive retirement plans.

ITEM 7 MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

A. MAJOR SHAREHOLDERS

There are 37,716,076 issued and outstanding shares of our common stock as of January 31, 2012. As of January 31, 2012, to the best of our knowledge, no persons hold directly or indirectly or exercise control or direction over, shares of our common stock carrying 5% or more of the voting rights attached to all issued and outstanding shares of the common stock except as stated under Item 6.E above or set out in the table below. The shares of our common stock owned by our major shareholders have identical voting rights as those owned by our other shareholders.

Name	Number of Shares	Percentage
James Cassina	12,168,852(1)	29.17%
Alan D. Gaines	4,000,000(8)	10.07%
Core Energy Enterprises Inc. (2)	4,073,208(3)	10.25%
Tonbridge Financial Corp.	5,483,414(4)	13.55%
Eric Johnson	3,384,282(5)	8.71%
Gottbetter Capital Group, Inc.	2,416,881(6)	6.83%
Benchmark Enterprises LLC	2,258,824(7)	5.90%

(1) Includes 2,036,604 shares and 2,036,604 shares underlying presently exercisable warrants owned by Core Energy Enterprises Inc. Also includes 4,099,725 shares and 3,995,919 shares underlying presently exercisable warrants owned directly by James Cassina.

(2) James Cassina has voting and investment power with respect to the shares of our common stock owned by Core Energy Enterprises Inc.

(3) Includes 2,036,604 shares and 2,036,604 shares underlying presently exercisable warrants.

(4) Includes 2,741,707 shares underlying 2,741,707 presently exercisable warrants. David Yuhasz has voting and investment power with respect to the shares owned by Tonbridge Financial Corp.

(5) Includes 2,256,188 shares and 1,128,094 shares underlying presently exercisable warrants. 1,128,094 shares and 564,047 warrants being held in escrow until such time that we receive a NI 51-101 compliant report from an independent engineering firm indicating at least 100,000 boe of proven reserves on either the Murphy Lease or any formation below the San Miguel formation on the Matthews Lease.

(6) Includes 2,243,881 shares and 173,000 shares underlying presently exercisable warrants. Adam Gottbetter has voting and investment power with respect to the shares owned by Gottbetter Capital Group, Inc.

(7) Includes 1,677,685 shares and 581,139 shares underlying presently exercisable warrants. 581,140 shares and 290,570 warrants being held in escrow until such time that we receive a NI 51-101 compliant report from an independent engineering firm indicating at least 100,000 boe of proven reserves on either the Murphy Lease or any formation below the San Miguel formation on the Matthews Lease. Andrew Godfrey has voting and investment power with respect to the shares owned by Benchmark Enterprises LLC.

(8) Includes 2,000,000 outstanding shares and 2,000,000 presently exercisable warrants.

The following table discloses the geographic distribution of the majority of the holders of record of our common stock as of date of January 31, 2012.

Country	Number of Shareholders	Number of Shares	Percentage of Shareholders	Percentage of Shares
Canada	1,073	15,055,803	95.63%	39.92%
USA	33	9,606,951	2.94%	25.47%
All Other	16	13,053,322	1.43%	34.61%
Total	1,122	37,716,076	100%	100%

We are not directly or indirectly owned or controlled by another corporation, by any foreign government or by any other natural or legal person. There are no arrangements known to us, the operation of which may at a subsequent date result in a change in the control of us.

B. RELATED PARTY TRANSACTIONS

During the fiscal year ended August 31, 2011 and through the date of the filing of this Annual Report, we have entered into the related party transactions described below.

At August 31, 2011 included in accounts payable are management fees payable to the President of $56,250 accrued at a rate of $6,250 per month.

During the year ended August 31, 2011, we received US$300,000 and issued a promissory note to our President. The note is due on demand and bears interest at 10% per annum. Interest is payable annually on the anniversary date of the note. For the year ended August 31, 2011 interest of $26,135 was recorded and included in accounts payable. Subsequent to the year-end we issued 103,806 common shares to our President as full settlement of interest due at October 7, 2011 in the amount of US$30,000.

At August 31, 2011 we accrued directors' fees payable of $2,100 at rate of $100 per meeting per director.

On August 31, 2010 we issued a US$175,000, 5% per annum secured promissory note to Source ReWork Program, Inc. ("Source"). The note was secured by the Eagleford's interest in the Matthews Lease, Zavala County, Texas. US$100,000 of the note was repaid on March 18, 2011. The balance of US$75,000 (CDN $73,380) of the note together with accrued interest was due and payable on August 31, 2011. For the year ended August 31, 2011 interest of $6,115 was recorded and included in accounts payable. On September 1, 2011 we repaid to Source Rework Program, Inc. the promissory note in full in the amount of US$75,000 together with accrued interest of US$6,250.

At August 31, 2011 the Company has a US$960,000 (2011 CDN $939,264), 6% per annum secured promissory note payable to Benchmark Enterprises LLC (August 31, 2010 US960,000). The note was payable on the earlier of December 31, 2011 or upon the Company closing a financing or series of financings in excess of US$4,500,000. The note has been extended until June 30, 2012 with an interest rate of 10% per annum. For the year ended August 31, 2011 interest of $56,356 was recorded and included in accounts payable (August 31, 2010 $26,863). The note is secured by Dyami Energy's interest in the Matthews and Murphy Leases, Zavala County, Texas. The Company may, in its sole discretion, repay any portion of the principal amount. On January 3, 2012 the Company issued 515,406 common shares as full settlement of interest due at December 31, 2011 in the amount of US$102,102.

On September 2, 2011 the Company received $20,000 and issued a promissory note to Tonbridge Financial Corp. The note is due on demand and bears interest at a rate of 10% per annum. Interest is payable annually on the anniversary date of the note.

At August 31, 2011 included in accounts payable is $68,918 due to Gottbetter & Partners LLP for legal fees (August 31, 2010 - $82,154). Gottbetter Capital Group, Inc. is a shareholder of the Company. Adam Gottbetter is sole owner of Gottbetter & Partners LLP and Gottbetter Capital Group, Inc.

During the year ended August 31, 2011, the Company received US$2,490,000 and $149,000 and issued promissory notes to seven shareholders. The notes are payable on demand and bear interest at 10% per annum. Interest is payable annually on the anniversary date of the notes. Subsequent to the year ended August 31, 2011 and to the date of this Annual Report the Company issued 639,297 common shares as full settlement of interest due in the amount of US$166,000 and CDN$14,900.

Subsequent to the year ended August 31, 2011 and to the date of this Annual Report the Company received $186,845 and US$165,000 and issued promissory notes to five shareholders of the Company. The notes are due on demand and bear interest at 10% per annum. Interest is payable annually on the anniversary date of the note.

Inter-Company Balances
As at August 31, 2011, the inter-company balance due from our wholly owned subsidiary 1354166 Alberta was $88,000. As at August 31, 2011, the inter-company balance due from our wholly owned subsidiary Dyami Energy was $3,782,893. As of January 31, 2011, the inter-company balance due from 1354166 Alberta is $88,000 and the inter-company balance due from Dyami Energy is $4,101,798.

C. INTERESTS OF EXPERTS AND COUNSEL

Not Applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

ITEM 8 FINANCIAL INFORMATION

A. CONSOLIDATED STATEMENTS AND OTHER FINANCIAL INFORMATION

The financial statements required as part of this Annual Report are filed under Item 17 of this Annual Report.

Litigation

Except as discussed below there are no pending legal proceedings to which we or our subsidiary is a party or of which any of our property is the subject. There are no legal proceedings to which any of the directors, officers or affiliates or any associate of any such directors, officers or affiliates of either our company or our subsidiary is a party or has a material interest adverse to us except for the following:

Subsequent to the year ended August 31, 2011, a vendor of Dyami Energy has filed a claim in the District Court of Harris County, Texas seeking payment of US$62,800. Dyami Energy is disputing the claim on the basis of excessive charges. The full amount of the claim has been recorded in accounts payable and the outcome of this claim is uncertain at this time.

Dividends

We have not paid any dividends on our common stock during the past five years. We do not intend to pay dividends on shares of common stock in the foreseeable future as we anticipate that our cash resources will be used to finance growth.

B. SIGNIFICANT CHANGES

There have been no significant changes that have occurred since the date of our annual financial statements included with this Annual Report except as disclosed in the Annual Report.

ITEM 9 THE OFFER AND LISTING

Common Shares

Our authorized capital consists of an unlimited number of common shares without par value, of which 37,716,076 were issued and outstanding as of January 31, 2012. All shares are initially issued in registered form. There are no restrictions on the transferability of our common shares imposed by our constating documents. Holders of our common shares are entitled to one vote for each common share held of record on all matters to be acted upon by our shareholders. Holders of common shares are entitled to receive such dividends as may be declared from time to time by our board of directors, in their discretion. In addition we are authorized to issue an unlimited number of preferred shares, with such rights, preferences and privileges as may be determined from time to time by our board of directors. There were no preferred shares outstanding at January 31, 2012.

Our common shares entitle their holders to: (i) vote at all meetings of our shareholders except meetings at which only holders of specified classes of shares are entitled to vote, having one vote per common share, (ii) receive dividends at the discretion of our board of directors; and (iii) receive our remaining property on liquidation, dissolution or winding up.

A. OFFER AND LISTING DETAILS

Our common stock became eligible for trading on October 22, 2009 on the Over the Counter Bulletin Board ("OTCBB") under the symbol ("EGNKF"). Following the amalgamation on November 30, 2009 with our wholly owned subsidiary 1406768 Ontario, we changed our name to Eagleford Energy Inc. and commenced trading under the symbol ("EFRDF"). Prior to our common stock being listed on the OTCBB, our common stock had not publicly traded since 1990.

The following table set forth the reported high and low bid prices for shares of our common stock on the OTCBB in US dollars for the periods indicated.

	Period (1)	**High**	**Low**
Fiscal Year August 31, 2011	Year Ended August 31, 2011	$ 2.03	$ 0.70
Fiscal Year August 31, 2010	Year Ended August 31, 2010	$ 1.30	$ 0.05
Fiscal Year 2011 By Quarter	First Quarter ended 11/30/2010	$ 2.03	$ 0.80
	Second Quartered Ended 02/28/2011	$ 2.00	$ 1.00
	Third Quartered Ended 05/31/2011	$ 1.24	$ 0.84
	Fourth Quartered Ended 08/31/2011	$ 1.75	$ 0.70
Fiscal Year 2010 By Quarter	First Quarter ended 11/30/2009	$ 0.00	$ 0.00
	Second Quartered Ended 02/28/2010	$ 0.05	$ 0.05
	Third Quartered Ended 05/31/2010	$ 0.00	$ 0.00
	Fourth Quartered Ended 08/31/2010	$ 1.30	$ 0.73
Calendar Year 2011 by Month	August	$ 1.18	$ 0.70
	September	$ 0.70	$ 0.30
	October	$ 0.48	$ 0.23
	November	$ 0.38	$ 0.30
	December	$ 0.38	$ 0.20
Calendar Year 2012 by Month	January	$ 0.44	$ 0.19

Notes

(1) Our stock commenced trading on the OTBCC on October 22, 2009.

(2) The closing price on the OTCBB for our common stock on January 31, 2012 was $0.27.

There is currently only a limited public market for the common stock in the United States. There can be no assurance that a more active market will develop in the future.

B. PLAN OF DISTRIBUTION

Not Applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

C. MARKETS

See Item 9.A.

D. SELLING SHAREHOLDERS

Not Applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

E. DILUTION

Not Applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

F. EXPENSES OF THE ISSUE

Not Applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

ITEM 10 ADDITIONAL INFORMATION

A. SHARE CAPITAL

Not Applicable. This Form 20-F is being filed as an Annual Report under the Exchange Act.

B. MEMORANDUM AND ARTICLES OF ASSOCIATION

Certificate of Incorporation

We were incorporated under the Business Corporations Act (Ontario) on September 22, 1978 under the name Bonanza Red Lake Explorations Inc. The corporation number as assigned by Ontario is 396323.

Articles of Amendment dated January 14, 1985

By Articles of Amendment dated January 14, 1985, our Articles were amended as follows:

1. The minimum number of directors of the Company shall be 3 and the maximum number of directors of the Company shall be 10.

2. (a) Delete the existing objects clauses and provide that there are no restrictions on the business we may carry on or on the powers that we may exercise;

(b) Delete the term "head office" where it appears in the articles and substitute therefor the term "registered office";

(c) Delete the existing special provisions contained in the articles and substitute therefor the following:

The following special provisions shall be applicable to the Company:

Subject to the provisions of the Business Corporations Act, as amended or re-enacted from time to time, the directors may, without authorization of the shareholders:

(i) borrow money on the credit of the Company;

(ii) issue, re-issue, sell or pledge debt obligations of the Company;

(iii) give a guarantee on behalf of the Company to secure performance of an obligation of any person;

(iv) mortgage, hypothecate, pledge or otherwise create a security interest in all or any property of the Corporation owned or subsequently acquired, to secure any obligation of the Company; and

(v) by resolution, delegate any or all such powers to a director, a committee of directors or an officer of the Company.

3. (a) Provide that the Company is authorized to issue an unlimited number of shares;

(b) Provide that the Company is authorized to issue an unlimited number of preference shares.

Articles of Amendment dated August 16, 2000

By Articles of Amendment dated August 16, 2000 our articles were amended to consolidate our issued and outstanding common shares on the basis on one common share for every three issued and outstanding common shares in our capital, and change our name from Bonanza Red Lake Explorations Inc. to Eugenic Corp.

Our Articles of Amendment state that there are no restrictions on the business that may carry on, but do not contain a stated purpose or objective.

Articles of Amalgamation dated November 30, 2009

By Articles of Amalgamation dated November 30, 2009 we amalgamated with our wholly owned subsidiary Eagleford Energy Inc. (formerly: 1406768 Ontario Inc.) and changed the entity’s name to Eagleford Energy Inc.

Bylaws

No director of ours is permitted to vote on any resolution to approve a material contract or transaction in which such director has a material interest. (Bylaws, Article 43).

Neither our Articles nor our Bylaws limit the directors’ power, in the absence of an independent quorum, to vote compensation to themselves or any members of their body. The Bylaws provide that directors shall receive remuneration as the board of directors shall determine from time to time. (Bylaws, Article 44).

Under our Articles and Bylaws, our board of directors may, without the authorization of our shareholders, (i) borrow money upon our credit; (ii) issue, reissue, sell or pledge debt obligations of ours; whether secured or unsecured (iii) give a guarantee on behalf of us to secure performance of obligations; and (iv) charge, mortgage, hypothecate, pledge or otherwise create a security interest in all currently owned or subsequently acquired real or personal, movable or immovable, tangible or intangible, property of ours to secure obligations.

Annual general meetings of our shareholders are held on such day as is determined by resolution of the directors. (Bylaws, Article 6). Special meetings of our shareholders may be convened by order of our Chairman of the Board, our President if he/she is a director, a Vice-President who is a director, or the board of directors. (Bylaws, Article 6). Shareholders of record must be given notice of such special meeting not less than 10 days or more than 50 days before the date of the meeting. Notices of special meetings of shareholders must state the nature of the business to be transacted in detail and must include the text of any special resolution or bylaw to be submitted to the meeting. (Bylaws, Article 8). Our board of directors is permitted to fix a record date for any meeting of the shareholders that is between 21 and 50 days prior to such meeting. (Bylaws, Article 9). The only persons entitled to admission at a meeting of the shareholders are shareholders entitled to vote, our directors, our auditors, and others entitled by law, by invitation of the chairman of the meeting, or by consent of the meeting. (Bylaws, Article 13).

Neither our Articles nor our Bylaws discuss limitations on the rights to own securities or exercise voting rights thereon, and there is no provision of our Articles or Bylaws that would delay, defer or prevent a change in control of us, or that would operate only with respect to a merger, acquisition, or corporate restructuring involving us or any of its subsidiaries. Our Bylaws do not contain a provision indicating an ownership threshold above which shareholder ownership must be disclosed.

At the Annual and Special Meeting of Shareholders to be held on February 24, 2012, shareholders will be asked to consider, and if deemed advisable, to repeal and replace the Corporation's current By-Law No. 1 and Special By-Law No. 1 (the " **Old By-Laws** ") with a new By-Law No. 1 (the " **New By-Laws** ") in order to reflect the current circumstances and practices of the Company and certain amendments to the *Business Corporations Act* (Ontario) (the " **OBCA** "), which came into force on August 1, 2007.

The material changes may be summarized as follows:

(a) The quorum necessary for board meetings has changed from requiring two of five directors to a majority of the number of directors or minimum number of directors required by the articles, and if the Corporation has fewer than three directors, all of the directors must be present at any meeting of directors to constitute a quorum for the transaction of business;

(b) Conflict of interest provisions have been added to reflect amendments to the OBCA prohibiting conflicted directors from attending any part of a meeting during which the contract or transaction creating the conflict is discussed;

(c) Indemnity provisions have been added to reflect OBCA amendments which have broadened the language of indemnity coverage to include "investigative or other proceedings in which the indemnitee is involved because of association with the corporation" and which also now permit the Company to advance monies to an indemnified individual for costs, charges and expenses associated with such proceedings;

(d) The record date for notice of meetings of shareholders has been added to reflect OBCA amendments (as a result of this amendment, the record date shall not precede by more than sixty days nor by less than thirty days the date on which the meeting is to be held); and

(e) The notice and waiver provisions have been amended to reflect OBCA amendments that allow for persons to send notices and consents to waive by electronic means in accordance with the *Electronic Commerce Act, 2000* .

Other Provisions

Neither our Articles nor our Bylaws discuss the retirement or non-retirement of directors under an age limit requirement or the number of shares required for director qualification.

Neither our Articles nor our Bylaws require that a director hold a share in the capital of the Company as qualification for his/her office.

Neither our Articles nor our Bylaws contain sinking fund provisions, provisions allowing us to make further capital calls with respect to any shareholder of ours, or provisions which discriminate against any holders of securities as a result of such shareholder owning a substantial number of shares.

C. MATERIAL CONTRACTS

During the two year period preceding the filing date of this Annual Report, we entered into no material contracts other than contracts entered into in the ordinary course except for the following:

Effective June 10, 2010, we retained Gar Wood Securities, LLC (“Gar Wood”) to act as Investment Banker/Financial Advisor to the Company for a period of two years. Under the terms of the Gar Wood engagement, we agreed to pay a fee of 6% of the gross proceeds raised and issue 1,500,000 common share purchase warrants (the “Warrants”) as follows:

1,000,000 Warrants exercisable at US$1.00 to purchase 1,000,000 common shares expiring on December 10, 2011 and issuable in three equal tranches on June 10, 2010, December 10, 2010 and June 10, 2011; and

500,000 Warrants exercisable at US$1.50 to purchase 500,000 common shares expiring on June 10, 2012 and issuable in three equal tranches on June 10, 2010, December 10, 2010 and June 10, 2011. The fair value of the warrants was recorded as compensation expense and contributed surplus

On November 5, 2010 we terminated the agreement with Garwood dated June 10, 2010 and as a result 36,430 warrants were cancelled out of the 333,333 warrants issued exercisable at $1.00 expiring December 10, 2011 and 18,215 warrants were cancelled out of the 166,667 warrants issued exercisable at $1.50 expiring June 10, 2012 and on December 10, 2011, 296,903 common share purchase warrants expired. On December 11, 2011, 296,903 warrants exercisable at $1.00 expired.

On August 31, 2010 we acquired a 10% working interest before payout and a 7.5% working interest after payout of production revenue of $15 million in a mineral lease comprising approximately 2,629 gross acres of land in Zavala County, Texas (the “Lease Interest”). As consideration for the Lease Interest we paid on closing $212,780 (US$200,000), satisfied by US$25,000 paid in cash on closing and $186,183 (US$175,000), 5% secured promissory note.US$100,000 of principal together with accrued interest was due and payable on February 28, 2011 and US$75,000 of principal together with accrued interest was due and payable on August 31, 2011. On March 18, 2011 we paid to Source US$100,000 of the promissory note and on September 1, 2011 we paid the balance of the secured promissory note in full in the amount of US$75,000 together with accrued interest of US$6,250.

On August 31, 2010, we acquired 100% the issued and outstanding membership interests of Dyami Energy LLC, a Texas limited liability corporation for consideration of $4,218,812. (US$3,965,422) satisfied by (i) the issuance of 3,418,467 units of the Company. Each unit is comprised of one common share and one-half a purchase warrant. Each full warrant is exercisable into one additional common share at US$1.00 per share on or before August 31, 2014 (the “Units’) and (ii) the assumption of $1,021,344 (US$960,000) of Dyami Energy debt by way of a secured promissory note. The note bears interest at 6% per annum, is secured by the Leases and was payable on December 31, 2011 or upon the Company closing a financing or series of financings in excess of US$4,500,000. The due date of the note has been extended until June 30, 2012 with an interest rate of 10% per annum.

Dyami Energy holds a 75% working interest before payout and a 61.50% working interest after payout of production revenue of $12.5 million in the Matthews Lease comprising approximately 2,629 gross acres of land in Zavala County, Texas and a 100% working interest in a mineral lease comprising approximately 2,637 acres of land in Zavala County, Texas (the “Murphy Lease”) subject to a 10% carried interest on the drilling costs from surface to base of the Austin Chalk formation, and a 3% carried interest on the drilling costs from the top of the Eagle Ford shale formation to basement on the first well drilled into a serpentine plug and for the first well drilled into a second serpentine plug, if discovered .

D. EXCHANGE CONTROLS

There are no governmental laws, decrees or regulations in Canada that restrict the export or import of capital, or affect the remittance of dividends, interest or other payments to a non-resident holder of our common stock, other than withholding tax requirements (See "Taxation" below).

Except as provided in the Investment Canada Act, there are no limitations imposed under the laws of Canada, the Province of Ontario, or by our constituent documents on the right of a non-resident to hold or vote our common stock.

The Investment Canada Act (the "ICA"), which became effective on June 30, 1985, regulates the acquisition by non-Canadians of control of a Canadian business enterprise. In effect, the ICA requires review by Investment Canada, the agency which administers the ICA, and approval by the Canadian government, in the case of an acquisition of control of a Canadian business by a non-Canadian where: (i) in the case of a direct acquisition (for example, through a share purchase or asset purchase), the assets of the business are CDN $5 million or more in value; or (ii) in the case of an indirect acquisition (for example, the acquisition of the foreign parent of the Canadian business) where the Canadian business has assets of CDN $5 million or more in value or if the Canadian business represents more than 50% of the assets of the original group and the Canadian business has assets of CDN $5 million or more in value. Review and approval are also required for the acquisition or establishment of a new business in areas concerning "Canada's cultural heritage or national identity" such as book publishing, film production and distribution, television and radio production and distribution of music, and the oil and natural gas industry, regardless of the size of the investment.

As applied to an investment in us, three methods of acquiring control of a Canadian business would be regulated by the ICA: (i) the acquisition of all or substantially all of the assets used in carrying on the Canadian business; (ii) the acquisition, directly or indirectly, of voting shares of a Canadian corporation carrying on the Canadian business; or (iii) the acquisition of voting shares of an entity which controls, directly or indirectly, another entity carrying on a Canadian business. An acquisition of a majority of the voting interests of an entity, including a corporation, is deemed to be an acquisition of control under the ICA. An acquisition of less than one-third of the voting shares of a corporation is deemed not to be an acquisition of control. An acquisition of less than a majority, but one-third or more, of the voting shares of a corporation is presumed to be an acquisition of control unless it can be established that on the acquisition the corporation is not, in fact, controlled by the acquirer through the ownership of voting shares. For partnerships, trusts, joint ventures or other unincorporated entities, an acquisition of less than a majority of the voting interests is deemed not to be an acquisition of control.

In 1988, the ICA was amended, pursuant to the Free Trade Agreement dated January 2, 1988 between Canada and the United States, to relax the restrictions of the ICA. As a result of these amendments, except where the Canadian business is in the cultural, oil and gas, uranium, financial services or transportation sectors, the threshold for direct acquisition of control by US investors and other foreign investors acquiring control of a Canadian business from US investors has been raised from CDN $5 million to CDN $150 million of gross assets, and indirect acquisitions are not reviewable.

In addition to the foregoing, the ICA requires that all other acquisitions of control of Canadian businesses by non-Canadians are subject to formal notification to the Canadian government. These provisions require a foreign investor to give notice in the required form, which notices are for information, as opposed to review, purposes.

E. TAXATION

Certain Canadian Federal Income Tax Consequences

The following discussion describes the principal Canadian federal income tax consequences applicable to a holder of our common shares which are traded on the OTCBB, who, at all material times, is a resident of the United States for purposes of the Canada-United States Income Tax Convention (the "Treaty") entitled to the full benefit of the Treaty and is not a resident, or deemed to be a resident, of Canada, deals at arm's length and is not affiliated with the Company, did not acquire our common shares by virtue of employment, is not a financial institution, specified financial institution, registered non-resident insurer, authorized foreign bank, partnership or a trust as defined in the Income Tax Act (Canada) (the "ITA"), holds our common shares as capital property and as beneficial owner, and does not use or hold, is not deemed to use or hold, his or her common shares in connection with carrying on a business in Canada and, did not, does not and will not have a fixed base or permanent establishment in Canada within the meaning of the Treaty (a "non-resident holder").

This description is based upon the current provisions of the ITA, the regulations thereunder (the "Regulations"), management's understanding of the current publicly announced administration and assessing policies of Canada Revenue Agency, and all specific proposals (the "Tax Proposals") to amend the ITA and Regulations announced by the Minister of Finance (Canada) prior to the date hereof. This description is not exhaustive of all possible Canadian federal income tax consequences and, except for the Tax Proposals, does not take into account or anticipate any changes in law, whether by legislative, governmental or judicial action, nor does it take into account any income tax laws or considerations of any province or territory of Canada or foreign tax considerations which may differ significantly from those discussed below.

The following discussion is for general information only and is not intended to be, nor should it be construed to be, legal or tax advice to any holder of common shares of the Company, and no opinion or representation with respect to the Canadian Federal Income Tax consequences to any such holder or prospective holder is made. Accordingly, holders and prospective holders of common shares are urged to consult with their own tax advisors about the federal, provincial and foreign tax consequences of purchasing, owning and disposing of common shares.

Dividends

Dividends paid on our common shares to a non-resident holder will be subject to a 25% withholding tax pursuant to the provision of the ITA. The Treaty provides that the normal 25% withholding tax rate is generally reduced to 15% on dividends paid on shares of a corporation resident in Canada (such as the Company) to beneficial owners who are residents of the United States. However, if the beneficial owner is a resident of the United States and is a corporation which owns at least 10% of the voting stock of the Company, the withholding tax rate on dividends is reduced to 5%.

Capital Gains

A non-resident of Canada is subject to tax under the ITA in respect of a capital gain realized upon the disposition of a share of a corporation if the shares are considered to be "taxable Canadian property" of the holder within the meaning of the ITA and no relief is afforded under an applicable tax treaty. For purposes of the ITA, a common share of the Company will be taxable Canadian property to a non-resident holder if more than 50% of the fair market value of the common share during the 60 month period immediately preceding the disposition of the common share, was derived directly or indirectly from real or immovable property situated in Canada, Canadian resource properties or any options or interests in such properties.

In the case of a non-resident holder to whom shares of our common stock represent taxable Canadian property and who is a resident in the United States and not a former resident of Canada, no Canadian taxes will be payable on a capital gain realized on such shares by reason of the Treaty unless the value of such shares is derived principally from real property situated in Canada within the meaning of the Treaty at the time of the disposition.

Certain United States Federal Income Tax Consequences

The following is a general discussion of certain possible United States Federal income tax consequences, under current law, generally applicable to a US Holder (as defined below) of our common shares. This discussion does not address all potentially relevant Federal income tax matters and does not address consequences peculiar to persons subject to special provisions of Federal income tax law, such as those described below as excluded from the definition of a US Holder. In addition, this discussion does not cover any state, local or foreign tax consequences (See “Certain Canadian Federal Income Tax Consequences” above).

The following discussion is based upon the sections of the Internal Revenue Code of 1986, as amended (the “Code”), Treasury Regulations, published Internal Revenue Service (“IRS”) rulings, published administrative positions of the IRS and court decisions that are currently applicable, any or all of which could be materially and adversely changed, possibly on a retroactive basis, at any time. In addition, this discussion does not consider the potential effects, both adverse and beneficial, of recently proposed legislation which, if enacted, could be applied, possibly on a retroactive basis, at any time. The following discussion is for general information only and it is not intended to be, nor should it be construed to be, legal or tax advice to any holder or prospective holder of common shares, and no opinion or representation with respect to the United States Federal income tax consequences to any such holder or prospective holder is made. Accordingly, holders and prospective holders of common shares are urged to consult their own tax advisors about the Federal, state, local, and foreign tax consequences of purchasing, owning and disposing of common shares.

U.S. Holders

As used herein, a “U.S. Holder” means a holder of common shares who is a citizen or individual resident (as defined under United States tax laws) of the United States; a corporation created or organized in or under the laws of the United States or of any political subdivision thereof; an estate the income of which is taxable in the United States irrespective of source; or a trust if (a) a court within the United States is able to exercise primary supervision over the trust’s administration and one or more United States persons have the authority to control all of its substantial decisions or (b) the trust was in existence on August 20, 1996 and has properly elected to continue to be treated as a United States person. This summary does not address the United States tax consequences to, and U.S. Holder does not include, persons subject to specific provisions of federal income tax law, including but not limited to tax-exempt organizations, qualified retirement plans, individual retirement accounts and other tax-deferred accounts, financial institutions, insurance companies, real estate investment trusts, regulated investment companies, broker-dealers, non-resident alien individuals, persons or entities that have a “functional currency” other than the U.S. dollar, persons who hold common shares as part of a straddle, hedging or a conversion transaction, and persons who acquire their common shares as compensation for services. This discussion is limited to U.S. Holders who own common shares as capital assets and who hold the common shares directly (e.g., not through an intermediary entity such as a corporation, partnership, limited liability company, or trust). This discussion does not address the consequences to a person or entity of the ownership, exercise or disposition of any options, warrants or other rights to acquire common shares.

Distributions on Our Common Shares

Subject to the discussion below regarding passive foreign investment companies ("PFICs"), the gross amount of any distribution (including non-cash property) by us (including any Canadian taxes withheld therefrom) with respect to common shares generally should be included in the gross income of a U.S. Holder as foreign source dividend income to the extent such distribution is paid out of current or accumulated earnings and profits of ours, as determined under United States Federal income tax principles. Distributions received by non-corporate U.S. Holders may be subject to United States Federal income tax at lower rates than other types of ordinary income (generally 15%) in taxable years beginning on or before December 31, 2010 if certain conditions are met. These conditions include the Company not being classified as a PFIC, it being a "qualified foreign corporation," the U.S. Holder's satisfaction of a holding period requirement, and the U.S. Holder not treating the distribution as "investment income" for purposes of the investment interest deduction rules. To the extent that the amount of any distribution exceeds our current and accumulated earnings and profits for a taxable year, the distribution first will be treated as a tax-free return of capital to the extent of the U.S. Holder's adjusted tax basis in our common shares and to the extent that such distribution exceeds the Holder's adjusted tax basis in our common shares, will be taxed as capital gain. In the case of U.S. Holders that are corporations, such dividends generally will not be eligible for the dividends received deduction.

If a U.S. Holder receives a dividend in Canadian dollars, the amount of the dividend for United States federal income tax purposes will be the U.S. dollar value of the dividend (determined at the spot rate on the date of such payment) regardless of whether the payment is later converted into U.S. dollars. In such case, the U.S. Holder may recognize additional ordinary income or loss as a result of currency fluctuations between the date on which the dividend is paid and the date the dividend amount is converted into U.S. dollars.

Disposition of Common Shares

Subject to the discussion below regarding PFIC's, gain or loss, if any, realized by a U.S. Holder on the sale or other disposition of our common shares (including, without limitation, a complete redemption of our common shares) generally will be subject to United States Federal income taxation as capital gain or loss in an amount equal to the difference between the U.S. Holder's adjusted tax basis in our common shares and the amount realized on the disposition. Net capital gain (i.e., capital gain in excess of capital loss) recognized by a non-corporate U.S. Holder (including an individual) upon a sale or other disposition of our common shares that have been held for more than one year will generally be subject to a maximum United States federal income tax rate of 15% subject to the PFIC rules below. Deductions for capital losses are subject to certain limitations. If the U.S. Holder receives Canadian dollars on the sale or disposition, it will have a tax basis in such dollars equal to the U.S. dollar value. Generally, any gain or loss realized on a subsequent disposition of the Canadian dollars will be U.S. source ordinary income or loss.

U.S. "Anti-Deferral" Rules

Passive Foreign Investment Company ("PFIC") Regime . If we, or a non-U.S. entity directly or indirectly owned by us ("Related Entity"), has 75% or more of its gross income as "passive" income, or if the average value during a taxable year of ours or the Related Entity's "passive assets" (generally, assets that generate passive income) is 50% or more of the average value of all assets held by us or the Related Entity, then the United States PFIC rules may apply to U.S. Holders. If we or a Related Entity is classified as a PFIC, a U.S. Holder will be subject to increased tax liability in respect of gain recognized on the sale of his, her or its common shares or upon the receipt of certain distributions, unless such person makes a "qualified electing fund" election to be taxed currently on its *pro rata* portion of our income and gain, whether or not such income or gain is distributed in the form of dividends or otherwise, and we provide certain annual statements which include the information necessary to determine inclusions and assure compliance with the PFIC rules. As another alternative to the foregoing rules, a U.S. Holder may make a mark-to-market election to include in income each year as ordinary income an amount equal to the increase in value of its common shares for that year or to claim a deduction for any decrease in value (but only to the extent of previous mark-to-market gains). We or a related entity can give no assurance as to its status as a PFIC for the current or any future year. U.S. Holders should consult their own tax advisors with respect to the PFIC issue and its applicability to their particular tax situation.

Controlled Foreign Corporation Regime ("CFC") . If a U.S. Holder (or person defined as a U.S. persons under Section 7701(aX301 of the Code) owns 10% or more of the total combined voting power of all classes of our stock (, a "U. S. Shareholder") and U.S. Shareholders own more than 50% of the vote or value of our Company, we would be a "controlled foreign corporation".. This classification would result in many complex consequences, including the required inclusion into income by such U. S. Shareholders of their pro rata shares of "Subpart F income" of our Company (as defined by the Code) and our earnings invested in "US property" (as defined by the Code). In addition, under Section 1248 of the Code, gain from the sale or exchange of our common shares by a US person who is or was a U. S. Shareholder at any time during the five year period before the sale or exchange may be treated as ordinary income to the extent of earnings and profits of ours attributable to the stock sold or exchanged. It is not clear the CFC regime would apply to the U.S. Holders of our common shares, and is outside the scope of this discussion.

Foreign Tax Credit

A U.S. Holder who pays (or has withheld from distributions) Canadian income tax with respect to us may be entitled to either a deduction or a tax credit for such foreign tax paid or withheld, at the option of the U.S. Holder. Generally, it will be more advantageous to claim a credit because a credit reduces United States federal income tax on a dollar-for-dollar basis, while a deduction merely reduces the taxpayer's income subject to tax. This election is made on a year-by-year basis and generally applies to all foreign taxes paid by (or withheld from) the U.S. Holder during that year.

There are significant and complex limitations which apply to the credit, among which is the general limitation that the credit cannot exceed the proportionate share of the U.S. Holder's United States income tax liability that the U.S. Holder's foreign source income bears to its worldwide taxable income. This limitation is designed to prevent foreign tax credits from offsetting United States source income. In determining this limitation, the various items of income and deduction must be classified into foreign and domestic sources. Complex rules govern this classification process.

In addition, this limitation is calculated separately with respect to specific "baskets" of income such as passive income, high withholding tax interest, financial services income, shipping income, and certain other classifications of income. Foreign taxes assigned to a particular class of income generally cannot offset United States tax on income assigned to another class. Under the American Jobs Creation Act of 2004 (the "Act"), this basket limitation will be modified significantly after 2006.

Unused foreign tax credits can generally be carried back one year and carried forward ten years. U.S. Holders should consult their own tax advisors concerning the ability to utilize foreign tax credits, especially in light of the changes made by the Act.

Backup Withholding

Payment of dividends and sales proceeds that are made within the United States or through certain U.S.-related financial intermediaries generally are subject to information reporting requirement and to backup withholding unless the US Holder (i) is a corporation or other exempt recipient or (ii) in the case of backup withholding, provides a correct taxpayer identification number and certifies that no loss of exemption from backup withholding has occurred

The amount of any backup withholding from a payment to a US Holder will be allowed as a credit against the US Federal income tax liability of the US Holder and may entitle the US Holder to a refund, provided that the required information is furnished to the IRS.

F. DIVIDENDS AND PAYING AGENTS

Not Applicable. This Form 20-F is being filed as an Annual Report filed under the Exchange Act.

G. STATEMENT BY EXPERTS

Not Applicable. This Form 20-F is being filed as an Annual Report filed under the Exchange Act.

H. DOCUMENTS ON DISPLAY

The documents and exhibits referred to in this Annual Report are available for inspection at the registered and management office at 1 King Street West, Suite 1505, Toronto, Ontario M5H 1A1 during normal business hours.

I. SUBSIDIARY INFORMATION

Not Applicable. This Form 20-F is being filed as an Annual Report filed under the Exchange Act.

ITEM 11 QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

The Company is exposed in varying degrees of risks arising from financial its instruments. The Company does not participate in the use of derivative financial instruments to mitigate these risks and has no designated hedging transactions. The Board approves and monitors the risk management processes. The Board's main objectives for managing risks are to ensure liquidity, the fulfillment of obligations and limited exposure to credit and market risks while ensuring greater returns on any surplus funds. There were no changes to the objectives or the process from the prior year. Cash and cash equivalents and marketable securities are the only financial instruments and are classified as level 1 financial instruments in the fair value hierarchy.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective April 1, 2009, the Company adopted the recommendations of the Emerging Issues Committee Abstract EIC -173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities" which states that an entity's own credit and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities. These recommendations were particularly applied in evaluating the fair values of the Company's marketable securities.

The types of risk exposure and the ways in which such exposures are managed are as follows:

Credit Risk

Concentration risks exist in cash and cash equivalents because significant balances are maintained with one financial institution and a brokerage firm. The risk is mitigated because the financial institution is an international bank and the brokerage firm is a reputable Canadian brokerage firm.

Liquidity Risk

The Company monitors its liquidity position regularly to assess whether it has the funds necessary to fulfill planned exploration commitments on its oil and gas properties or that viable options are available to fund such commitments from new equity issuances or alternative sources such as farm-out agreements. However, as an exploration company at an early stage of development and without significant internally generated cash flow, there are inherent liquidity risks, including the possibility that additional financing may not be available to the Company, or that actual exploration expenditures may exceed those planned. The current uncertainty in global markets and ongoing litigations could have an impact on the Company's future ability to access capital on terms that are acceptable to the Company. The Company has so far been able to raise the required financing to meet its obligation on time.

Market Risk

Market risk represents the risk of loss that may impact our financial position, results of operations, or cash flows due to adverse changes in financial market prices, including interest rate risk, foreign currency exchange rate risk, commodity price risk, and other relevant market or price risks. The Company does not use derivative financial instruments or derivative commodity instruments to mitigate this risk.

The oil and gas industry is exposed to a variety of risks including the uncertainty of finding and recovering new economic reserves, the performance of hydrocarbon reservoirs, securing markets for production, commodity prices, interest rate fluctuations, potential damage to or malfunction of equipment and changes to income tax, royalty, environmental or other governmental regulations.

Market events and conditions in recent years including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions have caused significant volatility to commodity prices. These conditions caused a loss of confidence in the broader U.S. and global credit and financial markets. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and may impact the performance of the global economy going forward. Although economic conditions improved towards the latter portion of 2009, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

The Company mitigates these risks by:

- utilizing competent, professional consultants as support teams to company staff.
- performing geophysical, geological or engineering analyses of prospects.
- focusing on a limited number of core properties.

(i) Commodity Price Risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand.

The Company believes that movement in commodity prices that are reasonably possible over the next twelve month period will not have a significant impact on the Company.

Commodity Price Sensitivity

The following table summarizes the sensitivity of the fair value of the Company's risk management position for the year ended August 31, 2011 and 2010 to fluctuations in natural gas prices, with all other variables held constant. When assessing the potential impact of these price changes, the Company believes that 10 percent volatility is a reasonable measure. Fluctuations in natural gas prices potentially could have resulted in unrealized gains (losses) impacting net income as follows:

	2011		2010	
	Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
Revenue	$ 78,965	$ 64,607	$ 115,911	$ 94,837
Net loss	$ (745,378)	$ (759,736)	$ (678,172)	$ (699,246)

(ii) Currency Risk

The Company is exposed to the fluctuations in foreign exchange rates. The prices received by the Company for the production of natural gas and natural gas liquids are primarily determined in reference to United States dollars but are settled with the Company in Canadian dollars. The Company's cash flow for commodity sales will therefore be impacted by fluctuations in foreign exchange rates.

The Company operates in Canada and a portion of its expenses are incurred in U.S. dollars. A significant change in the currency exchange rates between the CDN dollar relative to US dollar could have an effect on the Company's results of operations, financial position or cash flows.

The Company is exposed to currency risk through the following assets and liabilities denominated in US dollars at August 31, 2011 and 2010:

Financial Instruments	2011	2010
Cash and cash equivalents	$ 117,383	$ 5,046
Accounts receivable	72,487	21,926
Due from related party	-	1,245
Accounts payable	656,401	198,015
Shareholder loans	2,790,000	-
Secured notes payable	1,035,000	1,135,000
Total US$	$ 4,671,271	$ 1,361,232
CDN dollar equivalent at year end (1)	$ 4,570,372	$ 1,448,215

(1) Translated at the exchange rate in effect at August 31, 2011 $0.9784 (August 31, 2010 - $1.0639)

For the year ended August 31, 2011 the Company had a foreign exchange gain of $164,800 due to the fluctuations in the CDN dollar compared to the US dollar. For the year ended August 31, 2011 a 1% increase/decrease in the exchange rate is estimated to give rise to a change in net loss and comprehensive loss of approximately $1,904. The Company does not use derivative financial instruments to reduce its foreign exchange exposure.

(iii) Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. The majority of the Company's debt is short-term in nature with fixed rates.

Based on management's knowledge and experience of the financial markets, the Company believes that the movements in interest rates that are reasonably possible over the next twelve month period will not have a significant impact on the Company.

ITEM 12 DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

A. DEBT SECURITIES

Not applicable.

B. WARRANTS AND RIGHTS

Not applicable.

C. OTHER SECURITIES

Not Applicable.

D. AMERICAN DEPOSITORY SHARES

Not Applicable.

PART II

ITEM 13 DEFAULTS, DIVIDENDS ARREARAGES AND DELINQUENCIES

Not applicable.

ITEM 14 MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

Not applicable.

ITEM 15 CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Under the supervision and with the participation of our senior management, including our chief executive officer and chief financial officer, James Cassina, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as of the end of the period covered by this annual report (the "Evaluation Date"). Based on this evaluation, our chief executive officer and chief financial officer concluded as of the Evaluation Date that our disclosure controls and procedures were effective such that the information relating to us, required to be disclosed in our Securities and Exchange Commission ("SEC") reports (i) is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and (ii) is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with generally accepted accounting principles.

Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; (ii) provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on our financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Management assessed the effectiveness of our internal control over financial reporting as of August 31, 2011 based on the framework established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that assessment, management concluded that, as of August 31, 2011, our internal control over financial reporting was effective based on the criteria established in Internal Control—Integrated Framework.

Limitations on Effectiveness of Controls and Procedures

Our management, including our Chief Executive Officer (Principal Executive Officer) and Chief Financial Officer (Principal Financial Officer), does not expect that our disclosure controls and procedures or our internal controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our control systems are designed to provide such reasonable assurance of achieving their objectives. Further, the design of a control system must reflect the fact that there are resource constraints and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our Company have been detected. These inherent limitations include, but are not limited to, the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarter ended August 31, 2011 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 16 [RESERVED]

A. AUDIT COMMITTEE FINANCIAL EXPERT

Our Board of Directors has determined that Mr. Milton Klyman is an "audit committee financial expert", as defined in Item 16A of Form 20-F and is independent. Milton Klyman is the Chairman of the Audit Committee. He is a self-employed financial consultant and has been a Chartered Accountant since 1952. Milton Klyman is a Life Member of the Institute of Chartered Accountants of Ontario, a Life member of the Canadian Institute of Mining Metallurgy and Petroleum and a Fellow of the Institute of Chartered Secretaries and Administrators.

B. CODE OF ETHICS

We have adopted a written code of business conduct and ethics (the "Code") for our directors, officers and employees. The board encourages following the Code by making it widely available. It is distributed to directors in the Director's Manual and to officers, employees and consultants at the commencement of their employment or consultancy. The Code reminds those engaged in service to us that they are required to report perceived or actual violations of the law, violations of our policies, dangers to health, safety and the environment, risks to our property, and accounting or auditing irregularities to the chair of the Audit Committee who is an independent director of ours. In addition, to requiring directors, officers and employees to abide by the Code, we encourage consultants, service providers and all parties who engage in business with us to contact the chair of the Audit Committee regarding any perceived and all actual breaches by our directors, officers and employees of the Code. The chair of our Audit Committee is responsible for investigating complaints, presenting complaints to the applicable board committee or the board as a whole, and developing a plan for promptly and fairly resolving complaints. Upon conclusion of the investigation and resolution of a complaint, the chair of our Audit Committee will advise the complainant of the corrective action measures that have been taken or advise the complainant that the complaint has not been substantiated. The Code prohibits retaliation by us, our directors and management, against complainants who raise concerns in good faith and requires us to maintain the confidentiality of complainants to the greatest extent practical. Complainants may also submit their concerns anonymously in writing. In addition to the Code, we have an Audit Committee Charter and a Policy of Procedures for Disclosure Concerning Financial/Accounting Irregularities.

Since the beginning of our most recently completed financial year, no material change reports have been filed that pertain to any conduct of a director or executive officer that constitutes a departure from the Code. The board encourages and promotes a culture of ethical business conduct by appointing directors who demonstrate integrity and high ethical standards in their business dealings and personal affairs. Directors are required to abide by the Code and expected to make responsible and ethical decisions in discharging their duties, thereby setting an example of the standard to which management and employees should adhere. The board is required by the Board Mandate to satisfy our CEO and other executive officers are acting with integrity and fostering a culture of integrity throughout the Company. The board is responsible for reviewing departures from the Code, reviewing and either providing or denying waivers from the Code, and disclosing any waivers that are granted in accordance with applicable law. In addition, the board is responsible for responding to potential conflict of interest situations, particularly with respect to considering existing or proposed transactions and agreements in respect of which directors or executive officers advise they have a material interest. The Board Mandate requires that directors and executive officers disclose any interest and the extent, no matter how small, of their interest in any transaction or agreement with us, and that directors excuse themselves from both board deliberations and voting in respect of transactions in which they have an interest. By taking these steps the board strives to ensure that directors exercise independent judgment, unclouded by the relationships of the directors and executive officers to each other and us, in considering transactions and agreements in respect of which directors and executive officers have an interest. Our Code applies to our directors, officers and employees, including our principal executive officer, principal financial officer, principal accounting officer or persons performing similar functions of the Company. There have been no waivers of our Code granted to our principal executive officer, principal financial officer, principal accounting officer or controller, or similar persons during the period covered by this Annual Report.

Upon written request to us at our registered and management office attention: the President, we will provide by mail, to any person without charge a copy of our Code of Ethics.

C. PRINCIPAL ACCOUNTANT FEES AND SERVICES

It is the policy of the Audit Committee that all audit and non-audit services are pre-approved prior to engagement. Before the initiation of each audit, the principal accountant submits a budget of the expected range of expenditures to complete their audit engagement (including Audit Fees, Audit-Related Fees and Tax Fees) to the Audit Committee for approval. In the event that the principal accountant exceeds these parameters, the individual auditor is expected to communicate to management the reasons for the variances, so that such variances can be ratified by the Audit Committee. As a result, 100% of expenditures within the scope of the noted budget are approved by the Audit Committee.

During fiscal 2011 and 2010 there were no hours performed by any person other than the primary accountant's fulltime permanent employees.

Since the commencement of the Company's most recently completed financial year, no recommendations were made by the Audit Committee to nominate or compensate an external auditor.

External Auditor Service Fees (By Category)

The aggregate fees billed or accrued for professional fees rendered by Schwartz Levitsky Feldman llp, Chartered Accountants for the years ended August 31, 2011 and August 31, 2010 are as follows:

Nature of Services	Fees Paid to Auditor in Year-ended August 31, 2011	Fees Paid to Auditor in Year-ended August 31, 2010
Audit Fees [(1)]	$ 55,000	$ 37,000
Audit-Related Fees [(2)]	Nil	$ 4,900
Tax Fees [(3)]	Nil	7,500
All Other Fees [(4)]	Nil	Nil
TOTALS	**$ 55,000**	**$ 49,400**

Notes:

1. " **Audit Fees** " include fees necessary to perform the annual audit and any quarterly reviews of the Company's financial statements management discussion and analysis. This includes fees for the review of tax provisions and for accounting consultations on matters reflected in the financial statements. This also includes audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

2. " **Audit-Related Fees** " include fees for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and that are not included in "Audit Fees".

3. " **Tax Fees** " include fees for all professional services rendered by the Company's auditors for tax compliance, tax advice and tax planning.

4. " **All Other Fees** " include all fees for products and services provided by the Company's auditors not included in "Audit Fees", "Audit-Related Fees" and "Tax Fees".

D. EXEMPTIONS FROM THE LISTING STANDARDS FOR AUDIT COMMITTEES

Not Applicable.

E. PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASERS

Not applicable.

F. CHANGE IN REGISTRANT'S CERTIFYING ACCOUNTANT

Not Applicable.

G. CORPORATE GOVERNANCE

Not applicable.

PART III

ITEM 17 FINANCIAL STATEMENTS

The following attached Consolidated Financial Statements are included in this Annual Report on Form 20-F beginning on page F-1:

1. Audited Consolidated Financial Statements of Eagleford Energy Inc. for the years ended August 31, 2011, 2010 and 2009, comprised of the following:

   (a) Management Report

   (b) Independent Auditor's Report of Schwartz Levitsky Feldman LLP, Chartered Accountants for the years ended August 31, 2011, 2010 and 2009;

   (c) Consolidated Balance Sheets as at August 31, 2011 and 2010;

(d) Consolidated Statements of Operations and Comprehensive Loss for the years ended August 31, 2011, 2010 and 2009;

(e) Consolidated Statements of Cash Flows for the years ended August 31, 2011, 2010 and 2009;

(f) Consolidated Statements of Shareholders' Equity for the years ended August 31, 2011, 2010 and 2009;

(g) Notes to Consolidated Financial Statements.

ITEM 18 FINANCIAL STATEMENTS

We have elected to provide financial statements pursuant to Item 17.

ITEM 19 EXHIBITS

The following exhibits are included in the Annual Report on Form 20-F:

1.1*	Certificate of Incorporation of Bonanza Red Lake Explorations Inc. (presently known as Eagleford Energy Inc.) dated September 22, 1978
1.2*	Articles of Amendment dated January 14, 1985
1.3*	Articles of Amendment dated August 16, 2000
1.4*	Bylaw No 1 of Bonanza Red Lake Explorations Inc. (presently known as Eagleford Energy Inc.)
1.5*	Special By-Law No 1 – Respecting the borrowing of money and the issue of securities of Bonanza Red Lake Explorations Inc. (presently known as Eagleford Energy Inc.)
1.6***	Articles of Amalgamation dated November 30, 2009
4.1*	2000 Stock Option Plan
4.2*	Code of Business Conduct and Ethics
4.3*	Audit Committee Charter
4.4*	Petroleum and Natural Gas Committee Charter
4.5*	Compensation Committee Charter
4.6*	Purchase and Sale Agreement dated February 5, 2008 among Eugenic Corp., 1354166 Alberta Ltd., and the Vendors of 1354166 Alberta Ltd.
4.7 **	Amended Audit Committee Charter
4.8****	Amended Stock Option Plan
4.9******	Asset Purchase Agreement between Eagleford Energy Inc., and Source Re-Work Program Inc., dated May 12, 2010
4.10******	Addendum dated June 10, 2010 to the Asset Purchase Agreement between Eagleford Energy Inc., and Source Re-Work Program Inc., dated May 12, 2010
4.11******	Addendum 2 dated June 30, 2010 to the Asset Purchase Agreement between Eagleford Energy Inc., and Source Re-Work Program Inc., dated May 12, 2010
4.12*****	Acquisition Agreement among Eagleford Energy Inc., Dyami Energy LLC and the Members of Dyami Energy LLC dated August 10, 2010
4.13******	Financial Advisory Services Agreement between Eagleford Energy Inc. and GarWood Securities, LLC dated June 10, 2010

4.14*******	Amended Stock Option Plan February 24, 2011
4.15********	Amendment dated December 31, 2010 to 6% Secured Promissory Note between Eagleford Energy Inc. and Benchmark Enterprises LLC
4.16********	Consent of Sproule Associates Limited
4.17	Evaluation of the P&NG Reserve of Eagleford Energy Inc.
8.1********	Subsidiaries of Eagleford Energy Inc.
12.1/12.2	Section 302 Certification of Chief Executive and Financial Officer
13.1/13.2	Section 906 Certification of Chief Executive and Financial Officer

*****	Previously filed by Registrant on April 29, 2009 as part of Registration Statement on Form 20 F (SEC File No. 0 53646)
******	Previously Filed by Registrant as part of Amendment #2 to Registration Statement on Form 20F/A on July 14, 2009 (SEC File No. 0-53646)
*******	Previously Filed by Registrant on Form 6-K on December 1, 2009
********	Previously filed by Registrant on Form 20F/A on March 12, 2010
*****	Previously filed by Registrant on Form 6-K on September 16, 2010
******	Previously Filed by Registrant on Form 20F on February 11, 2011
*******	Previously filed by Registrant on Form 6-K on January 27, 2011
********	Previously filed by Registrant on Form 20F on February 16, 2012

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this Annual Report on its behalf.

EAGLEFORD ENERGY INC.

By: /s/ James Cassina
Name: James Cassina
Title: President and Chief Executive Officer

Date: April 23, 2012

INDEX TO FINANCIAL STATEMENTS

1. Audited Consolidated Financial Statements of Eagleford Energy Inc. for the years ended August 31, 2011, 2010 and 2009, comprised of the following:

MANAGEMENT REPORT

To the Shareholders of Eagleford Energy Inc.:

Management is responsible for the preparation and presentation of the accompanying consolidated financial statements, including responsibility for significant accounting judgments and estimates in accordance with Canadian generally accepted accounting principles. This responsibility includes selecting appropriate accounting principles and methods, and making decisions affecting the measurement of transactions in which objective judgment is required.

In discharging its responsibilities for the integrity and fairness of the financial statements, management designs and maintains the necessary accounting systems and related internal controls to provide reasonable assurance that transactions are authorized, assets are safeguarded and financial records are properly maintained to provide reliable information for the preparation of financial statements.

The Board of Directors is responsible for overseeing management in the performance of its financial reporting responsibilities. The Board fulfils these responsibilities by reviewing the financial information prepared by management and discussing relevant matters with management and external auditors. The Board is also responsible for recommending the appointment of the Company's external auditors.

Schwartz Levitsky Feldman llp, an independent firm of Chartered Accountants, is appointed by the shareholders to audit the financial statements and report directly to the shareholders; their report follows. The external auditors have full and free access to, and are available to meet periodically and separately with, the Audit Committee of the Board and management to discuss their audit findings. The Board of Directors approved the consolidated financial statements.

/s/ James Cassina	/s/ Milton Klyman
James Cassina, President	Milton Klyman, Director

December 22, 2011

Schwartz Levitsky Feldman llp
CHARTERED ACCOUNTANTS
LICENSED PUBLIC ACCOUNTANTS
TORONTO • MONTREAL

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Eagleford Energy Inc.
We have audited the accompanying consolidated financial statements of Eagleford Energy Inc., which comprise the consolidated balance sheets as at August 31, 2011 and 2010 and the consolidated statements of operations, comprehensive loss, shareholders' equity and cash flows for each of the three years ended August 31, 2011, 2010 and 2009 and summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Eagleford Energy Inc. as at August 31, 2011 and 2010, and its financial performance and its consolidated cash flows for the years ended August 31, 2011, 2010 and 2009 in accordance with Canadian generally accepted accounting principles.

Emphasis of Matter
Without qualifying our opinion, we draw your attention to Note 1 in the consolidated financial statements which indicates that the Company incurred a net loss of $752,557 during the year ended August 31, 2011 and, as of that date the Company's current liabilities exceeded its current assets by $4,870,621. These conditions, along with other matters as set forth in Note 1 describes matters indicate the existence of a material uncertainty that may cast significant doubt about the Company's ability to continue as going concern.

/s/ SCHWARTZ LEVITSKY FELDMAN LLP

Toronto, Ontario , Canada
December 22, 2011

Chartered Accountants
Licensed Public Accountants

2300 Yonge Street, Suite 1500
Toronto, Ontario M4P 1E4
Tel: 416 785 5353
Fax: 416 785 5663

Consolidated Balance Sheets
(Expressed in Canadian Dollars)

August 31,	**2011**	2010
Assets		
Current		
Cash and cash equivalents	**$ 165,266**	$ 43,776
Marketable securities (Note 6)	**1**	1
Accounts receivable (Note 5)	**127,546**	53,060
Prepaid expenses and deposits (Note 9(i))	**44,285**	-
Due from related party (Note 10)	**-**	1,325
	337,098	98,162
Oil and gas interests (Note 7)		
Developed	**243,000**	314,000
Undeveloped	**8,898,128**	5,695,290
	9,141,128	6,009,290
	$ 9,478,226	$ 6,107,452
Liabilities		
Current		
Accounts payable and accrued liabilities	**$ 1,258,839**	$ 488,741
Secured notes payable (Note 12)	**1,012,644**	186,183
Shareholder loans (Note 10)	**2,936,236**	57,500
Loan payable (Note 11)	**-**	110,000
	5,207,719	842,424
Long term		
Secured notes payable (Note 12)	**-**	1,021,344
Asset retirement obligations (Note 8)	**50,208**	3,907
	50,208	1,025,251
	5,257,927	1,867,675
Shareholders' Equity		
Share capital (Note 9)	**4,635,556**	3,817,184
Warrants (Note 9)	**1,969,516**	2,096,078
Contributed surplus (Note 9)	**85,019**	43,750
Deficit	**(2,469,792)**	(1,717,235)
	4,220,299	4,239,777
	$ 9,478,226	$ 6,107,452

Going Concern (Note 1)
Related Party Transactions and Balances (Note10)
Commitments and Contingencies (Note 18)
Subsequent Events (Note 19)

On behalf of the Board:

/s/ James Cassina Director

/s/ Milton Klyman Director

The accompanying notes are an integral part of these consolidated financial statements

Consolidated Statements of Operations and Comprehensive Loss
(Expressed in Canadian Dollars)

For the years ended August 31	**2011**	2010	2009
Oil and Gas Operations			
Revenue	**$ 71,786**	$ 105,374	$ 56,199
Operating Costs	**67,611**	102,590	83,187
Depletion	**23,136**	38,370	26,638
	90,747	140,960	109,825
Loss from oil and gas operations	**(18,961)**	(35,586)	(53,626)
Expenses			
Management fees (Note10)	**56,250**	24,000	18,000
Office and general	**16,142**	2,474	5,150
Professional fees	**210,633**	152,844	106,770
Transfer and registrar costs	**61,560**	45,206	24,965
Head office services	**113,828**	41,738	16,125
Write down of oil and gas interests	**49,464**	54,630	105,805
Interest	**265,889**	5,750	-
Salaries and wages	**44,061**	-	-
Marketing and public relations	**88,569**	-	-
Gain on foreign exchange	**(164,800)**	-	-
Consulting fees	**-**	326,511	-
	741,596	653,153	276,815
Operating loss for the year before under noted items	**(760,557)**	(688,739)	(330,441)
Gain on disposal of marketable securities	**8,000**	-	-
Interest	**-**	30	1,580
Net loss and comprehensive loss	**$ (752,557)**	$ (688,709)	$ (328,861)
Loss per share, basic and diluted	**$ (0.024)**	$ (0.028)	$ (0.019)
Weighted average shares outstanding (Note 9)	**31,927,228**	24,687,130	17,646,295

The accompanying notes are an integral part of these consolidated financial statements

Consolidated Statements of Cash Flows
(Expressed in Canadian Dollars)

For the years ended August 31,	2011	2010	2009
Cash provided by (used in)			
Operating activities			
Net loss for the year	**$ (752,557)**	$ (688,709)	$ (328,861)
Adjustments for non-cash items:			
Depletion	**23,136**	38,370	26,638
Accretion of asset retirement obligations	**551**	273	130
Write-down of oil and gas interests	**49,464**	54,630	105,805
Imputed interest	**5,750**	5,750	-
Asset retirement obligations	**45,750**	-	-
Shares and warrants issued for services (Note 20)	**88,569**	326,511	-
Gain on disposal of marketable securities	**(8,000)**	-	-
Unrealized foreign exchange gain	**(96,443)**	-	-
Net change in non-cash working capital (Note 20)	**696,937**	43,855	23,955
	53,157	(219,320)	(172,333)
Investing activities			
Oil and gas interests, net	**(3,204,438)**	(26,597)	(10,000)
Proceeds on disposal of marketable securities	**8,000**	-	-
Acquisition of 1354166 Alberta Ltd.	**-**	-	90,499
Acquisition of Dyami Energy LLC	**-**	5,369	-
	(3,196,438)	(21,228)	80,499
Financing activities			
Warrants exercised	**594,475**	147,000	-
Shareholder loans	**2,878,736**	-	-
Secured notes payable, net	**(98,440)**	-	-
Repayment of loan payable	**(110,000)**	-	-
Share issue costs on acquisition of Dyami Energy LLC	**-**	(35,581)	-
Proceeds from private placements, net	**-**	-	180,013
Repayment to note holders pursuant to acquisition of 1354166 Alberta Ltd.	**-**	-	(118,000)
	3,264,771	111,419	62,013
Net increase (decrease) in cash for the year	**121,490**	(129,129)	(29,821)
Cash and cash equivalents, beginning of year	**43,776**	172,905	202,726
Cash and cash equivalents, end of year	**$ 165,266**	$ 43,776	$ 172,905
Cash and cash equivalents consists of:			
Cash	**$ 165,266**	$ 43,776	$ 72,392
Guaranteed investment certificates	**-**	-	100,513
	$ 165,266	$ 43,776	$ 172,905

Supplemental Cash Flow Information and Non-cash Transactions (Note 20)

The accompanying notes are an integral part of these consolidated financial statements

EAGLEFORD ENERGY INC

Consolidated Statements of Shareholders' Equity
(Expressed in Canadian Dollars)
For the years ended August 31, 2011, 2010 and 2009

	(Note 9) SHARE CAPITAL		(Note 9) WARRANTS		(Note 9) CONTRI-BUTED SURPLUS	DEFICIT	TOTAL
	Number	Amount	Number	Amount			
Balance August 31, 2008	10,471,739	$ 467,604	2,575,000	$ 100,875	$ 38,000	$ (699,665)	$ (93,186)
Private placement	2,600,000	67,600	2,600,000	62,400	-	-	130,000
Private placement	1,000,256	26,007	1,000,256	24,006	-	-	50,013
Issuance of units on acquisition of 1354166 Alberta Ltd.	8,910,564	231,675	8,910,564	213,853	-	-	445,528
Debt settlement	1,250,000	32,500	1,250,000	30,000	-	-	62,500
Net loss for the year					-	(328,861)	(328,861)
Balance August 31, 2009	24,232,559	825,386	16,335,820	431,134	38,000	(1,028,526)	265,994
Warrants exercised	2,100,000	197,400	(2,100,000)	(50,400)			147,000
Warrants issued for services			500,000	326,511			326,511
Issuance of units on acquisition of Dyami Energy LLC	3,418,467	2,829,979	1,709,233	1,388,833			4,218,812
Transaction costs		(35,581)					(35,581)
Imputed interest					5,750		5,750
Net loss for the year						(688,709)	(688,709)
Balance August 31, 2010	29,751,026	3,817,184	16,445,053	2,096,078	43,750	(1,717,235)	4,239,777
Warrants exercised	3,710,346	722,572	(3,710,346)	(128,097)			594,475
Units issued as compensation	100,000	95,800	50,000	37,054			132,854
Warrants cancelled			(54,645)	(35,519)	35,519		-
Imputed interest					5,750		5,750
Net loss and comprehensive loss for the year						(752,557)	(752,557)
Balance August 31, 2011	**33,561,372**	**$ 4,635,556**	**12,730,062**	**$ 1,969,516**	**$ 85,019**	**$ (2,469,792)**	**$ 4,220,299**

The accompanying notes are an integral part of these consolidated financial statements

Notes to Consolidated Financial Statements
(Expressed in Canadian Dollars)
For the years ended August 31, 2011, 2010 and 2009

1. Nature of Operations and Going Concern

Eagleford Energy Inc.’s (“Eagleford” or the “Company”) business focus consists of acquiring, exploring and developing oil and gas interests. The recoverability of the amount shown for these properties is dependent upon the existence of economically recoverable reserves, the ability of the Company to obtain the necessary financing to complete exploration and development, and future profitable production or proceeds from disposition of such property. In addition the Company holds a 0.3% net smelter return royalty on 8 mining claim blocks located in Red Lake, Ontario which is carried on the consolidated balance sheets at nil. The Company’s common shares trade on the NASD OTCBB under the symbol EFRDF.

These consolidated financial statements have been prepared on a going concern basis which contemplates the realization of assets and the payment of liabilities in the ordinary course of business.

The Company has accumulated significant losses and negative cash flows from operations in recent years which raises doubt as to the validity of the going concern assumption. As at August 31, 2011, the Company had a working capital deficiency of $4,870,621 and an accumulated deficit of $2,469,792. Management of the Company does not have sufficient funds to meet its liabilities for the ensuing twelve months as they fall due. In assessing whether the going concern assumption is appropriate, management takes into account all available information about the future, which is at least, but not limited to, twelve months from the end of the reporting period. The Company's ability to continue operations and fund its liabilities is dependent on management's ability to secure additional financing and cash flow. Management is pursuing such additional sources of financing and cash flow to fund its operations and obligations and while it has been successful in doing so in the past, there can be no assurance it will be able to do so in the future. Management is aware, in making its assessment, of material uncertainties related to events or conditions that may cast significant doubt upon the Company's ability to continue as a going concern. Accordingly, they do not give effect to adjustments that would be necessary should the Company be unable to continue as a going concern and therefore realize its assets and liquidate its liabilities and commitments in other than the normal course of business and at amounts different from those in the accompanying consolidated financial statements.

The Company plans to obtain additional financing by way of debt or the issuance of common shares or some other means to service its current working capital requirements, any additional or unforeseen obligations or to implement any future opportunities.

2. Significant Accounting Policies

These consolidated financial statements of Eagleford have been prepared in accordance with generally accepted accounting principles in Canada (“Canadian GAAP”). The preparation of these consolidated financial statements in accordance with generally accepted accounting principles in United States (“US GAAP”) have resulted in differences to the consolidated balance sheets and the consolidated statements of operations and comprehensive loss and consolidated statements of shareholders’ equity from the consolidated financial statements prepared using Canadian GAAP (see Note 17).

2. Significant Accounting Policies (cont'd)

Principles of Consolidation

On November 12, 2009, the Company's wholly owned subsidiary, 1406768 Ontario Inc. changed its name to Eagleford Energy Inc. On November 30, 2009 the Company amalgamated with Eagleford Energy Inc. and continued operations as Eagleford Energy Inc. The consolidated financial statements include the accounts of Eagleford, the legal parent, together with its wholly owned subsidiaries, 1354166 Alberta Ltd., an Alberta operating company, and Dyami Energy LLC, a Texas limited liability exploration stage company. All inter-company account transactions have been eliminated on consolidation.

Oil and Gas Interests

The Company follows the successful efforts method of accounting for its oil and gas interests. Under this method, costs related to the acquisition, exploration, and development of oil and gas interests are capitalized. The Company carries as an asset, exploratory well costs if a) the well found has sufficient quantity of reserves to justify its completion as a producing well and b) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. If a property is not productive or commercially viable, its costs are written off to operations. Impairment of non-producing properties is assessed based on management's expectations of the properties.

Developed oil and gas reserves - Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction means is by not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expect to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on any undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at great distances;
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are schedules to be drilled within five years, unless the specific circumstances justify a longer time; and
(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

2. Significant Accounting Policies (cont'd)

Depletion and Depreciation

Depletion of oil and gas properties and depreciation of production equipment are calculated on the unit of production basis based on:

(a) total estimated proved reserves calculated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities;

(b) total capitalized costs, excluding undeveloped lands and unproved costs, plus estimated future development costs of proved undeveloped reserves; and

(c) relative volumes of oil and gas reserves and production, before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Impairment of Long-Lived Assets

The carrying values of property and equipment are reviewed for impairment whenever events or circumstances indicate that the recoverable amount may be less than the carrying value. The determination of when to recognize an impairment loss for a long-lived asset to be held and used is made when its carrying value exceeds the total undiscounted cash flows expected from its use and eventual disposition. When impairment is indicated, the amount of the impairment loss is determined as the excess of the carrying value of the amount over its fair value based on estimated discounted cash flows from use or disposition.

Revenue Recognition

Revenues from the production of oil and gas properties in which the Company has an interest with joint partners, are recognize, on the basis of the Company's working interest in those properties (the entitlement method), on receipt of a statement of account from the operators of the properties.

Environmental and Site Restoration Costs

The Company recognizes an estimate of the liability associated with an asset retirement obligation ("ARO") in the financial statements at the time the liability is incurred. The estimated fair value of the ARO is recorded as a long-term liability with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a straight-line basis over the estimated life of the asset. The liability amount is increased each reporting period due to the passage of time and the amount of accretion to operations in the period. The ARO can also increase or decrease due to changes in the estimates of timing of cash flows or changes in the original estimated undiscounted cost. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded.

2. Significant Accounting Policies (cont'd)

Foreign Currencies

The functional and reporting currency of the Company is the Canadian dollar. Monetary assets and liabilities are translated at exchange rates in effect at the balance sheet date. Non-monetary assets are translated at exchange rates in effect when they were acquired. Revenue and expenses are translated at the approximate average rate of exchange for the year, except that amortization is translated at the rates used to translate related assets.

One of the Company's subsidiaries uses the US Dollar as the functional currency. However, this subsidiary is considered integrated to Eagleford Energy Inc's operations since it relies on the Company to fund its operations. Hence translation gains and losses of this subsidiary are charged to the consolidated statement of operations.

Marketable Securities

At each financial reporting period, the Company estimates the fair value of investments which are held-for-trading, based on quoted closing bid prices at the consolidated balance sheet dates or the closing bid price on the last day the security traded if there were no trades at the consolidated balance sheet dates and such valuations are reflected in the consolidated financial statements. The resulting values for unlisted securities whether of public or private issuers, may not be reflective of the proceeds that could be realized by the Company upon their disposition. The fair value of the securities at August 31, 2011 was $1 (2010 - $1) (see Note 6).

Financial Instruments

All financial instruments are measured at fair value on initial recognition of the instrument. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the applicable accounting standards.

Cash and cash equivalents are designated as "held-for-trading" and is measured at fair value, which approximates carrying value.

Marketable securities are designated as "held-for-trading" and measured at fair value with unrealized gains and losses recorded in net income until the security is sold or if an unrealized loss is considered other than temporary, the unrealized loss is expensed. Unrealized gains and losses represent the net difference between the total average costs of short term assets on hand and their fair value based on quoted market prices for the marketable securities.

Accounts receivable are designated as "loans and receivable" and are carried at amortized cost. Accounts payable and accrued liabilities, secured notes payable and shareholder loans are designated as "other financial liabilities" and are carried at amortized cost.

The CICA Handbook Section 3862 – "Financial Instruments – Disclosure", requires an entity to classify fair value measurements in accordance with an established hierarchy that prioritizes the inputs in valuation techniques used to measure fair value. The levels and inputs which may be used to measure fair value are as follows:

2. Significant Accounting Policies (cont'd)

Financial Instruments (cont'd)

Level 1 – fair values are based on quoted prices in active markets for identical assets or liabilities;

Level 2 – fair values are based on inputs other than quoted prices that are observable for the asset or liability, either directly (as prices) or indirectly (derived from prices); or

Level 3 – applies to assets and liabilities for inputs that are not based on observable market data, which are unobservable inputs.

Cash Equivalents

Cash equivalents include trust accounts, and term deposits with maturities of less than three months.

Estimates and Measurement Uncertainty

The preparation of the consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the values and presentation of assets, liabilities, revenues, expenses and disclosures of contingencies and commitments. Such estimates primarily relate to unsettled transactions and events at the balance sheet date which are based on information available to management at each financial statement date. Actual results may differ from those estimated.

Areas where management is required to make significant estimates are as follows:

i. Depletion and impairment of Oil and Gas Interests are determined using estimates for resource reserves, and the impairment assessment of Oil and Gas Interests requires further assumptions for future commodity prices, royalties, operating costs, development costs, abandonment costs, and the fair value of unproven properties, all of which are inherently uncertain. To mitigate the risk that inappropriate assumptions are used, estimates are evaluated by independent reserve evaluators.

ii. The provision for asset retirement obligations requires management to estimate the timing and amount of cash flows required to retire its Oil and Gas Interests.

iii. The Company uses the Black-Scholes option pricing model to determine the fair value of stock options and common share purchase warrants granted. This model requires management to estimate the volatility of the Company's future share price, expected lives of stock options and warrants and future dividend yields.

iv. The recognition of future income tax assets requires judgment as to whether future taxable income will be sufficient to realize the benefit of these tax assets.

By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the consolidated financial statements for current and future periods could be significant.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on temporary differences between financial reporting and tax bases of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes. Future income tax assets and liabilities are measured using substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. Future income tax assets are recognized in the financial statements if realization is considered more likely than not. A valuation allowance against future tax assets is provided to the extent that the realization of these future tax assets is not more likely than not.

Non-Monetary Transactions

Transactions in which shares or other non-cash consideration are exchanged for assets or services are measured at the fair value of the assets or services involved in accordance with Section 3831 ("Non-monetary Transactions") of the Canadian Institute of Chartered Accountants Handbook ("CICA Handbook").

Stock-Based Compensation

The Company follows a fair value based method of accounting for all Stock-based Compensation and Other Stock-based Payments to employees and non-employees. The fair value of all share purchase options is expensed over their vesting period with a corresponding increase to contributed surplus. Upon exercise of share purchase options, the consideration paid by the option holder, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital. The Company uses the Black-Scholes option valuation model to calculate the fair value of share purchase options at the date of grant.

The quoted market price of the Company's shares on the date of issuance under any stock compensation plan is considered as fair value of the shares issued.

Loss Per Share

Basic loss per share is calculated by dividing net loss (the numerator) by the weighted average number of common shares outstanding (the denominator) during the period. Diluted loss per share reflects the dilution that would occur if outstanding stock options and share purchase warrants were exercised or converted into common shares using the treasury stock method and are calculated by dividing net loss applicable to common shares by the sum of the weighted average number of common shares outstanding and all additional common shares that would have been outstanding if potentially dilutive common shares had been issued.

The inclusion of the Company's stock options and share purchase warrants in the computation of diluted loss per share would have an anti-dilutive effect on loss per share and are therefore excluded from the computation. Consequently, there is no difference between basic loss per share and diluted loss per share.

2. Significant Accounting Policies (cont'd)

Warrants

When the Company issues Units under a private placement comprising common shares and warrants, the Company follows the relative fair value method of accounting for warrants attached to and issued with common shares of the Company. Under this method, the fair value of warrants issued is estimated using a Black-Scholes option price model. The fair value is then related to the total of the net proceeds received on issuance of the Common shares and the fair value of the warrants issued therewith. The resultant relative fair value is allocated to warrants from the net proceeds and the balance of the net proceeds is allocated to the Common shares issued.

3. Change in Accounting Policies and Future Accounting Pronouncements

Change in Accounting Policies

Business Combinations

In January 2009, the CICA issued Section 1582, "Business Combinations", Section 1601, "Consolidations", and Section 1602, "Non-Controlling Interests". These sections replace the former Section 1581, "Business Combinations", and Section 1600, "Consolidated Financial Statements", and establish a new section for accounting for a non-controlling interest in a subsidiary.

Sections 1582 and 1602 will require net assets, non-controlling interests and goodwill acquired in a business combination to be recorded at fair value and non-controlling interests will be reported as a component of equity. In addition, the definition of a business is expanded and is described as an integrated set of activities and assets that are capable of being managed to provide a return to investors or economic benefits to owners. Acquisition costs are not part of the consideration and are to be expensed when incurred. Section 1601 establishes standards for the preparation of consolidated financial statements. The company will adopt these standards concurrently with IFRS.

Future Accounting Pronouncements

Adoption of International Financial Accounting Standards ("IFRS")

Public companies in Canada were required to adopt IFRS for the years beginning on or after January 1, 2011. For the company, the adoption date is September 1, 2011

Consequently, effective September 1, 2011, the Company adopted IFRS as the basis for preparing its consolidated financial statements.. The company will prepare its consolidated financial statements for the first quarter ending November 30, 2011 in accordance with IFRS, which will include comparative data for the prior year also prepared in accordance with IFRS as well as an opening IFRS balance sheet at September 1, 2010

The initial phase of implementation included conceptual application of the new rules, analysis of the Company's accounting data and assessment of key areas that may be impacted and a consideration of the exemptions allowed under IFRS1, first-time adoption of IFRS. In this phase, Property, Plant and Equipment, Exploration and Evaluation Assets, Impairment Testing and Asset Retirement Obligations were identified as key areas.

(Expressed in Canadian Dollars)

4. Business Acquisitions

2010 Acquisition
On August 31, 2010, Eagleford acquired 100% the issued and outstanding membership interests of Dyami Energy LLC, a Texas limited liability company ("Dyami Energy").The purchase price was satisfied by (i) the issuance of 3,418,467 units of the Company. Each unit is comprised of one common share and one-half a purchase warrant. Each full warrant is exercisable into one additional common share at US$1.00 per share on or before August 31, 2014 (the "Units"); and (ii) the assumption of US$960,000 of Dyami Energy debt by way of a secured promissory note. The note bears interest at 6% per annum, is secured by the Murphy and Matthews leases and is payable on the earlier of December 31, 2011 or upon the Company closing a financing or series of financings in excess of US$4,500,000.

The members of Dyami Energy entered into lock up/escrow agreements on closing and placed into escrow 50% of the Units (1,709,234 common shares and 854,617 purchase warrants) until such time that Company receives a National Instrument 51-101 compliant report from an independent engineering firm indicating at least 100,000 barrels of oil equivalent of proven reserves on either the Murphy Lease or any formation below the San Miguel on the Matthews Lease (the "Report"). In the event the Report is not received by Dyami Energy within two years of the closing date of the acquisition, the escrow units are returned to the Company for cancellation. In addition, without Eagleford's prior written consent, the members may not offer, sell, contract to sell, grant any option to purchase, hypothecate, pledge, transfer title to or otherwise dispose of any of the Units during the period commencing on August 31, 2010 and ending on August 31, 2011 (the "Lock-Up Period"). During the Lock-Up Period, the members may not effect or agree to effect any short sale or certain related transactions with respect to the Eagleford's common shares.

All US monetary considerations were exchanged at the date of acquisition using the Bank of Canada noon rate of $1.0639. Eagleford accounted for the transaction using the purchase method of accounting and as a result, the share capital and deficit of Dyami Energy are eliminated.

The fair value of the Dyami Energy transaction was approximately $4,218,812 (US$3,965,422) paid through the issuance of 3,418,467 Eagleford Units and the assumption and issuance of a $1,021,344 (US$960,000) secured promissory note. The purchase price allocation to the fair values of the assets and liabilities of Dyami Energy acquired as at August 31, 2010 was as follows:

Consideration:		
Issuance of 3,418,467 Eagleford units	$	4,218,812
Total consideration	$	4,218,812
Allocated to:		
Cash		5,369
Accounts receivable		11,371
Drilling advances		7,266
Prepaid expenses		16,060
Oil and gas interests		5,472,464
Accounts payable and accrued liabilities		(272,374)
Note payable		(1,021,344)
Net assets acquired	$	4,218,812
Incurred transaction costs:		
Financial advisory, legal and other expenses	$	35,581

(Expressed in Canadian Dollars)

4. Business Combinations (cont'd)

2009 Acquisition

On February 27, 2009, Eagleford acquired the issued and outstanding shares of 1354166 Alberta Ltd. ("1354166 Alberta") for total consideration of $445,528 satisfied by the issuance of 8,910,564 units of the Company at $0.05 per unit. Each unit consists of one common share and one common share purchase warrant exercisable at $0.07 to purchase one common share until February 27, 2014.

Following the closing, the Company paid to note holders of 1354166 Alberta the amount of $118,000 by cash payment. The acquisition was accounted for using the purchase method of accounting where the Company is identified as the acquirer. The purchase price allocation to the fair values of the assets and liabilities acquired as at February 27, 2009 was as follows:

Consideration:	
Issuance of 8,910,564 Eagleford units at $0.05 per unit	$ 445,528
Transaction costs	10,000
Total consideration	$ 455,528
Allocated to:	
Oil and gas interests	538,995
Notes payable and working capital deficit	(79,963)
Asset retirement obligation	(3,504)
Net assets acquired	$ 455,528
Incurred transaction costs:	
Financial advisory, legal and other expenses	$ 10,000

5. Accounts Receivable

The Company's accounts receivable balances at August 31, 2011 and 2010 are as follows:

	August 31, 2011	August 31, 2010
Trade receivables	$ 11,739	$ 55,797
HST receivable	43,275	23,935
Other receivables [1]	72,532	23,328
Allowance for doubtful accounts	-	-
Balance	$ 127,546	$ 53,060

(1) Included in other receivables are amounts due from joint interest partners.

6. Marketable Securities

	August 31, 2011	August 31, 2010
Investments in quoted companies		
(Fair value $1 (2010 - $1)	$ 1	$ 1

The Company holds securities of entities whose shares are listed on an exchange for trading. Accordingly, in prior years, management has written down the investments to a nominal value of $1. During the year, the Company sold one of its previously written down securities for gross proceeds of $8,000 (see Note 2).

(Expressed in Canadian Dollars)

7. Oil and Gas Interests

	August 31, 2011	August 31, 2010
Developed – Canada		
Net book value at	$ 314,000	$ 407,000
Change in asset retirement obligations estimate	1,600	-
Depletion	(23,136)	(38,370)
Impairment	(49,464)	(54,630)
Total developed, Alberta Canada	243,000	314,000
Undeveloped - USA		
Acquisition of a 10% interest in the Matthews Lease	212,780	212,780
Acquisition of oil and gas interests (Dyami Energy)	5,472,464	5,472,464
Exploration expenditures	10,046	10,046
Net book value at	5,695,290	5,695,290
Exploration expenditures	3,158,688	-
Asset retirement obligation	44,150	-
Total undeveloped, Texas, USA	8,898,128	5,695,290
Total developed and undeveloped	$ 9,141,128	$ 6,009,290

Developed -Canada

The Company has a 5.1975% interest in a producing natural gas unit located in the Botha area of Alberta, Canada. In addition the Company holds a 0.5% non convertible gross overriding royalty in a natural gas well located in the Haynes area of Alberta to which no reserves were assigned.

The Company performed an impairment test calculation at August 31, 2011 and 2010 using forecast prices and costs to assess the potential impairment of its developed oil and gas interests located in Canada. The oil and gas future prices are based on the commodity price forecast of the Company's independent reserve evaluators. At August 31, 2011 the Company recorded an impairment of $49,464 (2010 - $54,630).

Undeveloped – USA

The undeveloped properties have been excluded from the depletion base and have been assessed separately for impairment. No impairment allowance has been made during the year ended August 31, 2011 or 2010, based on management's best estimate of the fair value of the properties. Due to subjectivity related to their fair value assessments, by their nature such assessments are subject to measurement uncertainty.

Mathews Lease, Zavala County, Texas, USA

On June 14, 2010, Eagleford acquired a 10% working interest before payout and a 7.5% working interest after payout of production revenue of $15 million in a mineral lease comprising approximately 2,629 gross acres of land in Zavala County, Texas for consideration of $212,780.

7. Oil and Gas Interests (cont'd)

On August 31, 2010 the Company acquired all of the issued and outstanding membership interests of Dyami Energy, an exploration stage company. Dyami Energy holds a 75% working interest before payout and a 61.50% working interest after payout of production revenue of $12.5 million in the Matthews Lease, subject to the San Miguel formation farmout agreement noted below. The royalties payable under the Matthews Lease are 25%.

Dyami Energy acquired its interest in the Matthews Lease through a Purchase and Sale Agreement dated February 8, 2010 and amended October 15, 2010 (the "Agreement"). Under the terms of the Agreement, Dyami Energy had the following commitments:

(a) On or before August 23, 2010 Dyami Energy shall commence operations to drill an Initial Test Well on Matthews Lease to a depth of not less than 3,000 feet below the surface or to the base of the San Miguel "D" formation;

(b) On or before July 8, 2011, Dyami Energy shall commence operations to perform an injection operation (by use of steam, nitrogen or other) in the San Miguel formation on the Initial Test Well or any other well located on the Matthews Lease; and

(c) On or before January 1, 2011, Dyami Energy shall commence a horizontal well to test the Eagle Ford shale formation with a projected lateral length of not less than 2,500 feet (the "Second Test Well").

Dyami Energy's 15% working interest partner has an obligation to participate in each of the operations provided for in (a), (b) and (c) above and if the partner fails to bear its share of the costs of such operations, the partner shall forfeit its interest in and to the well and the applicable spacing unit.

In August 2010, Dyami Energy commenced operations to drill its Matthews/Dyami #1-H well to a measured depth of 8,563 feet including 3,300 horizontal feet into the Eagle Ford shale formation and accordingly Dyami Energy satisfied (a) and (c) above. The well has been logged and cored and the Company is formulating a detailed frac design and completion plan.

In order to satisfy (b) above on March 29, 2011 the Company spud the Matthews/Dyami #3 well and drilled to a vertical depth of approximately 3,500 feet to the base of the San Miguel formation. The Company completed a nitrified acid injection operation and the well has been placed on production testing.

On March 31, 2011 the Company entered into a Farmout Agreement (the "Farmout") from surface to the base of the San Miguel formation (the "San Miguel") on the Matthews Lease. Under the Farmout, the farmee may spend up to US$1,050,000 on exploration and development of the San Miguel to earn a maximum of 42.50% working interest (31.875% net revenue interest). Under the terms of the Farmout, the farmee may earn an initial 25% of the Company's working interest in the San Miguel by paying 100% of the costs to drill, complete, equip and perform an injection operation on a vertical test well to a depth of approximately 3,500 feet (the "Initial Test Well"). After the performance of the Initial Test Well, the farmee may increase its working interest to 50% of the Company's working interest by spending the entire $1,050,000 on additional operations on the San Miguel in a good faith effort to produce hydrocarbons. During the year ended August 31, 2011, the Company incurred $744,837 in costs related to the Matthews/Dyami #3 well and $71,871 is included in accounts receivable. As of August 31, 2011 the Company had not assigned any interest to the farmee in the San Miguel formation.

7. Oil and Gas Interests (cont'd)

Dyami Energy is the designated operator under the provisions of the Matthews Lease Operating Agreement.

The Matthews Oil and Gas Lease has a primary term of three years commencing April 12, 2008 and is now being held under a continuous drilling program provision which requires a well to be drilled every 180 days. Upon cessation of timely drilling, rights for further drilling expire on all acreage not included in a production unit which shall be re-assigned (see Note 19).

Murphy Lease, Zavala County, Texas, USA

Dyami Energy holds a 100% working interest in a mineral lease comprising approximately 2,637 acres of land in Zavala County, Texas (the "Murphy Lease") subject to a 10% carried interest on the drilling costs from surface to base of the Austin Chalk formation, and a 3% carried interest on the drilling costs from the top of the Eagle Ford shale formation to basement on the first well drilled into a serpentine plug and for the first well drilled into a second serpentine plug, if discovered. Thereafter Dyami Energy's working interests range from 90% to 97%. The royalties payable under the Murphy Lease are 25%.

Dyami Energy acquired its interest in the Murphy Lease through an Assignment Agreement dated effective February 3, 2010 (the "Assignment"). The Murphy Oil and Gas Mineral Lease ("Mineral Lease Agreement') has a primary term of three years commencing on February 2, 2010. Under the terms of the Assignment and the Mineral Lease Agreement, Dyami Energy had a commitment to spud a well to a depth to sufficiently test the Eagle Ford Shale formation by August 3, 2010 or pay a lease delay payment of US $25 per acre totaling US$65,925 in the aggregate (paid July 28, 2010) to extend the period to commence drilling for 180 days to January 30, 2011. On January 20, 2011, Dyami Energy spud its Murphy/Dyami #1 test well and drilled to a vertical depth of approximately 4,588 feet and accordingly satisfied this commitment.

Dyami Energy is required to drill a well every six months in order to maintain the Murphy Lease. Upon cessation of timely drilling, rights for further drilling expire on all acreage not included in a production unit which shall be re-assigned (see Note 19).

On July 30, 2011 Dyami Energy spud its second test well the Murphy/Dyami #2 and drilled to a vertical depth of approximately 4,415 feet. The Company is formulating completion programs for the Murphy/Dyami #1 and Murphy/Dyami #2 wells.

(Expressed in Canadian Dollars)

8. Asset Retirement Obligations

The Company's asset retirement obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations at August 31, 2011 was approximately $102,974 which will be incurred between 2022 and 2030 (2010 - $8,568). A credit-adjusted risk-free rate of 7% and an annual inflation rate of 3.9% were used to calculate the future asset retirement obligation.

	2011	2010
Balance, beginning of year	$ 3,907	$ 3,634
Additions	44,150	-
Accretion expense	551	273
Change in estimates	1,600	-
	$ 50,208	$ 3,907

9. Share Capital and Contributed Surplus

Authorized:
Unlimited number of common shares
Unlimited non-participating, non-dividend paying, voting redeemable preference shares

Issued:

Common Shares	Number	Amount
Balance at August 31, 2008	10,471,739	$ 467,604
February 5, 2009 private placement (note a)	2,600,000	67,600
February 25, 2009 private placement (note b)	1,000,256	26,007
February 27, 2009 acquisition (note c)	8,910,564	231,675
February 27, 2009 debt settlement (note d)	1,250,000	32,500
Balance at August 31, 2009	24,232,559	825,386
Exercise of warrants (note e)	2,100,000	197,400
August 31, 2010 acquisition, net of transaction costs (note f)	3,418,467	2,794,398
Balance August 31, 2010	29,751,026	3,817,184
Exercise of warrants (note h)	3,710,346	722,572
Issued as compensation (note i)	100,000	95,800
Balance August 31, 2011	33,561,372	$ 4,635,556

(a) On February 5, 2009, the Company completed a non-brokered private placement of 2,600,000 units at a purchase price of $0.05 per unit for gross proceeds of $130,000. Each unit was comprised of one common share and one common share purchase warrant. Each warrant is exercisable until February 5, 2014, to purchase one common share at a purchase price of $0.07 per share. The amount allocated to warrants based on relative fair value using Black Scholes model was $62,400.

(b) On February 25, 2009, the Company completed a non-brokered private placement of 1,000,256 units at a purchase price of $0.05 per unit for gross proceeds of approximately $50,013. Each unit was comprised of one common share and one common share purchase warrant. Each warrant is exercisable until February 25, 2014 to purchase one common share at a purchase price of $0.07 per share. The amount allocated to warrants based on relative fair value using Black Scholes model was $24,006.

9. Share Capital and Contributed Surplus (cont'd)

(c) On February 27, 2009, the Company acquired the issued and outstanding shares of 1354166 Alberta for total consideration of $445,528 satisfied by the issuance of 8,910,564 units of the Company at $0.05 per unit. Each unit consists of one common share and one common share purchase warrant exercisable at $0.07 to purchase one common share until February 27, 2014. The amount allocated to warrants based on relative fair value using Black Scholes model was $213,853.

(d) On February 27, 2009, the Company entered into an agreement with a non-related party, to settle debt in the amount of $62,500 through the issuance of a total of 1,250,000 units at an attributed value of $0.05 per unit. Each unit was comprised of one common share and one common share purchase warrant. Each warrant is exercisable until February 27, 2014 to purchase one common share at a purchase price of $0.07 per share. The amount allocated to warrants based on relative fair value using Black Scholes model was $30,000.

(e) During the year ended August 31, 2010, 1,100,000 warrants were exercised at $0.07 expiring February 5, 2014 for proceeds of $77,000 and 1,000,000 warrants were exercised at $0.07 expiring February 27, 2014 for proceeds of $70,000. The amount allocated to warrants based on relative fair value using Black Scholes model was $50,400.

(f) On August 31, 2010, the Company acquired all of the issued and outstanding membership interests of Dyami Energy and issued 3,418,467 units of the Company. Each unit consists of one common share and one half a common share purchase warrant. Each full warrant is exercisable at US$1.00 to purchase one common share until August 31, 2014. The fair value of the acquisition was estimated to be $4,218,812. Transaction costs of $35,581 were recorded as a reduction to share capital. The amount allocated to warrants based on relative fair value using Black Scholes model was $1,388,833.

(g) Effective June 10, 2010, the Company retained Gar Wood Securities, LLC ("Gar Wood") to act as Investment Banker/Financial Advisor to the Company for a period of two years. Under the terms of the Gar Wood engagement, the Company agreed to pay a fee of 6% of the gross proceeds raised and issue 1,500,000 common share purchase warrants (the "Warrants") as follows:

1,000,000 Warrants are exercisable at US$1.00 to purchase 1,000,000 common shares expiring on December 10, 2011 and issuable in three equal tranches on June 10, 2010, December 10, 2010 and June 10, 2011; and 500,000 Warrants are exercisable at US$1.50 to purchase 500,000 common shares expiring on June 10, 2012 and issuable in three equal tranches on June 10, 2010, December 10, 2010 and June 10, 2011. The amount allocated to warrants based on relative fair value using the Black Scholes model was $214,372 and $112,139 respectively and the total, $326,511 was recorded as compensation expense.

On November 5, 2010, the Company terminated the agreement dated June 10, 2010 with Gar Wood. As a result 36,430 warrants exercisable at $1.00 expiring December 10, 2011 were cancelled and 18,215 warrants were exercisable at $1.50 expiring June 10, 2012 were cancelled. The amount allocated to warrants based on relative fair value using the Black Scholes model was $23,315 and $12,204 respectively and the total, $35,519 was recorded as an increase to contributed surplus.

EAGLEFORD ENERGY INC

Notes to Consolidated Financial Statements
(Expressed in Canadian Dollars)
For the years ended August 31, 2011, 2010 and 2009

9. Share Capital and Contributed Surplus (cont'd)

(h) During the year ended August 31, 2011, 500,000 common share purchase warrants were exercised at $0.07 expiring February 5, 2014 for proceeds of $35,000. The amount allocated to warrants based on relative fair value using the Black Scholes model was $12,000; 600,000 common share purchase warrants were exercised at $0.07 expiring February 25, 2014 for proceeds of $42,000. The amount allocated to warrants based on relative fair value using the Black Scholes model was $14,400; 35,346 common share purchase warrants were exercised at $0.07 expiring February 27, 2014 for proceeds of $2,475. The amount allocated to warrants based on relative fair value using the Black Scholes model was $822; and 2,575,000 common share purchase warrants were exercised at $0.20 expiring April 14, 2011 for proceeds of $515,000. The amount allocated to warrants based on relative fair value using the Black Scholes model was $100,875.

(i) On April 29, 2011, the Company entered into a consulting agreement with a service provider to provide corporate marketing and public relations to the Company for a period of six months. As compensation, the Company agreed to issue 100,000 common shares and 50,000 common share purchase warrants exercisable at US $1.25 per common share expiring May 4, 2012. The amount allocated to common shares was based on the share price at the time of issuance, amounting to $95,800 and $37,054 for the warrants based on the estimated fair value using the Black Scholes pricing model. $88,569 was recorded as marketing and public relations expense and $44,285 was recorded as prepaid expenses at August 31, 2011.

The following table summarizes the changes in warrants for the years then ended:

	2011		2010		2009	
Warrants	Number of Warrants	Weighted Average Price	Number of Warrants	Weighted Average Price	Number of Warrants	Weighted Average Price
Outstanding beginning of year	16,445,053	$ 0.22	16,335,820	$ 0.09	2,575,000	$ 0.20
Issued	50,000	1.25	2,209,233	1.04	13,760,820	0.07
Exercised	(2,575,000)	0.20	(2,100,000)	0.07	-	-
Exercised	(1,113,346)	0.07	-	-	-	-
Cancelled	(36,430)	1.00	-	-	-	-
Cancelled	(18,215)	1.50	-	-	-	-
Outstanding end of year	12,730,062	$ 0.24	16,445,053	$ 0.22	16,335,820	$ 0.09

The following table summarizes the outstanding warrants as at August 31, 2011:

Number of Warrants	Note	Exercise Price		Expiry Date	Warrant Value ($)
1,000,000	(note a, e, h)	$	0.07	February 5, 2014	$ 24,000
400,256	(note b, h)	$	0.07	February 25, 2014	9,606
9,125,218	(note c, d, e, h)	$	0.07	February 27, 2014	219,031
296,903	(note g)	US$	1.00	December 10, 2011	191,057
148,452	(note g)	US$	1.50	June 10, 2012	99,935
1,709,233	(note f)	US$	1.00	August 31, 2014	1,388,833
50,000	(note i)	US$	1.25	May 4, 2012	37,054
12,730,062					$ 1,969,516

(Expressed in Canadian Dollars)

9. Share Capital and Contributed Surplus (cont'd)

The fair value of the warrants issued during the year ended August 31, 2011, 2010 and 2009 were estimated on the date of issue using the Black-Scholes pricing model with the following assumptions:

Black-Scholes Assumptions used		2011
Risk-free interest rate		1.7%
Expected volatility		254%
Expected life (years)		1
Dividend yield		0%
Fair value of the warrants issued on May 4, 2011	$	0.74

Black-Scholes Assumptions used		2010
Risk-free interest rate		3%
Expected volatility		234%
Expected life (years)		4
Dividend yield		0%
Fair value of the warrants issued on June 10, 2010	$	0.65
Fair value of the warrants issued on August 31, 2010	$	0.81

Black-Scholes Assumptions used		2009
Risk-free interest rate		3%
Expected volatility		170%
Expected life (years)		4
Dividend yield		0%
Fair value of the warrants issued on February 5, 2009	$	0.05
Fair Value of the warrants issued on February 25, 2009	$	0.05
Fair Value of the warrants issued on February 27, 2009	$	0.05

The weighted average basic and diluted shares outstanding at August 31, 2011, 2010 and 2009 is as follows:

Weighted Average Shares Outstanding	2011	2010	2009
Weighted average shares outstanding, basic	31,927,228	24,687,130	17,646,295
Dilutive effect of warrants	13,273,114	16,008,996	9,749,557
Weighted average shares outstanding, diluted	45,200,342	40,696,126	27,395,852

The effects of any potential dilutive instruments on loss per share related to the outstanding warrants are anti-dilutive and therefore have been excluded from the calculation of diluted loss per share.

Stock Option Plan

The Company has a stock option plan to provide incentives for directors, officers and consultants of the Company. The maximum number of shares, which may be set aside for issuance under the stock option plan, is 6,170,205 common shares. To date, no options have been issued.

(Expressed in Canadian Dollars)

9. Share Capital and Contributed Surplus (cont'd)

Contributed Surplus

Contributed surplus transactions for the respective years are as follows:

		Amount
Balance, August 31, 2008 and 2009	$	38,000
Imputed interest		5,750
Balance, August 31, 2010		43,750
Cancellation of warrants (note g)		35,519
Imputed interest (see Note 10)		5,750
Balance, August 31,2011	$	85,019

10. Related Party Transactions and Balances

The following transactions with an individual related to the Company arose in the normal course of business have been accounted for at the exchange amount being the amount agreed to by the related parties, which approximates the arm's length equivalent value.

	2011	2010 (1)	2009 (1)
Management fees to the President and Director of the Company	$ 56,250	$ 24,000	$ 18,000

(1) Management fees to the former President of the Company.

At August 31, 2011 included in accounts payable are management fees payable to the President of $56,250 (2010 – Nil).

At August 31, 2011 the amount of directors' fees included in accounts payable was $8,800 (2010 - $6,700).

On February 5, 2009, a corporation in which the Company's former President has voting and significant investment interest, acquired 1,600,000 Units at a price of $0.05 per unit. Each unit was comprised of one common share and one common share purchase warrant. Each warrant is exercisable until February 5, 2014, to purchase one common share at a purchase price of $0.07 per share.

On February 25, 2009, the Company's former President acquired 600,000 Units at a price of $0.05 per Unit. Each unit was comprised of one common share and one common share purchase warrant. Each warrant is exercisable until February 25, 2014 to purchase one common share at a purchase price of $0.07 per share.

On February 25, 2009, a director of the Company acquired 50,000 Units at a price of $0.05 per Unit. Each unit was comprised of one common share and one common share purchase warrant. Each warrant is exercisable until February 25, 2014 to purchase one common share at a purchase price of $0.07 per share.

10. Related Party Transactions and Balances (cont'd)

On February 27, 2009, Eagleford acquired the issued and outstanding shares of 1354166 Alberta for total consideration of $445,528 satisfied by the issuance of 8,910,564 units of the Company at $0.05 per unit. Following the closing, the Company paid to note holders of 1354166 Alberta the amount of $118,000 by cash payment.

At August 31, 2010 the Company issued a US$175,000, 5% per annum secured promissory note to Source Re Work Program, Inc. ("Source"). On March 18, 2011 the Company re-paid to Source US$100,000 of the promissory note. Eric Johnson is the President of Source, a shareholder of the Company and was the Vice President of Operations for Dyami Energy until April 13, 2011. During the year ended August 31, 2011, the Company paid to Eric Johnson expenses of US$5,506 and salary of US$43,750 (see Note 12 and Note 19).

At August 31, 2011 the Company has a US$960,000, 6% per annum secured promissory note payable to Benchmark Enterprises LLC ("Benchmark"). Benchmark is a shareholder of the Company. For the year ended August 31, 2011 interest of $55,356 was recorded and included in accounts payable (August 31, 2010 - $26,863) (see Note 12).

At August 31, 2011 included in accounts payable is $68,918 due to Gottbetter & Partners LLP for legal fees (August 31, 2010 - $82,154). Gottbetter Capital Group, Inc. is a shareholder of the Company. Adam Gottbetter is sole owner of Gottbetter & Partners LLP and Gottbetter Capital Group, Inc.

The loan payable of $57,500 is due to a shareholder and is unsecured, non-interest bearing and repayable on demand. For the year ended August 31, 2011 interest was imputed at a rate of 10% per annum and interest of $5,750 was recorded and included in contributed surplus (August 31, 2010 - $5,750).

During the year ended August 31, 2011, the Company received US$2,490,000 and $149,000 and issued promissory notes to seven shareholders. The notes are payable on demand and bear interest at 10% per annum. Interest is payable annually on the anniversary date of the notes. At August 31, 2011 accrued interest of $171,640 is included in accounts payable.

During the year ended August 31, 2011, Company received US$300,000 and issued a promissory note to the President of the Company. The note is due on demand and bears interest at 10% per annum. Interest is payable annually on the anniversary date of the note. For the year ended August 31, 2011 interest of $26,135 was recorded and included in accounts payable (see Note 19).

11. Loan Payable

The loan payable in the amount of $110,000 was due to an arms' length 3 rd party and was unsecured, non-interest bearing and repayable on demand. On May 4, 2011 the Company repaid the demand loan in full.

(Expressed in Canadian Dollars)

12. Secured Notes Payable

On August 31, 2010 the Company issued a US$175,000, 5% per annum secured promissory note to Source Re Work Program, Inc. ("Source"). The note was secured by the Eagleford's interest in the Matthews Lease, Zavala County, Texas. US$100,000 of the note was due on February 28, 2011 and was repaid on March 18, 2011. The balance of US$75,000 (CDN $73,380) of the note together with accrued interest is due and payable on August 31, 2011. For the year ended August 31, 2011 interest of $6,115 was recorded and included in accounts payable (see Note 19).

At August 31, 2011 the Company has a US$960,000 (2011 CDN $939,264), 6% per annum secured promissory note payable to Benchmark Enterprises LLC (August 31, 2010 US960,000). The note is payable on the earlier of December 31, 2011 or upon the Company closing a financing or series of financings in excess of US$4,500,000. For the year ended August 31, 2011 interest of $56,356 was recorded and included in accounts payable (August 31, 2010 $26,863). The note is secured by Dyami Energy's interest in the Matthews and Murphy Leases, Zavala County, Texas. The Company may, in its sole discretion, repay any portion of the principal amount (see Note 10).

13. Segmented Information

The Company's only segment is oil and gas exploration and production and includes two geographic areas, Canada and the United States. The accounting policies applied to Eagleford's operating segments are the same as those described in the summary of significant accounting policies.

Geographic information:

The following is segmented information as at and for the year ended August 31, 2011:

	Year ended August 31, 2011		As at August 31, 2011	
	Interest and other income	Net (loss)	Oil and gas interests	Other assets
Canada	$ 71,786	$ (696,643)	$ 243,000	$ 264,611
United States	-	(55,914)	8,898,128	72,487
Total	$ 71,786	$ (752,557)	$ 9,141,128	$ 337,098

The following is segmented information as at and for the year ended August 31, 2010:

	Year ended August 31, 2010		As at August 31, 2010	
	Interest and other income	Net (loss)	Oil and gas interests	Other assets
Canada	$ 105,404	$ (688,709)	$ 314,000	$ 68,141
United States	-	-	5,695,290	30,021
Total	$ 105,404	$ (688,709)	$ 6,009,290	$ 98,162

14. Financial Instruments and Concentration of Risks

The Company is exposed in varying degrees of risks arising from financial its instruments. The Company does not participate in the use of derivative financial instruments to mitigate these risks and has no designated hedging transactions. The Board approves and monitors the risk management processes. The Board's main objectives for managing risks are to ensure liquidity, the fulfillment of obligations and limited exposure to credit and market risks while ensuring greater returns on any surplus funds -. There were no changes to the objectives or the process from the prior year. Cash and cash equivalents and marketable securities are the only financial instruments and are classified as level 1 financial instruments in the fair value hierarchy.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective April 1, 2009, the Company adopted the recommendations of the Emerging Issues Committee Abstract EIC -173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities" which states that an entity's own credit and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities. These recommendations were particularly applied in evaluating the fair values of the Company's marketable securities.

The types of risk exposure and the ways in which such exposures are managed are as follows:

Credit Risk

Concentration risks exist in cash and cash equivalents because significant balances are maintained with one financial institution and a brokerage firm. The risk is mitigated because the financial institution is an international bank and the brokerage firm is a reputable Canadian brokerage firm.

Liquidity Risk

The Company monitors its liquidity position regularly to assess whether it has the funds necessary to fulfill planned exploration commitments on its oil and gas properties or that viable options are available to fund such commitments from new equity issuances or alternative sources such as farm-out agreements. However, as an exploration company at an early stage of development and without significant internally generated cash flow, there are inherent liquidity risks, including the possibility that additional financing may not be available to the Company, or that actual exploration expenditures may exceed those planned. The current uncertainty in global markets and ongoing litigations could have an impact on the Company's future ability to access capital on terms that are acceptable to the Company. The Company has so far been able to raise the required financing to meet its obligation on time.

Market Risk

Market risk represents the risk of loss that may impact our financial position, results of operations, or cash flows due to adverse changes in financial market prices, including interest rate risk, foreign currency exchange rate risk, commodity price risk, and other relevant market or price risks. The Company does not use derivative financial instruments or derivative commodity instruments to mitigate this risk.

(Expressed in Canadian Dollars)

14. Financial Instruments and Concentration of Risks (cont'd)

The oil and gas industry is exposed to a variety of risks including the uncertainty of finding and recovering new economic reserves, the performance of hydrocarbon reservoirs, securing markets for production, commodity prices, interest rate fluctuations, potential damage to or malfunction of equipment and changes to income tax, royalty, environmental or other governmental regulations.

Market events and conditions in recent years including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions have caused significant volatility to commodity prices. These conditions caused a loss of confidence in the broader U.S. and global credit and financial markets. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and may impact the performance of the global economy going forward. Although economic conditions improved towards the latter portion of 2009, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

The Company mitigates these risks by:

- utilizing competent, professional consultants as support teams to company staff.
- performing geophysical, geological or engineering analyses of prospects.
- focusing on a limited number of core properties.

(i) Commodity Price Risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand.

The Company believes that movement in commodity prices that are reasonably possible over the next twelve month period will not have a significant impact on the Company.

Commodity Price Sensitivity

The following table summarizes the sensitivity of the fair value of the Company's risk management position for the year ended August 31, 2011 and 2010 to fluctuations in natural gas prices, with all other variables held constant. When assessing the potential impact of these price changes, the Company believes that 10 percent volatility is a reasonable measure. Fluctuations in natural gas prices potentially could have resulted in unrealized gains (losses) impacting net income as follows:

	2011		2010	
	Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
Revenue	$ 78,965	$ 64,607	$ 115,911	$ 94,837
Net loss	$ (745,378)	$ (759,736)	$ (678,172)	$ (699,246)

14. Financial Instruments and Concentration of Risks (cont'd)

(ii) Currency Risk

The Company is exposed to the fluctuations in foreign exchange rates. The prices received by the Company for the production of natural gas and natural gas liquids are primarily determined in reference to United States dollars but are settled with the Company in Canadian dollars. The Company's cash flow for commodity sales will therefore be impacted by fluctuations in foreign exchange rates.

The Company operates in Canada and a portion of its expenses are incurred in U.S. dollars. A significant change in the currency exchange rates between the CDN dollar relative to US dollar could have an effect on the Company's results of operations, financial position or cash flows.

The Company is exposed to currency risk through the following assets and liabilities denominated in US dollars at August 31, 2011 and 2010:

Financial Instruments	2011	2010
Cash and cash equivalents	$ 117,383	$ 5,046
Accounts receivable	72,487	21,926
Due from related party	-	1,245
Accounts payable	656,401	198,015
Shareholder loans	2,790,000	-
Secured notes payable	1,035,000	1,135,000
Total US$	$ 4,671,271	$ 1,361,232
CDN dollar equivalent at year end (1)	$ 4,570,372	$ 1,448,215

(1) Translated at the exchange rate in effect at August 31, 2011 $0.9784 (August 31, 2010 - $1.0639)

For the year ended August 31, 2011 the Company had a foreign exchange gain of $164,800 due to the fluctuations in the CDN dollar compared to the US dollar. For the year ended August 31, 2011 a 1% increase/decrease in the exchange rate is estimated to give rise to a change in net loss and comprehensive loss of approximately $1,904. The Company does not use derivative financial instruments to reduce its foreign exchange exposure.

(iii) Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. The majority of the Company's debt is short-term in nature with fixed rates.

Based on management's knowledge and experience of the financial markets, the Company believes that the movements in interest rates that are reasonably possible over the next twelve month period will not have a significant impact on the Company.

(Expressed in Canadian Dollars)

15. Capital Management

The Company's objectives when managing capital are to ensure the Company will have sufficient financial capacity, liquidity and flexibility to funds its operations, growth and ongoing exploration and development commitments on its oil and gas interests. The Company is dependent on funding these activities through debt and equity financings. Due to long lead cycles of the Company's exploration activities, the Company's capital requirements currently exceed its operation cash flow generated. As such the Company is dependent upon future financings in order to maintain its flexibility and liquidity and may from time to time be required to issue equity, issue debt, adjust capital spending or seek joint venture partners.

The Company manages the capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of any underlying assets in order to meet current and upcoming obligations. Current plans for the development commitments of the Company's Texas leases include debt or equity financing or seeking and obtaining a joint venture partner.

The board of directors does not establish quantitative return on capital criteria for management, but rather relies on the expertise of the Company's management and favourable market conditions to sustain future development of the business.

As at August 31, 2011and 2010 the Company considers its capital structure to comprise of shareholders equity and long-term debt.

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Company, is reasonable.

There were no changes in the Company's capital management during the period ended August 31, 2011.

The Company is not subject to any externally imposed restrictions on its capital requirements.

16. Income Taxes

The Company has capital losses in the amount of approximately $195,852 (2010 - $195,852) which may be carried forward indefinitely to offset future capital gains, and non capital losses in the amount of approximately $1,349,189 (2010 - $794,304) available for carry forward purposes. The non-capital losses expire as follows:

2014	$ 46,501
2015	47,434
2026	55,415
2027	42,337
2028	49,166
2029	264,244
2030	286,991
2031	557,101
	$ 1,349,189

(Expressed in Canadian Dollars)

16. Income Taxes (cont'd)

A reconciliation between income taxes provided at actual rates and at the basic rate ranging from 28% to 31% (2010 - 28% to 31%) (2009 - 25% to 29%) for federal and provincial taxes is as follows:

	2011	2010	2009
Taxes at statutory rates	$ (225,259)	$ (203,169)	$ (88,792)
Non-taxable items and others	81,421	154,677	47,326
Change in valuation allowance	143,838	48,492	41,466
	$ -	$ -	$ -

The significant components of the Company's future tax asset are summarized as follows:

	2011	2010
Operating loss carry forwards	$ 337,297	$ 198,576
Share issue costs	6,119	11,959
Marketable securities	1,467	1,467
Capital losses carry forwards	24,482	24,482
Oil and gas interests	29,016	17,939
Cumulative eligible capital	1,319	1,418
Future tax asset	399,700	255,841
Valuation allowance	(399,700)	(255,841)
	$ -	$ -

The Company has provided a full valuation allowance against future tax assets at August 31, 2011, due to uncertainties in the Company's ability to utilize its net operating losses.

17. Reconciliation to Accounting Principles Generally Accepted in the United States

These consolidated financial statements have been prepared in accordance with "Canadian GAAP". Material variations in the accounting principles, practices and methods used in preparing these consolidated financial statements from "US GAAP" and in SEC Regulation S-X are described and quantified below.

The significant differences between Canadian GAAP and US GAAP which had any impact on the consolidated balance sheet and consolidated statement of cash flows are noted below.

Oil and Gas Interests

In applying the successful efforts method under US GAAP (Regulation S-X Article 4-10), the Company performs a ceiling test based on the same calculations used for Canadian GAAP except the Company is required to discount future net revenues from proved reserves at 10% as opposed to utilizing the fair market value and probable reserves are excluded. During the year an impairment loss of $219,464 (2010-$104,630) for US GAAP and an impairment loss of $49,464 (2010-$54,630) was recorded for Canadian GAAP.

(Expressed in Canadian Dollars)

17. Reconciliation to Accounting Principles Generally Accepted in the United States (cont'd)

If US GAAP was followed, the effect on the consolidated balance sheet would be as follows:

	2011	2010
Total assets according to Canadian GAAP	$ 9,478,226	$ 6,107,452
Additional impairment of oil and gas interests	(170,000)	(50,000)
Total assets according to US GAAP	$ 9,308,226	$ 6,057,452

	2011	2010
Total shareholders' equity according to Canadian GAAP	$ 4,220,299	$ 4,239,777
Deficit adjustment per US GAAP		
Additional impairment of oil and gas interests	(170,000)	(50,000)
Total shareholders' equity according to US GAAP	$ 4,050,299	$ 4,189,777

If US GAAP was followed, the effect on the consolidated statements of loss and comprehensive loss would be as follows:

	2011	2010	2009
Net loss according to Canadian GAAP	$ 752,557	$ 688,709	$ 328,861
Add: Additional impairment of oil and gas interests	170,000	50,000	73,638
Net loss according to US GAAP	$ 922,557	$ 738,709	$ 402,499
Loss per share, basic and diluted	$ (0.029)	$ (0.030)	$ (0.023)
Shares used in the computation of loss per share	31,927,228	24,687,130	17,646,295

Adoption of New Accounting Policies

FASB Accounting Standards Update ("ASU") No. 2010-13 was issued in April 2010, and amends and clarifies ASC 718 with respect to the classification of an employee share based payment award with an exercise price denominated in the currency of a market in which the underlying security trades. This ASU did not have a material effect on the Company.

In April 2010, the FASB issued ASU 2010-14, "Accounting for Extractive Activities — Oil & Gas". ASU 2010-14 amends paragraph 932-10-S99-1 due to SEC Release No. 33-8995, "Modernization of Oil and Gas Reporting." The amendments to the guidance on oil and gas accounting are effective August 31, 2010, and did not have a significant impact on the Company's financial position that, if it is unable to raise additional capital, it may find it necessary to substantially reduce or cease operations.

17. Reconciliation to Accounting Principles Generally Accepted in the United States (cont'd)

Future Accounting Pronouncements

In January 2010, FASB issued ASU 2010-06 "Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurement" was issued, which provides amendments to Subtopic 820-10 that requires new disclosures as follows:

1. Transfers in and out of Levels 1 and 2. A reporting entity should disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers.
2. Activity in Level 3 fair value measurements. In the reconciliation for fair value measurements using significant unobservable inputs (Level 3), a reporting entity should present separately information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than as one net number).

This Update provides amendments to Subtopic 820-10 that clarify existing disclosures as follows:

1. Level of disaggregation. A reporting entity should provide fair value measurement disclosures for each class of assets and liabilities. A class is often a subset of assets or liabilities within a line item in the statement of financial position. A reporting entity needs to use judgment in determining the appropriate classes of assets and liabilities.
2. Disclosures about inputs and valuation techniques. A reporting entity should provide disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements. Those disclosures are required for fair value measurements that fall in either Level 2 or Level 3.

This Update also includes conforming amendments to the guidance on employers' disclosures about postretirement benefit plan assets (Subtopic 715-20). The conforming amendments to Subtopic 715-20 change the terminology from major categories of assets to classes of assets and provide a cross reference to the guidance in Subtopic 820-10 on how to determine appropriate classes to present fair value disclosures. The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years.

In December 2010, the FASB issued ASU 2010-28 "Intangibles – Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test For Reporting Units With Zero or Negative Carrying Amounts" ("ASU 2010-28").Under ASU 2010-28, if the carrying amount of a reporting unit is zero or negative, an entity must assess whether it is more likely than not that goodwill impairment exists. To make that determination, an entity should consider whether there are adverse qualitative factors that could impact the amount of goodwill, including those listed in ASC 350-20-35-30. As a result of the new guidance, an entity can no longer assert that a reporting unit is not required to perform the second step of the goodwill impairment test because the carrying amount of the reporting unit is zero or negative, despite the existence of qualitative factors that indicate goodwill is more likely than not impaired. ASU 2010-28 is effective for public entities for fiscal years, and for interim periods within those years, beginning after December 15, 2010, with early adoption prohibited.

17. Reconciliation to Accounting Principles Generally Accepted in the United States (cont'd)

Future Accounting Pronouncements (cont'd)

In December 2010, the FASB issued ASU 2010-29 "Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations" ("ASU 2010-29"). ASU 2010-29 specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments in this Update also expand the supplemental pro forma disclosures under Topic 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amended guidance is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Early adoption is permitted.

In April 2011, the FASB issued ASU No. 2011-02, A Creditor's Determination of Whether a Restructuring Is a Troubled Debt Restructuring, as codified in ASC 310, Receivables. The amendments in this update provide additional guidance to assist creditors in determining whether a restructuring of a receivable meets the criteria to be considered a troubled debt restructuring. The amendments in this update are effective for the period beginning on or after June 15, 2011, and should be applied retrospectively to the beginning of the annual period of adoption. The Company does not expect this update to have a material impact on its consolidated financial statements.

The Company will transition to IFRS on September 1, 2011 and will no longer be required to prepare a reconciliation to US GAAP. Accordingly, the Company has not assessed the impact of adopting future US accounting pronouncements with an application date of September 1, 2011 or beyond in its financial statements and disclosures (see Note 3).

18. Commitments and Contingencies

The Company has drilling commitments on its Mathews Lease and Murphy Lease located in Zavala County, Texas, USA (see Note 7).

Subsequent to the year ended August 31, 2011, a vendor of Dyami Energy has filed a claim in the District Court of Harris County, Texas seeking payment of US$62,800. Dyami Energy is disputing the claim on the basis of excessive charges. The full amount of the claim has been recorded in accounts payable and the outcome of this claim is uncertain at this time. Any legal costs will be expensed as incurred.

(Expressed in Canadian Dollars)

EAGLEFORD ENERGY INC

19. Subsequent Events

On September 1, 2011 the Company repaid to Source, the secured promissory note in full in the amount of US$75,000 together with accrued interest of US$6,250.

Subsequent to the year ended August 31, 2011, the Company commenced drilling its Matthews/Dyami #2H well located in Zavala County, Texas.

Subsequent to the year ended August 31, 2011, the Company issued 639,297 common shares to promissory note holders as full settlement of interest due in the amount of US$166,000 and CDN$14,900.

Subsequent to the year ended August 31, 2011, the Company received $198,845 and US$165,000 and issued promissory notes to five shareholders of the Company. The notes are due on demand and bear interest at 10% per annum. Interest is payable annually on the anniversary date of the note.

20. Supplemental Cash Flow Information and Non-cash Transactions

The following table summarizes the non-cash transactions for the years ended August 31:

	2011	2010	2009
Issuance of shares and warrants for services	$ 88,569	$ 326,511	-
Acquisition of subsidiary	-	4,213,443	$ 445,528
Issuance of units on acquisition of subsidiary	-	(4,213,443)	(445,528)
Transaction costs	-	35,581	-
Warrants cancelled	(35,519)	-	-
Secured notes payable-Long term	-	1,021,344	-
Secured notes payable-Current	-	186,183	-
Shares issued to settle debt		-	62,500
Prepaid portion of shares for services	44,285	-	-

The following table summarizes the supplemental cash flow information for the years ended August 31:

Supplemental cash flow information	2011	2010	2009
Income taxes paid	$ -	$ 10,215	$ -
Interest paid	-	-	-

The following table summarizes the changes in non-cash working capital for the years ended August 31:

	2011	2010	2009
Accounts receivable	$ (74,486)	$ (9,312)	$ (9,297
Accounts payable	770,098	63,382	33,252
Due from related party	1,325	-	-
Income taxes payable	-	(10,215)	-
Net change	$ 696,937	$ 43,855	$ 23,955

21. Comparative Figures

Certain comparative figures have been reclassified to conform to the presentation adopted in 2011.

22. Seasonality and Trend Information

The Company's oil and gas operations is not a seasonal business, but increased consumer demand or changes in supply in certain months of the year can influence the price of produced hydrocarbons, depending on the circumstances. Production from the Company's oil and gas properties is the primary determinant for the volume of sales during the year.

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

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers conduct active exploration programs. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

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

INDEX TO EXHIBITS

1.1*	Certificate of Incorporation of Bonanza Red Lake Explorations Inc. (presently known as Eagleford Energy Inc.) dated September 22, 1978
1.2*	Articles of Amendment dated January 14, 1985
1.3*	Articles of Amendment dated August 16, 2000
1.4*	Bylaw No 1 of Bonanza Red Lake Explorations Inc. (presently known as Eagleford Energy Inc.)
1.5*	Special By-Law No 1 – Respecting the borrowing of money and the issue of securities of Bonanza Red Lake Explorations Inc. (presently known as Eagleford Energy Inc.)
1.6***	Articles of Amalgamation dated November 30, 2009
4.1*	2000 Stock Option Plan
4.2*	Code of Business Conduct and Ethics
4.3*	Audit Committee Charter
4.4*	Petroleum and Natural Gas Committee Charter
4.5*	Compensation Committee Charter
4.6*	Purchase and Sale Agreement dated February 5, 2008 among Eugenic Corp., 1354166 Alberta Ltd., and the Vendors of 1354166 Alberta Ltd.
4.7**	Amended Audit Committee Charter
4.8****	Amended Stock Option Plan
4.9******	Asset Purchase Agreement between Eagleford Energy Inc., and Source Re-Work Program Inc., dated May 12, 2010
4.10******	Addendum dated June 10, 2010 to the Asset Purchase Agreement between Eagleford Energy Inc. and Source Re-Work Program Inc., dated May 12, 2010
4.11******	Addendum 2 dated June 30, 2010 to the Asset Purchase Agreement between Eagleford Energy Inc. and Source Re-Work Program Inc., dated May 12, 2010
4.12*****	Acquisition Agreement among Eagleford Energy Inc., Dyami Energy LLC and the Members of Dyami Energy LLC dated August 10, 2010
4.13******	Financial Advisory Services Agreement between Eagleford Energy Inc. and GarWood Securities, LLC dated June 10, 2010
4.14*******	Amended Stock Option Plan February 24, 2011
4.15********	Amendment dated December 31, 2010 to 6% Secured Promissory Note between Eagleford Energy Inc. and Benchmark Enterprises LLC
4.16********	Consent of Sproule Associates Limited
4.17	Evaluation of the P&NG Reserve of Eagleford Energy Inc.
8.1********	Subsidiaries of Eagleford Energy Inc.
12.1/12.2	Section 302 Certification of Chief Executive and Financial Officer
13.1/13.2	Section 906 Certification of Chief Executive and Financial Officer

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*****	Previously filed on April 29, 2009 by Registrant as part of Registration Statement on Form 20-F (SEC File No. 0-53646)
******	Previously Filed by Registrant as part of Amendment #2 to Registration Statement on Form 20F/A on July 14, 2009 (SEC File No. 0-53646)
*******	Previously Filed by Registrant on Form 6 K on December 1, 2009

****	Previously filed by Registrant on Form 20F/A on March 12, 2010
*****	Previously filed by Registrant on Form 6-K on September 16, 2010
******	Previously Filed by Registrant on Form 20F on February 11, 2011
*******	Previously filed by Registrant on Form 6-K on January 27, 2011
********	Previously filed by Registrant on Form 20F on February 16, 2012

EXHIBIT 4.17

EVALUATION OF THE P&NG RESERVES

OF

EAGLEFORD ENERGY INC.

(As of August 31, 2011)

Sproule

Worldwide Petroleum Consultants

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Copies:	Eagleford Energy Inc. (2 copies) Sproule Associates Limited (1 copy) Electronic (1 copy)
Project No.:	3391.18388
Prepared For:	Eagleford Energy Inc.
Authors:	Attila A. Szabo, P.Eng., Project Leader
Exclusivity:	This report has been prepared for the exclusive use of Eagleford Energy Inc. It may not be reproduced, distributed, or made available to any other company or person, regulatory body, or organization without the knowledge and written consent of Sproule, and without the complete contents of the report being made available to that party.

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Introduction

This report was prepared by Sproule Associates Limited ("Sproule") at the request of Mr. James Cassina, President of Eagleford Energy Inc. Eagleford Energy Inc. is hereinafter referred to as "the Company". The effective date of this report is August 31, 2011, and it consists of an evaluation of the P&NG reserves of the Company's interests in Alberta, Canada. This report was prepared in September and October 2011 for the purpose of evaluating the Company's P&NG reserves according to the Canadian Oil and Gas Evaluation Handbook (COGEH) reserve definitions that are consistent with the standards of National Instrument 51-101. This report was prepared for the Company's corporate purposes. At the request of the Company, estimates of the Capital Gas Cost Allowance (GCA) and Tax pools have not been included.

This report is included in one (1) volume and consists of an Introduction, Summary, Discussion, Constant Prices and Costs, National Instrument 51-101, and Appendices. The Introduction includes the summary of evaluation standards and procedures and pertinent author certificates; the Summary includes high-level summaries of the evaluation; and the Discussion includes general commentaries pertaining to the evaluation of the P&NG reserves. The Constant Prices and Costs section includes constant prices at August 31, 2011, for purposes of the Securities and Exchange Commission (SEC). The National Instrument 51-101 section presents Form 51-101F2 — Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor, and Tables 1 to 5 using Forecast Prices and Costs and Table 6 - Reconciliation of Company Gross Reserves (Before Royalty) by Principal Product Type. Reserves definitions, product price forecasts, abbreviations, units, conversion factors and general evaluation parameters are included in Appendices A, B, C, and D.

This report also contains detailed descriptions and evaluations for the individual properties (areas), on a property-by-property basis, including the following:

- Summary of the property evaluation;
- Summary of Pertinent Data;
- Table 1 – Well List/Reservoir Data;
- Table 2 - Summary of the estimates of proved and probable natural gas reserves and net present values;

- Table 3 - Forecasts of proved and probable natural gas production, revenue, and net present values, before income taxes;
- Table 4 – Entity Interests;
- Production history plots.

Field Operations

In the preparation of this evaluation, a field inspection of the properties was not performed. The relevant engineering data were made available by the Company or obtained from public sources and the non-confidential files at Sproule. No material information regarding the reserves evaluation would have been obtained by an on-site visit.

Historical Data, Interests and Burdens

1. All historical production, revenue and expense data, product prices actually received, and other data that were obtained from the Company or from public sources were accepted as represented, without any further investigation by Sproule.
2. Property descriptions, details of interests held, and well data, as supplied by the Company, were accepted as represented. No investigation was made into either the legal titles held or any operating agreements in place relating to the subject properties.
3. Lessor and overriding royalties and other burdens were obtained from the Company. No further investigation was undertaken by Sproule.
4. Sproule reserves the right to review all calculations made, referred to or included in this report and to revise the estimates as a result of erroneous data supplied by the Company or information that exists but was not made available to us, which becomes known subsequent to the preparation of this report.

Evaluation Standards

This report has been prepared by Sproule using current geological and engineering knowledge, techniques and computer software. It has been prepared within the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta

("APEGGA"). This report adheres in all material aspects to the "best practices" recommended in the COGE Handbook which are in accordance with principles and definitions established by the Calgary Chapter of the Society of Petroleum Evaluation Engineers. The COGE Handbook is incorporated by reference in National Instrument 51-101.

Evaluation Procedures

1. The Company provided Sproule with recent revenue statements to determine certain economic parameters.

2. The forecast of the natural gas price used in this evaluation was based on Sproule's August 31, 2011 price forecasts. Further discussion is included in Appendix B.

3. The constant price used in this report complies with the Securities & Exchange Commission's (SEC) regulations. It was calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period.

4. Well abandonment and disconnect costs were included in this report at the entity level for wells which have reserves assigned. No allowances for reclamation or salvage values were made. Further discussion is included in Appendix D.

5. For this evaluation, Sproule worked on the reserves evaluation model, Value Navigator (ValNav). The functionality of the program is not the responsibility of Sproule, and results were accepted as calculated by the model. Sproule's responsibility is limited to the quality of the data input and reasonableness of the outcoming results.

Evaluation Results

1. The analysis of individual properties as reported herein was conducted within the context and scope of an evaluation of a unique group of properties in aggregate. Use of this report outside of this scope may not be appropriate.

2. The accuracy of reserves estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time this report was prepared, the estimates presented herein are considered reasonable. However, they should be accepted with the understanding that reservoir and financial performance

subsequent to the date of the estimates may necessitate revision. These revisions may be material.

3. The net present values of the reserves presented in this report simply represent discounted future cash flow values at several discount rates. Though net present values form an integral part of fair market value estimations, without consideration for other economic criteria, they are not to be construed as Sproule's opinion of fair market value.

4. Due to rounding, certain totals may not be consistent from one presentation to the next.

BOE Cautionary Statement

BOE's (or 'McfGE's' or other applicable units of equivalency) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl (or 'An McfGE conversion ratio of 1 bbl: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.

Forward-Looking Statements

This report may contain forward-looking statements including expectations of future production revenues and capital expenditures. Information concerning reserves may also be deemed to be forward-looking as estimates involve the implied assessment that the reserves described can be profitably produced in future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated. These risks include, but are not limited to: the underlying risks of the oil and gas industry (i.e., corporate commitment, regulatory approval, operational risks in development, exploration and production); potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimations; the uncertainty of estimates and projections relating to production; costs and expenses; health, safety and environmental factors; commodity prices; and exchange rate fluctuation.

Exclusivity

This report has been prepared for the exclusive use of Eagleford Energy Inc. It may not be reproduced, distributed, or made available to any other company or person, regulatory body, or organization without the knowledge and written consent of Sproule, and without the complete contents of the report being made available to that party.

Certification

Report Preparation

The report entitled "Evaluation of the P&NG Reserves of Eagleford Energy Inc. (As of August 31, 2011)" was prepared by the following Sproule personnel:

Original Signed by Attila A. Szabo, P.Eng.

Attila A. Szabo, P.Eng.
Project Leader;
Senior Petroleum Engineer and Partner
07 / 10 /2011 dd/mm/yr

Sproule Executive Endorsement

This report has been reviewed and endorsed by the following Executive of Sproule:

Original Signed by Harry J. Helwerda, P.Eng., FEC

Harry J. Helwerda, P.Eng., FEC
Executive Vice-President and Director
07 / 10 /2011 dd/mm/yr

Permit to Practice

Sproule Associates Limited is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and our permit number is P00417.

Certificate

Attila A. Szabo, B.Sc., P.Eng.

I, Attila A. Szabo, Senior Petroleum Engineer and Partner, of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. B.Sc., Chemical Engineering (1980), University of Calgary, Calgary, Alberta, Canada

2. I am a registered professional:
   a. Professional Engineer (P.Eng.) Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
   b. Society of Petroleum Engineers (SPE)
   c. Society of Petroleum Evaluation Engineers (SPEE)

4. I am a qualified reserves evaluator and reserves auditor as defined in National Instrument 51-101.

5. My contribution to the report entitled "Evaluation of the P&NG Reserves of Eagleford Energy Inc. (As of August 31, 2011)" is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Eagleford Energy Inc.

Original Signed by Attila A. Szabo, P.Eng.

Attila A. Szabo, P.Eng.

Certificate

Harry J. Helwerda, B.Sc., P.Eng., FEC

I, Harry J. Helwerda, Executive Vice-President, and Director of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. B.Sc. Civil Engineering (1978) University of Calgary, Calgary AB, Canada

2. I am a registered professional:
   a. Professional Engineer (P.Eng.) Province of Alberta, Canada

3. I have been bestowed with the designation Fellow Engineers Canada (FEC)

4. I am a member of the following professional organizations:
   a. Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
   b. Society of Petroleum Engineers (SPE)
   c. Society of Petroleum Evaluation Engineers (SPEE)

5. I am a qualified reserves evaluator and reserves auditor as defined in National Instrument 51-101.

6. My contribution to the report entitled "Evaluation of the P&NG Reserves of Eagleford Energy Inc. (As of August 31, 2011)" is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

7. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Eagleford Energy Inc.

Original Signed by Harry J. Helwerda, P.Eng., FEC

Harry J. Helwerda, P.Eng., FEC

Summary

Table S-1 summarizes our evaluation, before income taxes, of the P&NG reserves of Eagleford Energy Inc., as of August 31, 2011.

Changes to royalties enacted by legislation in Alberta have been included in the report.

The reserves definitions and ownership classification used in this evaluation are the standards defined by COGEH reserve definitions and consistent with NI 51-101 and used by Sproule. The natural gas reserves are presented in millions of cubic feet, at base conditions of 14.65 psia and 60 degrees Fahrenheit.

The net present values of the reserves are presented (on a before tax basis) in Canadian dollars and are based on annual projections of net revenue, which were discounted at various rates using the mid-period discounting method. These rates are 5, 10, 15 and 20 percent and undiscounted.

The price forecasts that formed the basis for the revenue projections in the evaluation were based on Sproule's August 31, 2011 pricing model. Table S-2 presents a summary of selected forecasts.

Summary forecasts of production and net revenue for the various reserves categories are presented in Tables S-3 through S-3B, respectively. Well abandonment and disconnect costs have been included in this report at the entity level for all wells assigned reserves and are summarized in the Corporate totals for the various reserves categories.

Table S-1

Eagleford Energy Inc.

Consolidation

SUMMARY OF THE EVALUATION OF THE P.& N.G. RESERVES

(As of Date: 2011-08-31)

	Remaining Reserves			Net Present Values Before Income Taxes				
	Gross	Company						
	100%	Gross	Net	@ 0%	@ 5%	@ 10%	@ 15%	@ 20%
				M$	M$	M$	M$	M$
Non-Assoc, Assoc Gas (MMcf)								
Proved Developed Producing	3901	203	161	444	288	205	155	124
Probable Developed Producing	1276	66	49	182	77	39	23	15
Total Proved+Probable	5177	269	211	626	365	243	178	139
Grand Total (Mboe)								
Proved Developed Producing	650.1	33.8	26.9	444	288	205	155	124
Probable Developed Producing	212.7	11.1	8.2	182	77	39	23	15
Total Proved+Probable	862.9	44.8	35.1	626	365	243	178	139

Table S-2 Summary of Selected Price Forecasts (Effective August 31, 2011)				
Year	WTI Cushing[a] Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Alberta AECO-C Spot ($Cdn/MMBTU)	Henry Hub ($US/MMBtu)
Historical				
2006	66.09	73.30	7.16	7.23
2007	72.27	77.06	6.65	6.86
2008	99.59	102.85	8.15	9.04
2009	61.63	66.20	4.19	4.01
2010	79.43	77.80	4.16	4.39
Forecast				
2011	90.28	87.42	3.55	4.12
2012	93.23	90.32	3.94	4.52
2013	95.58	92.62	4.41	4.99
2014	95.97	92.99	5.21	5.80
2015	97.42	94.41	6.43	7.04
2016	99.37	96.32	6.57	7.18
2017	101.35	98.26	6.71	7.32
2018	103.38	100.25	6.86	7.47
2019	105.45	102.27	7.00	7.62
2020	107.56	104.33	7.15	7.77
2021	109.71	106.44	7.31	7.92
Escalation rate of 2% thereafter				

Note:

a. 40 degrees API, 0.4% sulphur

Table S-3

Proved+Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil Mbbl	Heavy Oil Mbbl	Solution Gas MMcf	Non-Assoc Assoc Gas MMcf	Ethane Mbbl	Propane Mbbl	Butane Mbbl	Pentanes Plus Mbbl	Total NGL Mbbl	Sulphur MLt	Equiv Oil Mboe
Gross	0.0	0.0	0	5177	0.0	0.0	0.0	0.0	0.0	0.0	862.9
Co Grs	0.0	0.0	0	269	0.0	0.0	0.0	0.0	0.0	0.0	44.8
Co Net	0.0	0.0	0	211	0.0	0.0	0.0	0.0	0.0	0.0	35.1

Net Present Value

Discount Rate %	Total Net Capital M$	Before Tax Net Rev M$	ARTC Cap GCA M$	Aband Cost M$	SK Tax Overhead M$	Before Tax Cash Flow M$
0.0	0	633	0	6	0	626
5.0	0	366	0	1	0	365
8.0	0	283	0	0	0	282
10.0	0	244	0	0	0	243
12.0	0	213	0	0	0	213
15.0	0	178	0	0	0	178
20.0	0	139	0	0	0	139
25.0	0	113	0	0	0	113

Reserve Life = 38.2 yrs Reserve Half Life = 9.2 yrs BOE Reserve Index = 14.3

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs bbl/d	Gas Comp Grs Mcf/d	BOE Comp Grs boe/d	Oil Rev M$	Gas Rev M$	Other Rev M$	Total Crown M$	Non-Crown M$	Lease Expen M$	Other Expen M$	Total Cap M$	Aband Etc M$	BTax Cash Flow M$
2011	0	52	9	0	24	0	4	0	14	0	0	0	5
2012	0	50	8	0	75	0	15	0	41	0	0	0	19
2013	0	47	8	0	78	0	17	0	40	0	0	0	22
2014	0	44	7	0	86	0	21	0	39	0	0	0	27
2015	0	41	7	0	99	0	27	0	38	0	0	0	34
2016	0	39	6	0	95	0	26	0	36	0	0	0	33
2017	0	36	6	0	91	0	24	0	35	0	0	0	32
2018	0	34	6	0	87	0	22	0	34	0	0	0	30
2019	0	32	5	0	83	0	21	0	34	0	0	0	29
2020	0	30	5	0	80	0	19	0	33	0	0	0	28
2021	0	28	5	0	76	0	17	0	32	0	0	0	28
2022	0	26	4	0	73	0	15	0	31	0	0	0	27
2023	0	25	4	0	70	0	14	0	30	0	0	0	26
2024	0	23	4	0	67	0	13	0	30	0	0	0	25
2025	0	22	4	0	64	0	11	0	29	0	0	0	23
2026	0	20	3	0	61	0	10	0	28	0	0	0	22
2027	0	19	3	0	58	0	9	0	28	0	0	0	21
2028	0	18	3	0	56	0	8	0	27	0	0	0	20
2029	0	17	3	0	53	0	7	0	27	0	0	0	19
2030	0	16	3	0	51	0	7	0	26	0	0	0	18
SubT				0	1428	0	306	0	633	0	0	0	489
19yr				0	574	0	42	0	387	0	0	6	138
Total				0	2001	0	349	0	1020	0	0	6	626
Discounted Cash Streams	5%			0	1121	0	226	0	530	0	0	1	365
	10%			0	747	0	162	0	342	0	0	0	243
	15%			0	554	0	124	0	251	0	0	0	178
	20%			0	439	0	100	0	200	0	0	0	139

Sproule

Table S-3A

Proved Developed Producing

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil Mbbl	Heavy Oil Mbbl	Solution Gas MMcf	Non-Assoc Assoc Gas MMcf	Ethane Mbbl	Propane Mbbl	Butane Mbbl	Pentanes Plus Mbbl	Total NGL Mbbl	Sulphur MLt	Equiv Oil Mboe
Gross	0.0	0.0	0	3901	0.0	0.0	0.0	0.0	0.0	0.0	650.1
Co Grs	0.0	0.0	0	203	0.0	0.0	0.0	0.0	0.0	0.0	33.8
Co Net	0.0	0.0	0	161	0.0	0.0	0.0	0.0	0.0	0.0	26.9

Net Present Value

Discount Rate %	Total Net Capital M$	Before Tax Net Rev M$	ARTC Cap GCA M$	Aband Cost M$	SK Tax Overhead M$	Before Tax Cash Flow M$
0.0	0	449	0	5	0	444
5.0	0	290	0	1	0	288
8.0	0	233	0	1	0	233
10.0	0	205	0	0	0	205
12.0	0	182	0	0	0	182
15.0	0	155	0	0	0	155
20.0	0	124	0	0	0	124
25.0	0	102	0	0	0	102

Reserve Life = 30.2 yrs Reserve Half Life = 7.1 yrs BOE Reserve Index = 11.2

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs bbl/d	Gas Comp Grs Mcf/d	BOE Comp Grs boe/d	Oil Rev M$	Gas Rev M$	Other Rev M$	Total Crown M$	Non-Crown M$	Lease Expen M$	Other Expen M$	Total Cap M$	Aband Etc M$	BTax Cash Flow M$
2011	0	51	8	0	23	0	4	0	14	0	0	0	5
2012	0	48	8	0	72	0	14	0	40	0	0	0	18
2013	0	44	7	0	73	0	15	0	38	0	0	0	20
2014	0	41	7	0	79	0	18	0	36	0	0	0	25
2015	0	37	6	0	90	0	23	0	35	0	0	0	32
2016	0	34	6	0	84	0	21	0	33	0	0	0	30
2017	0	32	5	0	79	0	19	0	32	0	0	0	28
2018	0	29	5	0	74	0	17	0	31	0	0	0	27
2019	0	27	4	0	70	0	15	0	30	0	0	0	26
2020	0	25	4	0	66	0	13	0	29	0	0	0	25
2021	0	23	4	0	62	0	11	0	28	0	0	0	23
2022	0	21	3	0	58	0	9	0	27	0	0	0	22
2023	0	19	3	0	54	0	8	0	26	0	0	0	20
2024	0	18	3	0	51	0	7	0	25	0	0	0	19
2025	0	16	3	0	48	0	6	0	24	0	0	0	18
2026	0	15	3	0	45	0	5	0	24	0	0	0	16
2027	0	14	2	0	42	0	4	0	23	0	0	0	15
2028	0	13	2	0	40	0	3	0	23	0	0	0	14
2029	0	12	2	0	37	0	3	0	22	0	0	0	12
2030	0	11	2	0	35	0	2	0	22	0	0	0	11
SubT				0	1184	0	217	0	561	0	0	0	406
11yr				0	216	0	11	0	162	0	0	5	38
Total				0	1400	0	228	0	722	0	0	5	444
Discounted Cash Streams	5%			0	885	0	162	0	433	0	0	1	288
	10%			0	627	0	124	0	299	0	0	0	205
	15%			0	481	0	99	0	227	0	0	0	155
	20%			0	389	0	81	0	184	0	0	0	124

Table S-3B

Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil Mbbl	Heavy Oil Mbbl	Solution Gas MMcf	Non-Assoc Assoc Gas MMcf	Ethane Mbbl	Propane Mbbl	Butane Mbbl	Pentanes Plus Mbbl	Total NGL Mbbl	Sulphur MLt	Equiv Oil Mboe
Gross	0.0	0.0	0	1276	0.0	0.0	0.0	0.0	0.0	0.0	212.7
Co Grs	0.0	0.0	0	66	0.0	0.0	0.0	0.0	0.0	0.0	11.1
Co Net	0.0	0.0	0	49	0.0	0.0	0.0	0.0	0.0	0.0	8.2

Net Present Value

Discount Rate %	Total Net Capital M$	Before Tax Net Rev M$	ARTC Cap GCA M$	Aband Cost M$	SK Tax Overhead M$	Before Tax Cash Flow M$
0.0	0	183	0	1	0	182
5.0	0	76	0	0	0	77
8.0	0	50	0	0	0	50
10.0	0	39	0	0	0	39
12.0	0	31	0	0	0	31
15.0	0	23	0	0	0	23
20.0	0	15	0	0	0	15
25.0	0	11	0	0	0	11

Reserve Life = 38.2 yrs Reserve Half Life = 19.4 yrs BOE Reserve Index = 90.4

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs bbl/d	Gas Comp Grs Mcf/d	BOE Comp Grs boe/d	Oil Rev M$	Gas Rev M$	Other Rev M$	Total Crown M$	Non-Crown M$	Lease Expen M$	Other Expen M$	Total Cap M$	Aband Etc M$	BTax Cash Flow M$
2011	0	2	0	0	1	0	0	0	0	0	0	0	0
2012	0	2	0	0	3	0	1	0	1	0	0	0	1
2013	0	3	0	0	5	0	1	0	2	0	0	0	1
2014	0	4	1	0	7	0	2	0	2	0	0	0	2
2015	0	4	1	0	10	0	4	0	3	0	0	0	3
2016	0	4	1	0	11	0	5	0	3	0	0	0	3
2017	0	5	1	0	12	0	5	0	3	0	0	0	3
2018	0	5	1	0	13	0	5	0	4	0	0	0	4
2019	0	5	1	0	13	0	6	0	4	0	0	0	4
2020	0	5	1	0	14	0	6	0	4	0	0	0	4
2021	0	5	1	0	15	0	6	0	4	0	0	0	4
2022	0	5	1	0	15	0	6	0	4	0	0	0	5
2023	0	5	1	0	15	0	6	0	4	0	0	0	5
2024	0	5	1	0	16	0	6	0	5	0	0	0	5
2025	0	5	1	0	16	0	6	0	5	0	0	0	6
2026	0	5	1	0	16	0	5	0	5	0	0	0	6
2027	0	5	1	0	16	0	5	0	5	0	0	0	6
2028	0	5	1	0	16	0	5	0	5	0	0	0	7
2029	0	5	1	0	16	0	5	0	5	0	0	0	7
2030	0	5	1	0	16	0	4	0	5	0	0	0	7
SubT				0	244	0	89	0	72	0	0	0	83
19yr				0	357	0	31	0	226	0	0	1	99
Total				0	601	0	120	0	298	0	0	1	182
Discounted Cash Streams	5%			0	236	0	63	0	97	0	0	0	77
	10%			0	120	0	38	0	43	0	0	0	39
	15%			0	73	0	26	0	24	0	0	0	23
	20%			0	50	0	18	0	16	0	0	0	15

Sproule

Discussion

The Company's P&NG reserves are located in the province of Alberta, Canada.

Reserves and Production

The natural gas reserves were estimated from production decline curve analyses.

Forecasts of net revenue were prepared by predicting annual production from the reserves, and product prices. Annual production was forecast taking into account historical production trends of the Company's producing wells, applicable regulatory conditions, existing or anticipated contract rates, and by comparison with other wells in the vicinity producing from similar reservoirs.

Net Present Values

The estimates of the P&NG reserves and their respective net present values, summarized by property and by reserves category, before income taxes, are presented in Table D-1. Detailed forecasts of production and net revenue for the various reserves categories for the Company are presented in Tables D-2 through D-2B. Well abandonment and disconnect costs are included at the entity level for all entities that have reserves assigned.

Table D-1

Eagleford Energy Inc.

Default Scenario

SUMMARY OF THE EVALUATION OF THE P.&N.G. RESERVES

(As of Date: 2011-08-31)

	Lt, Med, Heavy Oil			Non-Assoc., Assoc. Gas / Solution Gas			Natural Gas Liquids / Sulphur			Net Present Values Before Income Taxes			
	Remaining Reserves	Company Reserves		Remaining Reserves	Company Reserves		Remaining Reserves	Company Reserves					
		Gross	Net		Gross	Net		Gross	Net	@ 0%	@ 5%	@ 10%	@ 15%
	Mbbl	Mbbl	Mbbl	MMcf MMcf	MMcf MMcf	MMcf MMcf	Mbbl MLt	Mbbl MLt	Mbbl MLt	M$	M$	M$	M$
Eagleford Energy Inc.													
PDP				3901	203	161				444	288	205	155
TP				3901	203	161				444	288	205	155
PBDP				1276	66	49				182	77	39	23
TPP				5177	269	211				626	365	243	178
Botha													
PDP				3901	203	161				444	288	205	155
TP				3901	203	161				444	288	205	155
PBDP				1276	66	49				182	77	39	23
TPP				5177	269	211				626	365	243	178

Sproule

Table D-2

Proved+Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil	Heavy Oil	Solution Gas	Non-Assoc Assoc Gas	Ethane	Propane	Butane	Pentanes Plus	Total NGL	Sulphur	Equiv Oil
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MLt	Mboe
Gross	0.0	0.0	0	5177	0.0	0.0	0.0	0.0	0.0	0.0	862.9
Co Grs	0.0	0.0	0	269	0.0	0.0	0.0	0.0	0.0	0.0	44.8
Co Net	0.0	0.0	0	211	0.0	0.0	0.0	0.0	0.0	0.0	35.1

Net Present Value

Discount Rate	Total Net Capital	Before Tax Net Rev	ARTC Cap GCA	Aband Cost	SK Tax Overhead	Before Tax Cash Flow
%	M$	M$	M$	M$	M$	M$
0.0	0	633	0	6	0	626
5.0	0	366	0	1	0	365
8.0	0	283	0	0	0	282
10.0	0	244	0	0	0	243
12.0	0	213	0	0	0	213
15.0	0	178	0	0	0	178
20.0	0	139	0	0	0	139
25.0	0	113	0	0	0	113

Reserve Life = 38.2 yrs Reserve Half Life = 9.2 yrs BOE Reserve Index = 14.3

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs	Gas Comp Grs	BOE Comp Grs	Oil Rev	Gas Rev	Other Rev	Total Crown	Non-Crown	Lease Expen	Other Expen	Total Cap	Aband Etc	BTax Cash Flow
	bbl/d	Mcf/d	boe/d	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	52	9	0	24	0	4	0	14	0	0	0	5
2012	0	50	8	0	75	0	15	0	41	0	0	0	19
2013	0	47	8	0	78	0	17	0	40	0	0	0	22
2014	0	44	7	0	86	0	21	0	39	0	0	0	27
2015	0	41	7	0	99	0	27	0	38	0	0	0	34
2016	0	39	6	0	95	0	26	0	36	0	0	0	33
2017	0	36	6	0	91	0	24	0	35	0	0	0	32
2018	0	34	6	0	87	0	22	0	34	0	0	0	30
2019	0	32	5	0	83	0	21	0	34	0	0	0	29
2020	0	30	5	0	80	0	19	0	33	0	0	0	28
2021	0	28	5	0	76	0	17	0	32	0	0	0	28
2022	0	26	4	0	73	0	15	0	31	0	0	0	27
2023	0	25	4	0	70	0	14	0	30	0	0	0	26
2024	0	23	4	0	67	0	13	0	30	0	0	0	25
2025	0	22	4	0	64	0	11	0	29	0	0	0	23
2026	0	20	3	0	61	0	10	0	28	0	0	0	22
2027	0	19	3	0	58	0	9	0	28	0	0	0	21
2028	0	18	3	0	56	0	8	0	27	0	0	0	20
2029	0	17	3	0	53	0	7	0	27	0	0	0	19
2030	0	16	3	0	51	0	7	0	26	0	0	0	18
SubT				0	1428	0	306	0	633	0	0	0	489
19yr				0	574	0	42	0	387	0	0	6	138
Total				0	2001	0	349	0	1020	0	0	6	626
Discounted	5%			0	1121	0	226	0	530	0	0	1	365
Cash	10%			0	747	0	162	0	342	0	0	0	243
Streams	15%			0	554	0	124	0	251	0	0	0	178
	20%			0	439	0	100	0	200	0	0	0	139

Table D-2

Proved+Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	2	1007	123	6	5	3.70
2012	2	965	353	18	14	4.09
2013	2	904	330	17	13	4.56
2014	2	848	309	16	11	5.36
2015	2	795	290	15	10	6.58
2016	2	745	273	14	10	6.72
2017	2	698	255	13	9	6.86
2018	2	655	239	12	9	7.01
2019	2	614	224	12	8	7.15
2020	2	575	211	11	8	7.30
2021	2	539	197	10	8	7.46
2022	2	506	185	10	7	7.61
2023	2	474	173	9	7	7.76
2024	2	445	163	8	7	7.91
2025	2	417	152	8	6	8.06
2026	2	391	143	7	6	8.22
2027	2	366	134	7	6	8.38
2028	2	343	126	7	5	8.55
2029	2	322	118	6	5	8.71
2030	2	302	110	6	5	8.89
SubT			4106	213	160	
19yr			1071	56	51	
Total			5177	269	211	

Table D-2

Proved+Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

	Revenue						Royalties						
Year	Oil M$	Gas M$	NGL M$	Sul M$	Roy M$	Other Income M$	Crown M$	Adjust M$	FH/ Indian M$	ORR M$	Min Taxes M$	Opex M$	NPI/ Other Expense M$
2011	0	24	0	0	0	0	5	0	0	0	0	14	0
2012	0	75	0	0	0	0	16	1	0	0	0	41	0
2013	0	78	0	0	0	0	18	1	0	0	0	40	0
2014	0	86	0	0	0	0	22	1	0	0	0	39	0
2015	0	99	0	0	0	0	29	1	0	0	0	38	0
2016	0	95	0	0	0	0	27	1	0	0	0	36	0
2017	0	91	0	0	0	0	25	1	0	0	0	35	0
2018	0	87	0	0	0	0	23	1	0	0	0	34	0
2019	0	83	0	0	0	0	21	1	0	0	0	34	0
2020	0	80	0	0	0	0	20	1	0	0	0	33	0
2021	0	76	0	0	0	0	18	1	0	0	0	32	0
2022	0	73	0	0	0	0	16	1	0	0	0	31	0
2023	0	70	0	0	0	0	15	1	0	0	0	30	0
2024	0	67	0	0	0	0	13	1	0	0	0	30	0
2025	0	64	0	0	0	0	12	1	0	0	0	29	0
2026	0	61	0	0	0	0	11	0	0	0	0	28	0
2027	0	58	0	0	0	0	10	0	0	0	0	28	0
2028	0	56	0	0	0	0	9	0	0	0	0	27	0
2029	0	53	0	0	0	0	8	0	0	0	0	27	0
2030	0	51	0	0	0	0	7	0	0	0	0	26	0
SubT	0	1428	0	0	0	0	322	16	0	0	0	633	0
19yr	0	574	0	0	0	0	44	2	0	0	0	387	0
Total	0	2001	0	0	0	0	366	17	0	0	0	1020	0

		Capital											
Year	Oper Inc M$	CEE M$	CDE M$	CCA M$	COGPE M$	Total Capital M$	Net Rev M$	Cum Net Rev M$	ARTC M$	Aband Cost M$	SK Tax M$	Cash Flow M$	Cum Cash Flow M$
2011	5	0	0	0	0	0	5	5	0	0	0	5	5
2012	19	0	0	0	0	0	19	25	0	0	0	19	25
2013	22	0	0	0	0	0	22	46	0	0	0	22	46
2014	27	0	0	0	0	0	27	73	0	0	0	27	73
2015	34	0	0	0	0	0	34	108	0	0	0	34	108
2016	33	0	0	0	0	0	33	141	0	0	0	33	141
2017	32	0	0	0	0	0	32	172	0	0	0	32	172
2018	30	0	0	0	0	0	30	203	0	0	0	30	203
2019	29	0	0	0	0	0	29	232	0	0	0	29	232
2020	28	0	0	0	0	0	28	260	0	0	0	28	260
2021	28	0	0	0	0	0	28	288	0	0	0	28	288
2022	27	0	0	0	0	0	27	315	0	0	0	27	315
2023	26	0	0	0	0	0	26	340	0	0	0	26	340
2024	25	0	0	0	0	0	25	365	0	0	0	25	365
2025	23	0	0	0	0	0	23	388	0	0	0	23	388
2026	22	0	0	0	0	0	22	410	0	0	0	22	410
2027	21	0	0	0	0	0	21	431	0	0	0	21	431
2028	20	0	0	0	0	0	20	452	0	0	0	20	452
2029	19	0	0	0	0	0	19	471	0	0	0	19	471
2030	18	0	0	0	0	0	18	489	0	0	0	18	489
SubT	489	0	0	0	0	0	489		0	0	0	489	
19yr	144	0	0	0	0	0	144		0	6	0	138	
Total	633	0	0	0	0	0	633		0	6	0	626	

	Discounted Cash Streams NPV (M$)						
discR%	5	10	12	15	18	20	25
BT Net	366	244	213	178	153	139	113
BT Cash Flow	365	243	213	178	152	139	113

Table D-2A

Proved Developed Producing

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil Mbbl	Heavy Oil Mbbl	Solution Gas MMcf	Non-Assoc Assoc Gas MMcf	Ethane Mbbl	Propane Mbbl	Butane Mbbl	Pentanes Plus Mbbl	Total NGL Mbbl	Sulphur MLt	Equiv Oil Mboe
Gross	0.0	0.0	0	3901	0.0	0.0	0.0	0.0	0.0	0.0	650.1
Co Grs	0.0	0.0	0	203	0.0	0.0	0.0	0.0	0.0	0.0	33.8
Co Net	0.0	0.0	0	161	0.0	0.0	0.0	0.0	0.0	0.0	26.9

Net Present Value

Discount Rate %	Total Net Capital M$	Before Tax Net Rev M$	ARTC Cap GCA M$	Aband Cost M$	SK Tax Overhead M$	Before Tax Cash Flow M$
0.0	0	449	0	5	0	444
5.0	0	290	0	1	0	288
8.0	0	233	0	1	0	233
10.0	0	205	0	0	0	205
12.0	0	182	0	0	0	182
15.0	0	155	0	0	0	155
20.0	0	124	0	0	0	124
25.0	0	102	0	0	0	102

Reserve Life = 30.2 yrs Reserve Half Life = 7.1 yrs BOE Reserve Index = 11.2

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs bbl/d	Gas Comp Grs Mcf/d	BOE Comp Grs boe/d	Oil Rev M$	Gas Rev M$	Other Rev M$	Total Crown M$	Non-Crown M$	Lease Expen M$	Other Expen M$	Total Cap M$	Aband Etc M$	BTax Cash Flow M$
2011	0	51	8	0	23	0	4	0	14	0	0	0	5
2012	0	48	8	0	72	0	14	0	40	0	0	0	18
2013	0	44	7	0	73	0	15	0	38	0	0	0	20
2014	0	41	7	0	79	0	18	0	36	0	0	0	25
2015	0	37	6	0	90	0	23	0	35	0	0	0	32
2016	0	34	6	0	84	0	21	0	33	0	0	0	30
2017	0	32	5	0	79	0	19	0	32	0	0	0	28
2018	0	29	5	0	74	0	17	0	31	0	0	0	27
2019	0	27	4	0	70	0	15	0	30	0	0	0	26
2020	0	25	4	0	66	0	13	0	29	0	0	0	25
2021	0	23	4	0	62	0	11	0	28	0	0	0	23
2022	0	21	3	0	58	0	9	0	27	0	0	0	22
2023	0	19	3	0	54	0	8	0	26	0	0	0	20
2024	0	18	3	0	51	0	7	0	25	0	0	0	19
2025	0	16	3	0	48	0	6	0	24	0	0	0	18
2026	0	15	3	0	45	0	5	0	24	0	0	0	16
2027	0	14	2	0	42	0	4	0	23	0	0	0	15
2028	0	13	2	0	40	0	3	0	23	0	0	0	14
2029	0	12	2	0	37	0	3	0	22	0	0	0	12
2030	0	11	2	0	35	0	2	0	22	0	0	0	11
SubT				0	1184	0	217	0	561	0	0	0	406
11yr				0	216	0	11	0	162	0	0	5	38
Total				0	1400	0	228	0	722	0	0	5	444
Discounted Cash Streams	5%			0	885	0	162	0	433	0	0	1	288
	10%			0	627	0	124	0	299	0	0	0	205
	15%			0	481	0	99	0	227	0	0	0	155
	20%			0	389	0	81	0	184	0	0	0	124

Table D-2A

Proved Developed Producing

Eagleford Energy Inc.

Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily	Gas Gross	Gas Co Grs	Gas Co Net	Gas Price
		Mcf/d	MMcf	MMcf	MMcf	$/Mcf
2011	2	974	119	6	5	3.70
2012	2	922	337	18	13	4.09
2013	2	848	310	16	12	4.56
2014	2	780	285	15	11	5.36
2015	2	718	262	14	10	6.58
2016	2	661	242	13	9	6.72
2017	2	608	222	12	8	6.86
2018	2	560	204	11	8	7.01
2019	2	515	188	10	7	7.15
2020	2	474	174	9	7	7.30
2021	2	437	159	8	7	7.46
2022	2	402	147	8	6	7.61
2023	2	370	135	7	6	7.76
2024	2	341	125	6	5	7.91
2025	2	314	114	6	5	8.06
2026	2	289	105	5	5	8.22
2027	2	266	97	5	5	8.38
2028	2	245	90	5	4	8.55
2029	2	225	82	4	4	8.71
2030	2	208	76	4	4	8.89
SubT			3473	181	140	
11yr			428	22	21	
Total			3901	203	161	

Table D-2A

Proved Developed Producing

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil M$	Gas M$	NGL M$	Sul M$	Roy M$	Other Income M$	Crown M$	Adjust M$	FH/ Indian M$	ORR M$	Min Taxes M$	Opex M$	NPI/ Other Expense M$
	Revenue						Royalties						
2011	0	23	0	0	0	0	4	0	0	0	0	14	0
2012	0	72	0	0	0	0	15	1	0	0	0	40	0
2013	0	73	0	0	0	0	16	1	0	0	0	38	0
2014	0	79	0	0	0	0	19	1	0	0	0	36	0
2015	0	90	0	0	0	0	24	1	0	0	0	35	0
2016	0	84	0	0	0	0	22	1	0	0	0	33	0
2017	0	79	0	0	0	0	20	1	0	0	0	32	0
2018	0	74	0	0	0	0	17	1	0	0	0	31	0
2019	0	70	0	0	0	0	15	1	0	0	0	30	0
2020	0	66	0	0	0	0	13	1	0	0	0	29	0
2021	0	62	0	0	0	0	12	1	0	0	0	28	0
2022	0	58	0	0	0	0	10	0	0	0	0	27	0
2023	0	54	0	0	0	0	8	0	0	0	0	26	0
2024	0	51	0	0	0	0	7	0	0	0	0	25	0
2025	0	48	0	0	0	0	6	0	0	0	0	24	0
2026	0	45	0	0	0	0	5	0	0	0	0	24	0
2027	0	42	0	0	0	0	4	0	0	0	0	23	0
2028	0	40	0	0	0	0	4	0	0	0	0	23	0
2029	0	37	0	0	0	0	3	0	0	0	0	22	0
2030	0	35	0	0	0	0	3	0	0	0	0	22	0
SubT	0	1184	0	0	0	0	229	11	0	0	0	561	0
11yr	0	216	0	0	0	0	12	1	0	0	0	162	0
Total	0	1400	0	0	0	0	240	12	0	0	0	722	0

Year	Oper Inc M$	CEE M$	CDE M$	CCA M$	COGPE M$	Total Capital M$	Net Rev M$	Cum Net Rev M$	ARTC M$	Aband Cost M$	SK Tax M$	Cash Flow M$	Cum Cash Flow M$
		Capital											
2011	5	0	0	0	0	0	5	5	0	0	0	5	5
2012	18	0	0	0	0	0	18	24	0	0	0	18	24
2013	20	0	0	0	0	0	20	44	0	0	0	20	44
2014	25	0	0	0	0	0	25	69	0	0	0	25	69
2015	32	0	0	0	0	0	32	100	0	0	0	32	100
2016	30	0	0	0	0	0	30	130	0	0	0	30	130
2017	28	0	0	0	0	0	28	159	0	0	0	28	159
2018	27	0	0	0	0	0	27	186	0	0	0	27	186
2019	26	0	0	0	0	0	26	211	0	0	0	26	211
2020	25	0	0	0	0	0	25	236	0	0	0	25	236
2021	23	0	0	0	0	0	23	259	0	0	0	23	259
2022	22	0	0	0	0	0	22	281	0	0	0	22	281
2023	20	0	0	0	0	0	20	301	0	0	0	20	301
2024	19	0	0	0	0	0	19	320	0	0	0	19	320
2025	18	0	0	0	0	0	18	338	0	0	0	18	338
2026	16	0	0	0	0	0	16	354	0	0	0	16	354
2027	15	0	0	0	0	0	15	369	0	0	0	15	369
2028	14	0	0	0	0	0	14	383	0	0	0	14	383
2029	12	0	0	0	0	0	12	395	0	0	0	12	395
2030	11	0	0	0	0	0	11	406	0	0	0	11	406
SubT	406	0	0	0	0	0	406		0	0	0	406	
11yr	44	0	0	0	0	0	44		0	5	0	38	
Total	449	0	0	0	0	0	449		0	5	0	444	

Discounted Cash Streams NPV (M$)

discR%	5	10	12	15	18	20	25
BT Net	290	205	182	155	135	124	102
BT Cash Flow	288	205	182	155	135	124	102

Sproule

Table D-2B

Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil Mbbl	Heavy Oil Mbbl	Solution Gas MMcf	Non-Assoc Assoc Gas MMcf	Ethane Mbbl	Propane Mbbl	Butane Mbbl	Pentanes Plus Mbbl	Total NGL Mbbl	Sulphur MLt	Equiv Oil Mboe
Gross	0.0	0.0	0	1276	0.0	0.0	0.0	0.0	0.0	0.0	212.7
Co Grs	0.0	0.0	0	66	0.0	0.0	0.0	0.0	0.0	0.0	11.1
Co Net	0.0	0.0	0	49	0.0	0.0	0.0	0.0	0.0	0.0	8.2

Net Present Value

Discount Rate %	Total Net Capital M$	Before Tax Net Rev M$	ARTC Cap GCA M$	Aband Cost M$	SK Tax Overhead M$	Before Tax Cash Flow M$
0.0	0	183	0	1	0	182
5.0	0	76	0	0	0	77
8.0	0	50	0	0	0	50
10.0	0	39	0	0	0	39
12.0	0	31	0	0	0	31
15.0	0	23	0	0	0	23
20.0	0	15	0	0	0	15
25.0	0	11	0	0	0	11

Reserve Life = 38.2 yrs Reserve Half Life = 19.4 yrs BOE Reserve Index = 90.4

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs bbl/d	Gas Comp Grs Mcf/d	BOE Comp Grs boe/d	Oil Rev M$	Gas Rev M$	Other Rev M$	Total Crown M$	Non-Crown M$	Lease Expen M$	Other Expen M$	Total Cap M$	Aband Etc M$	BTax Cash Flow M$
2011	0	2	0	0	1	0	0	0	0	0	0	0	0
2012	0	2	0	0	3	0	1	0	1	0	0	0	1
2013	0	3	0	0	5	0	1	0	2	0	0	0	1
2014	0	4	1	0	7	0	2	0	2	0	0	0	2
2015	0	4	1	0	10	0	4	0	3	0	0	0	3
2016	0	4	1	0	11	0	5	0	3	0	0	0	3
2017	0	5	1	0	12	0	5	0	3	0	0	0	3
2018	0	5	1	0	13	0	5	0	4	0	0	0	4
2019	0	5	1	0	13	0	6	0	4	0	0	0	4
2020	0	5	1	0	14	0	6	0	4	0	0	0	4
2021	0	5	1	0	15	0	6	0	4	0	0	0	4
2022	0	5	1	0	15	0	6	0	4	0	0	0	5
2023	0	5	1	0	15	0	6	0	4	0	0	0	5
2024	0	5	1	0	16	0	6	0	5	0	0	0	5
2025	0	5	1	0	16	0	6	0	5	0	0	0	6
2026	0	5	1	0	16	0	5	0	5	0	0	0	6
2027	0	5	1	0	16	0	5	0	5	0	0	0	6
2028	0	5	1	0	16	0	5	0	5	0	0	0	7
2029	0	5	1	0	16	0	5	0	5	0	0	0	7
2030	0	5	1	0	16	0	4	0	5	0	0	0	7
SubT				0	244	0	89	0	72	0	0	0	83
19yr				0	357	0	31	0	226	0	0	1	99
Total				0	601	0	120	0	298	0	0	1	182

		Oil Rev M$	Gas Rev M$	Other Rev M$	Total Crown M$	Non-Crown M$	Lease Expen M$	Other Expen M$	Total Cap M$	Aband Etc M$	BTax Cash Flow M$
Discounted	5%	0	236	0	63	0	97	0	0	0	77
Cash	10%	0	120	0	38	0	43	0	0	0	39
Streams	15%	0	73	0	26	0	24	0	0	0	23
	20%	0	50	0	18	0	16	0	0	0	15

Sproule

Table D-2B

Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	0	34	4	0	0	3.70
2012	0	43	16	1	1	4.09
2013	0	57	21	1	1	4.56
2014	0	68	25	1	1	5.36
2015	0	77	28	1	1	6.58
2016	0	84	31	2	1	6.72
2017	0	90	33	2	1	6.86
2018	0	95	35	2	1	7.01
2019	0	98	36	2	1	7.15
2020	0	101	37	2	1	7.30
2021	0	103	38	2	1	7.46
2022	0	104	38	2	1	7.61
2023	0	104	38	2	1	7.76
2024	0	104	38	2	1	7.91
2025	0	103	38	2	1	8.06
2026	0	102	37	2	1	8.22
2027	0	101	37	2	1	8.38
2028	0	99	36	2	1	8.55
2029	0	97	35	2	1	8.71
2030	0	94	34	2	1	8.89
SubT			633	33	19	
19yr			643	33	30	
Total			1276	66	49	

Table D-2B

Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

	Revenue						Royalties						
Year	Oil	Gas	NGL	Sul	Roy	Other Income	Crown	Adjust	FH/ Indian	ORR	Min Taxes	Opex	NPI/ Other Expense
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	1	0	0	0	0	0	0	0	0	0	0	0
2012	0	3	0	0	0	0	1	0	0	0	0	1	0
2013	0	5	0	0	0	0	2	0	0	0	0	2	0
2014	0	7	0	0	0	0	2	0	0	0	0	2	0
2015	0	10	0	0	0	0	4	0	0	0	0	3	0
2016	0	11	0	0	0	0	5	0	0	0	0	3	0
2017	0	12	0	0	0	0	5	0	0	0	0	3	0
2018	0	13	0	0	0	0	6	0	0	0	0	4	0
2019	0	13	0	0	0	0	6	0	0	0	0	4	0
2020	0	14	0	0	0	0	6	0	0	0	0	4	0
2021	0	15	0	0	0	0	6	0	0	0	0	4	0
2022	0	15	0	0	0	0	6	0	0	0	0	4	0
2023	0	15	0	0	0	0	6	0	0	0	0	4	0
2024	0	16	0	0	0	0	6	0	0	0	0	5	0
2025	0	16	0	0	0	0	6	0	0	0	0	5	0
2026	0	16	0	0	0	0	6	0	0	0	0	5	0
2027	0	16	0	0	0	0	5	0	0	0	0	5	0
2028	0	16	0	0	0	0	5	0	0	0	0	5	0
2029	0	16	0	0	0	0	5	0	0	0	0	5	0
2030	0	16	0	0	0	0	4	0	0	0	0	5	0
SubT	0	244	0	0	0	0	93	4	0	0	0	72	0
19yr	0	357	0	0	0	0	32	1	0	0	0	226	0
Total	0	601	0	0	0	0	126	6	0	0	0	298	0

		Capital											
Year	Oper Inc	CEE	CDE	CCA	COGPE	Total Capital	Net Rev	Cum Net Rev	ARTC	Aband Cost	SK Tax	Cash Flow	Cum Cash Flow
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	1	0	0	0	0	0	1	1	0	0	0	1	1
2013	1	0	0	0	0	0	1	3	0	0	0	1	3
2014	2	0	0	0	0	0	2	5	0	0	0	2	5
2015	3	0	0	0	0	0	3	8	0	0	0	3	8
2016	3	0	0	0	0	0	3	10	0	0	0	3	10
2017	3	0	0	0	0	0	3	14	0	0	0	3	14
2018	4	0	0	0	0	0	4	17	0	0	0	4	17
2019	4	0	0	0	0	0	4	21	0	0	0	4	21
2020	4	0	0	0	0	0	4	25	0	0	0	4	25
2021	4	0	0	0	0	0	4	29	0	0	0	4	29
2022	5	0	0	0	0	0	5	34	0	0	0	5	34
2023	5	0	0	0	0	0	5	39	0	0	0	5	39
2024	5	0	0	0	0	0	5	44	0	0	0	5	44
2025	6	0	0	0	0	0	6	50	0	0	0	6	50
2026	6	0	0	0	0	0	6	56	0	0	0	6	56
2027	6	0	0	0	0	0	6	62	0	0	0	6	62
2028	7	0	0	0	0	0	7	69	0	0	0	7	69
2029	7	0	0	0	0	0	7	76	0	0	0	7	76
2030	7	0	0	0	0	0	7	83	0	0	0	7	83
SubT	83	0	0	0	0	0	83		0	0	0	83	
19yr	100	0	0	0	0	0	100		0	1	0	99	
Total	183	0	0	0	0	0	183		0	1	0	182	

	Discounted Cash Streams NPV (M$)						
discR%	5	10	12	15	18	20	25
BT Net	76	39	31	23	18	15	11
BT Cash Flow	77	39	31	23	18	15	11

Sproule

Constant Prices and Costs

The constant price used in this report complies with the Securities & Exchange Commission's (SEC) regulations. It was calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period.

Table C-1, on the following page, summarizes our evaluation, based on constant prices and costs, before income taxes, of the P&NG reserves of Eagleford Energy Inc., as of August 31, 2011. The table presents summaries of the P&NG reserves for the various reserves categories valuation.

Table C-2 is also included and summarizes the reserves and values by property for the constant price case, before income taxes. Tables C-3 through C-3B show the cash flow forecasts for the constant price case for the various reserves categories.

The natural gas constant price used in this specific evaluation was based on the August 31, 2011 actual posted price as determined by Sproule. The constant price used in this report is as follows:

Natural Gas:	
AECO-C Spot	3.77 $/MMbtu

Appropriate adjustments have been made to the natural gas price to account for quality and transportation, and to reflect actual historical prices received for each property. This blending of constant prices may result in the appearance of varying constant prices in the Corporate cash flows.

The remaining assumptions relating to the calculation and evaluation of the reserves are the same as those presented in the detailed evaluation.

It is important to note that the estimate of the reserves to be recovered from a gas field is the sum of all the cumulative production until an economic limit is reached. The economic limit is a function of the production forecast, future prices and operating costs (including royalties and taxes) to maintain production. Consequently, when estimates of future prices and costs are changed, economic limits are also altered. In the evaluation process, production forecasts are truncated at the economic limits and thus, reserves estimates vary with price and cost sensitivities, as is the case between forecast and constant prices and cost forecasts.

Also, some entities may have reserves assigned to them under one price and cost scenario, but under less favourable price and cost projections, the net present values of the hydrocarbons that could be recovered may not be sufficient to offset the capital investment. Those entities whose undiscounted net present value became negative under less favourable price and cost projections were not included in the summary tables.

The values of the reserves presented in this constant price and cost evaluation should not be taken out of context, as they were prepared to comply with the Securities & Exchange Commission's (SEC) regulations; therefore, they do not reflect our opinion of the market value of these reserves.

Table C-4 presents a summary of the various reserves categories. Table C-5 presents a summary of net present values of future net revenue, before income taxes. Table C-6 presents the total future net revenue (undiscounted) for the total proved and total proved plus probable reserves categories. Table C-7 presents the net present value of future net revenue by production group for the total proved and total proved plus probable reserves categories. Table C-8 presents the summary of pricing assumptions for constant prices and costs.

Table C-1

Eagleford Energy Inc.

Consolidation

SUMMARY OF THE EVALUATION OF THE P.& N.G. RESERVES

(As of Date: 2011-08-31)

	Remaining Reserves			Net Present Values Before Income Taxes				
	Gross 100%	Company Gross	Company Net	@ 0% M$	@ 5% M$	@ 10% M$	@ 15% M$	@ 20% M$
Non-Assoc, Assoc Gas (MMcf)								
Proved Developed Producing	2939	153	128	103	86	73	63	56
Probable Developed Producing	812	42	34	23	15	11	8	7
Total Proved+Probable	3751	195	161	126	101	84	72	63
Grand Total (Mboe)								
Proved Developed Producing	489.9	25.5	21.3	103	86	73	63	56
Probable Developed Producing	135.3	7.0	5.6	23	15	11	8	7
Total Proved+Probable	625.2	32.5	26.8	126	101	84	72	63

Table C-2

Eagleford Energy Inc.

SAL X110831 Constant-0

SUMMARY OF THE EVALUATION OF THE P.&N.G. RESERVES

(As of Date: 2011-08-31)

	Lt, Med, Heavy Oil			Non-Assoc., Assoc. Gas / Solution Gas			Natural Gas Liquids / Sulphur			Net Present Values Before Income Taxes			
	Remaining Reserves	Company Reserves Gross	Company Reserves Net	Remaining Reserves	Company Reserves Gross	Company Reserves Net	Remaining Reserves	Company Reserves Gross	Company Reserves Net	@ 0%	@ 5%	@ 10%	@ 15%
	Mbbl	Mbbl	Mbbl	MMcf MMcf	MMcf MMcf	MMcf MMcf	Mbbl MLt	Mbbl MLt	Mbbl MLt	M$	M$	M$	M$
Eagleford Energy Inc.													
PDP				2939	153	128				103	86	73	63
TP				2939	153	128				103	86	73	63
PBDP				812	42	34				23	15	11	8
TPP				3751	195	161				126	101	84	72
Botha													
PDP				2939	153	128				103	86	73	63
TP				2939	153	128				103	86	73	63
PBDP				812	42	34				23	15	11	8
TPP				3751	195	161				126	101	84	72

Table C-3

Proved+Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil Mbbl	Heavy Oil Mbbl	Solution Gas MMcf	Non-Assoc Assoc Gas MMcf	Ethane Mbbl	Propane Mbbl	Butane Mbbl	Pentanes Plus Mbbl	Total NGL Mbbl	Sulphur MLt	Equiv Oil Mboe
Gross	0.0	0.0	0	3751	0.0	0.0	0.0	0.0	0.0	0.0	625.2
Co Grs	0.0	0.0	0	195	0.0	0.0	0.0	0.0	0.0	0.0	32.5
Co Net	0.0	0.0	0	161	0.0	0.0	0.0	0.0	0.0	0.0	26.8

Net Present Value

Discount Rate %	Total Net Capital M$	Before Tax Net Rev M$	ARTC Cap GCA M$	Aband Cost M$	SK Tax Overhead M$	Before Tax Cash Flow M$
0.0	0	130	0	4	0	126
5.0	0	103	0	2	0	101
8.0	0	91	0	1	0	90
10.0	0	85	0	1	0	84
12.0	0	79	0	1	0	79
15.0	0	72	0	0	0	72
20.0	0	63	0	0	0	63
25.0	0	56	0	0	0	56

Reserve Life = 17.5 yrs Reserve Half Life = 6.0 yrs BOE Reserve Index = 10.4

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs bbl/d	Gas Comp Grs Mcf/d	BOE Comp Grs boe/d	Oil Rev M$	Gas Rev M$	Other Rev M$	Total Crown M$	Non-Crown M$	Lease Expen M$	Other Expen M$	Total Cap M$	Aband Etc M$	BTax Cash Flow M$
2011	0	52	9	0	25	0	5	0	14	0	0	0	6
2012	0	50	8	0	72	0	13	0	41	0	0	0	17
2013	0	47	8	0	67	0	12	0	39	0	0	0	15
2014	0	44	7	0	63	0	11	0	38	0	0	0	14
2015	0	41	7	0	59	0	10	0	37	0	0	0	12
2016	0	39	6	0	56	0	9	0	36	0	0	0	11
2017	0	36	6	0	52	0	8	0	34	0	0	0	10
2018	0	34	6	0	49	0	7	0	33	0	0	0	9
2019	0	32	5	0	46	0	6	0	32	0	0	0	7
2020	0	30	5	0	43	0	5	0	31	0	0	0	7
2021	0	28	5	0	40	0	4	0	30	0	0	0	6
2022	0	26	4	0	38	0	3	0	29	0	0	0	5
2023	0	25	4	0	35	0	3	0	29	0	0	0	4
2024	0	23	4	0	33	0	2	0	28	0	0	0	3
2025	0	22	4	0	31	0	2	0	27	0	0	0	2
2026	0	17	3	0	24	0	1	0	21	0	0	2	-1
2027	0	11	2	0	15	0	1	0	14	0	0	0	1
2028	0	10	2	0	15	0	1	0	14	0	0	0	0
2029	0	9	2	0	2	0	0	0	2	0	0	2	-2
Total				0	764	0	104	0	530	0	0	4	126
Discounted Cash Streams	5%			0	563	0	82	0	378	0	0	2	101
	10%			0	438	0	67	0	286	0	0	1	84
	15%			0	357	0	57	0	228	0	0	0	72
	20%			0	301	0	50	0	189	0	0	0	63

Sproule

Table C-3

Proved+Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	2	1007	123	6	5	3.92
2012	2	965	353	18	14	3.92
2013	2	904	330	17	13	3.92
2014	2	848	309	16	12	3.92
2015	2	795	290	15	12	3.92
2016	2	745	273	14	11	3.92
2017	2	698	255	13	11	3.92
2018	2	655	239	12	10	3.92
2019	2	614	224	12	10	3.92
2020	2	575	211	11	9	3.92
2021	2	539	197	10	9	3.92
2022	2	506	185	10	8	3.92
2023	2	474	173	9	8	3.92
2024	2	445	163	8	8	3.92
2025	2	417	152	8	7	3.92
2026	2	320	117	6	6	3.92
2027	1	207	76	4	4	3.92
2028	1	195	71	4	3	3.92
2029	1	183	11	1	1	3.92
Total			3751	195	161	

Table C-3

Proved+Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

	Revenue						Royalties						
Year	Oil M$	Gas M$	NGL M$	Sul M$	Roy M$	Other Income M$	Crown M$	Adjust M$	FH/ Indian M$	ORR M$	Min Taxes M$	Opex M$	NPI/ Other Expense M$
2011	0	25	0	0	0	0	5	0	0	0	0	14	0
2012	0	72	0	0	0	0	15	1	0	0	0	41	0
2013	0	67	0	0	0	0	13	1	0	0	0	39	0
2014	0	63	0	0	0	0	12	1	0	0	0	38	0
2015	0	59	0	0	0	0	11	1	0	0	0	37	0
2016	0	56	0	0	0	0	10	1	0	0	0	36	0
2017	0	52	0	0	0	0	9	1	0	0	0	34	0
2018	0	49	0	0	0	0	8	1	0	0	0	33	0
2019	0	46	0	0	0	0	7	1	0	0	0	32	0
2020	0	43	0	0	0	0	6	0	0	0	0	31	0
2021	0	40	0	0	0	0	5	0	0	0	0	30	0
2022	0	38	0	0	0	0	4	0	0	0	0	29	0
2023	0	35	0	0	0	0	3	0	0	0	0	29	0
2024	0	33	0	0	0	0	2	0	0	0	0	28	0
2025	0	31	0	0	0	0	2	0	0	0	0	27	0
2026	0	24	0	0	0	0	1	0	0	0	0	21	0
2027	0	15	0	0	0	0	1	0	0	0	0	14	0
2028	0	15	0	0	0	0	1	0	0	0	0	14	0
2029	0	2	0	0	0	0	0	0	0	0	0	2	0
Total	0	764	0	0	0	0	113	9	0	0	0	530	0

		Capital											
Year	Oper Inc M$	CEE M$	CDE M$	CCA M$	COGPE M$	Total Capital M$	Net Rev M$	Cum Net Rev M$	ARTC M$	Aband Cost M$	SK Tax M$	Cash Flow M$	Cum Cash Flow M$
2011	6	0	0	0	0	0	6	6	0	0	0	6	6
2012	17	0	0	0	0	0	17	24	0	0	0	17	24
2013	15	0	0	0	0	0	15	39	0	0	0	15	39
2014	14	0	0	0	0	0	14	53	0	0	0	14	53
2015	12	0	0	0	0	0	12	66	0	0	0	12	66
2016	11	0	0	0	0	0	11	76	0	0	0	11	76
2017	10	0	0	0	0	0	10	86	0	0	0	10	86
2018	9	0	0	0	0	0	9	95	0	0	0	9	95
2019	7	0	0	0	0	0	7	102	0	0	0	7	102
2020	7	0	0	0	0	0	7	109	0	0	0	7	109
2021	6	0	0	0	0	0	6	114	0	0	0	6	114
2022	5	0	0	0	0	0	5	119	0	0	0	5	119
2023	4	0	0	0	0	0	4	123	0	0	0	4	123
2024	3	0	0	0	0	0	3	126	0	0	0	3	126
2025	2	0	0	0	0	0	2	128	0	0	0	2	128
2026	1	0	0	0	0	0	1	129	0	2	0	-1	127
2027	1	0	0	0	0	0	1	130	0	0	0	1	128
2028	0	0	0	0	0	0	0	130	0	0	0	0	128
2029	0	0	0	0	0	0	0	130	0	2	0	-2	126
Total	130	0	0	0	0	0	130		0	4	0	126	

	Discounted Cash Streams NPV (M$)						
discR%	5	10	12	15	18	20	25
BT Net	103	85	79	72	66	63	56
BT Cash Flow	101	84	79	72	66	63	56

Table C-3A

Proved Developed Producing

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil	Heavy Oil	Solution Gas	Non-Assoc Assoc Gas	Ethane	Propane	Butane	Pentanes Plus	Total NGL	Sulphur	Equiv Oil
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MLt	Mboe
Gross	0.0	0.0	0	2939	0.0	0.0	0.0	0.0	0.0	0.0	489.9
Co Grs	0.0	0.0	0	153	0.0	0.0	0.0	0.0	0.0	0.0	25.5
Co Net	0.0	0.0	0	128	0.0	0.0	0.0	0.0	0.0	0.0	21.3

Net Present Value

Discount Rate	Total Net Capital	Before Tax Net Rev	ARTC Cap GCA	Aband Cost	SK Tax Overhead	Before Tax Cash Flow
%	M$	M$	M$	M$	M$	M$
0.0	0	107	0	4	0	103
5.0	0	88	0	2	0	86
8.0	0	79	0	1	0	78
10.0	0	74	0	1	0	73
12.0	0	70	0	1	0	69
15.0	0	64	0	1	0	63
20.0	0	56	0	0	0	56
25.0	0	50	0	0	0	50

Reserve Life = 15.0 yrs   Reserve Half Life = 4.9 yrs   BOE Reserve Index = 8.5

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs	Gas Comp Grs	BOE Comp Grs	Oil Rev	Gas Rev	Other Rev	Total Crown	Non-Crown	Lease Expen	Other Expen	Total Cap	Aband Etc	BTax Cash Flow
	bbl/d	Mcf/d	boe/d	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	51	8	0	24	0	4	0	14	0	0	0	6
2012	0	48	8	0	69	0	13	0	40	0	0	0	17
2013	0	44	7	0	63	0	11	0	38	0	0	0	14
2014	0	41	7	0	58	0	10	0	36	0	0	0	13
2015	0	37	6	0	53	0	8	0	34	0	0	0	11
2016	0	34	6	0	49	0	7	0	33	0	0	0	10
2017	0	32	5	0	45	0	6	0	31	0	0	0	8
2018	0	29	5	0	42	0	5	0	30	0	0	0	7
2019	0	27	4	0	38	0	4	0	28	0	0	0	6
2020	0	25	4	0	35	0	3	0	27	0	0	0	5
2021	0	23	4	0	32	0	2	0	26	0	0	0	4
2022	0	21	3	0	30	0	2	0	25	0	0	0	3
2023	0	15	3	0	22	0	1	0	19	0	0	2	0
2024	0	10	2	0	15	0	1	0	13	0	0	0	1
2025	0	10	2	0	14	0	1	0	13	0	0	0	1
2026	0	9	1	0	9	0	0	0	8	0	0	2	-2
Total				0	599	0	77	0	414	0	0	4	103
Discounted Cash Streams	5%			0	464	0	64	0	312	0	0	2	86
	10%			0	375	0	54	0	246	0	0	1	73
	15%			0	313	0	47	0	202	0	0	1	63
	20%			0	269	0	42	0	170	0	0	0	56

Sproule

Table C-3A

Proved Developed Producing

Eagleford Energy Inc.

Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	2	974	119	6	5	3.92
2012	2	922	337	18	13	3.92
2013	2	848	310	16	12	3.92
2014	2	780	285	15	12	3.92
2015	2	718	262	14	11	3.92
2016	2	661	242	13	10	3.92
2017	2	608	222	12	10	3.92
2018	2	560	204	11	9	3.92
2019	2	515	188	10	9	3.92
2020	2	474	174	9	8	3.92
2021	2	437	159	8	8	3.92
2022	2	402	147	8	7	3.92
2023	2	294	107	6	5	3.92
2024	1	201	74	4	4	3.92
2025	1	186	68	4	3	3.92
2026	1	171	42	2	2	3.92
Total			2939	153	128	

Table C-3A

Proved Developed Producing

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil (Revenue)	Gas (Revenue)	NGL (Revenue)	Sul (Revenue)	Roy (Revenue)	Other Income (Revenue)	Crown (Royalties)	Adjust (Royalties)	FH/ Indian (Royalties)	ORR (Royalties)	Min Taxes	Opex	NPI/ Other Expense
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	24	0	0	0	0	5	0	0	0	0	14	0
2012	0	69	0	0	0	0	14	1	0	0	0	40	0
2013	0	63	0	0	0	0	12	1	0	0	0	38	0
2014	0	58	0	0	0	0	11	1	0	0	0	36	0
2015	0	53	0	0	0	0	9	1	0	0	0	34	0
2016	0	49	0	0	0	0	8	1	0	0	0	33	0
2017	0	45	0	0	0	0	6	1	0	0	0	31	0
2018	0	42	0	0	0	0	5	0	0	0	0	30	0
2019	0	38	0	0	0	0	4	0	0	0	0	28	0
2020	0	35	0	0	0	0	3	0	0	0	0	27	0
2021	0	32	0	0	0	0	2	0	0	0	0	26	0
2022	0	30	0	0	0	0	2	0	0	0	0	25	0
2023	0	22	0	0	0	0	1	0	0	0	0	19	0
2024	0	15	0	0	0	0	1	0	0	0	0	13	0
2025	0	14	0	0	0	0	1	0	0	0	0	13	0
2026	0	9	0	0	0	0	0	0	0	0	0	8	0
Total	0	599	0	0	0	0	84	7	0	0	0	414	0

Year	Oper Inc	CEE (Capital)	CDE (Capital)	CCA (Capital)	COGPE (Capital)	Total Capital	Net Rev	Cum Net Rev	ARTC	Aband Cost	SK Tax	Cash Flow	Cum Cash Flow
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	6	0	0	0	0	0	6	6	0	0	0	6	6
2012	17	0	0	0	0	0	17	23	0	0	0	17	23
2013	14	0	0	0	0	0	14	37	0	0	0	14	37
2014	13	0	0	0	0	0	13	50	0	0	0	13	50
2015	11	0	0	0	0	0	11	61	0	0	0	11	61
2016	10	0	0	0	0	0	10	70	0	0	0	10	70
2017	8	0	0	0	0	0	8	79	0	0	0	8	79
2018	7	0	0	0	0	0	7	86	0	0	0	7	86
2019	6	0	0	0	0	0	6	92	0	0	0	6	92
2020	5	0	0	0	0	0	5	97	0	0	0	5	97
2021	4	0	0	0	0	0	4	101	0	0	0	4	101
2022	3	0	0	0	0	0	3	104	0	0	0	3	104
2023	2	0	0	0	0	0	2	105	0	2	0	0	103
2024	1	0	0	0	0	0	1	107	0	0	0	1	105
2025	1	0	0	0	0	0	1	107	0	0	0	1	105
2026	0	0	0	0	0	0	0	107	0	2	0	-2	103
Total	107	0	0	0	0	0	107		0	4	0	103	

Discounted Cash Streams NPV (M$)

discR%	5	10	12	15	18	20	25
BT Net	88	74	70	64	59	56	50
BT Cash Flow	86	73	69	63	59	56	50

Table C-3B

Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil Mbbl	Heavy Oil Mbbl	Solution Gas MMcf	Non-Assoc Assoc Gas MMcf	Ethane Mbbl	Propane Mbbl	Butane Mbbl	Pentanes Plus Mbbl	Total NGL Mbbl	Sulphur MLt	Equiv Oil Mboe
Gross	0.0	0.0	0	812	0.0	0.0	0.0	0.0	0.0	0.0	135.3
Co Grs	0.0	0.0	0	42	0.0	0.0	0.0	0.0	0.0	0.0	7.0
Co Net	0.0	0.0	0	34	0.0	0.0	0.0	0.0	0.0	0.0	5.6

Net Present Value

Discount Rate %	Total Net Capital M$	Before Tax Net Rev M$	ARTC Cap GCA M$	Aband Cost M$	SK Tax Overhead M$	Before Tax Cash Flow M$
0.0	0	23	0	0	0	23
5.0	0	15	0	0	0	15
8.0	0	12	0	0	0	13
10.0	0	11	0	0	0	11
12.0	0	10	0	0	0	10
15.0	0	8	0	0	0	8
20.0	0	6	0	0	0	7
25.0	0	5	0	0	0	5

Reserve Life = 17.5 yrs Reserve Half Life = 12.3 yrs BOE Reserve Index = 57.5

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year		Oil Comp Grs bbl/d	Gas Comp Grs Mcf/d	BOE Comp Grs boe/d	Oil Rev M$	Gas Rev M$	Other Rev M$	Total Crown M$	Non-Crown M$	Lease Expen M$	Other Expen M$	Total Cap M$	Aband Etc M$	BTax Cash Flow M$
2011		0	2	0	0	1	0	0	0	0	0	0	0	0
2012		0	2	0	0	3	0	1	0	1	0	0	0	1
2013		0	3	0	0	4	0	1	0	2	0	0	0	1
2014		0	4	1	0	5	0	1	0	2	0	0	0	1
2015		0	4	1	0	6	0	2	0	3	0	0	0	1
2016		0	4	1	0	6	0	2	0	3	0	0	0	1
2017		0	5	1	0	7	0	2	0	3	0	0	0	1
2018		0	5	1	0	7	0	2	0	4	0	0	0	1
2019		0	5	1	0	7	0	2	0	4	0	0	0	1
2020		0	5	1	0	8	0	2	0	4	0	0	0	1
2021		0	5	1	0	8	0	2	0	4	0	0	0	2
2022		0	5	1	0	8	0	2	0	4	0	0	0	2
2023		0	9	2	0	13	0	2	0	10	0	0	-2	4
2024		0	13	2	0	18	0	2	0	15	0	0	0	2
2025		0	12	2	0	17	0	1	0	14	0	0	0	1
2026		0	11	2	0	15	0	1	0	13	0	0	0	1
2027		0	11	2	0	15	0	1	0	14	0	0	0	1
2028		0	10	2	0	15	0	1	0	14	0	0	0	0
2029		0	9	2	0	2	0	0	0	2	0	0	2	-2
Total					0	165	0	26	0	116	0	0	0	23
Discounted	5%				0	99	0	18	0	66	0	0	0	15
Cash	10%				0	64	0	13	0	40	0	0	0	11
Streams	15%				0	44	0	10	0	26	0	0	0	8
	20%				0	32	0	8	0	18	0	0	0	7

Table C-3B

Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily	Gas Gross	Gas Co Grs	Gas Co Net	Gas Price
		Mcf/d	MMcf	MMcf	MMcf	$/Mcf
2011	0	34	4	0	0	3.92
2012	0	43	16	1	1	3.92
2013	0	57	21	1	1	3.92
2014	0	68	25	1	1	3.92
2015	0	77	28	1	1	3.92
2016	0	84	31	2	1	3.92
2017	0	90	33	2	1	3.92
2018	0	95	35	2	1	3.92
2019	0	98	36	2	1	3.92
2020	0	101	37	2	1	3.92
2021	0	103	38	2	1	3.92
2022	0	104	38	2	1	3.92
2023	0	180	66	3	3	3.92
2024	1	243	89	5	4	3.92
2025	1	231	84	4	4	3.92
2026	1	205	75	4	4	3.92
2027	1	207	76	4	4	3.92
2028	1	195	71	4	3	3.92
2029	1	183	11	1	1	3.92
Total			812	42	34	

Table C-3B

Probable

Eagleford Energy Inc.

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

	Revenue						Royalties						
Year	Oil	Gas	NGL	Sul	Roy	Other Income	Crown	Adjust	FH/ Indian	ORR	Min Taxes	Opex	NPI/ Other Expense
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	1	0	0	0	0	0	0	0	0	0	0	0
2012	0	3	0	0	0	0	1	0	0	0	0	1	0
2013	0	4	0	0	0	0	1	0	0	0	0	2	0
2014	0	5	0	0	0	0	1	0	0	0	0	2	0
2015	0	6	0	0	0	0	2	0	0	0	0	3	0
2016	0	6	0	0	0	0	2	0	0	0	0	3	0
2017	0	7	0	0	0	0	2	0	0	0	0	3	0
2018	0	7	0	0	0	0	2	0	0	0	0	4	0
2019	0	7	0	0	0	0	2	0	0	0	0	4	0
2020	0	8	0	0	0	0	2	0	0	0	0	4	0
2021	0	8	0	0	0	0	2	0	0	0	0	4	0
2022	0	8	0	0	0	0	2	0	0	0	0	4	0
2023	0	13	0	0	0	0	2	0	0	0	0	10	0
2024	0	18	0	0	0	0	2	0	0	0	0	15	0
2025	0	17	0	0	0	0	1	0	0	0	0	14	0
2026	0	15	0	0	0	0	1	0	0	0	0	13	0
2027	0	15	0	0	0	0	1	0	0	0	0	14	0
2028	0	15	0	0	0	0	1	0	0	0	0	14	0
2029	0	2	0	0	0	0	0	0	0	0	0	2	0
Total	0	165	0	0	0	0	29	2	0	0	0	116	0

		Capital											
Year	Oper Inc	CEE	CDE	CCA	COGPE	Total Capital	Net Rev	Cum Net Rev	ARTC	Aband Cost	SK Tax	Cash Flow	Cum Cash Flow
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	1	0	0	0	0	0	1	1	0	0	0	1	1
2013	1	0	0	0	0	0	1	2	0	0	0	1	2
2014	1	0	0	0	0	0	1	4	0	0	0	1	4
2015	1	0	0	0	0	0	1	5	0	0	0	1	5
2016	1	0	0	0	0	0	1	6	0	0	0	1	6
2017	1	0	0	0	0	0	1	7	0	0	0	1	7
2018	1	0	0	0	0	0	1	9	0	0	0	1	9
2019	1	0	0	0	0	0	1	10	0	0	0	1	10
2020	1	0	0	0	0	0	1	12	0	0	0	1	12
2021	2	0	0	0	0	0	2	13	0	0	0	2	13
2022	2	0	0	0	0	0	2	15	0	0	0	2	15
2023	2	0	0	0	0	0	2	17	0	-2	0	4	19
2024	2	0	0	0	0	0	2	19	0	0	0	2	21
2025	1	0	0	0	0	0	1	21	0	0	0	1	23
2026	1	0	0	0	0	0	1	22	0	0	0	1	24
2027	1	0	0	0	0	0	1	22	0	0	0	1	24
2028	0	0	0	0	0	0	0	23	0	0	0	0	25
2029	0	0	0	0	0	0	0	23	0	2	0	-2	23
Total	23	0	0	0	0	0	23		0	0	0	23	

	Discounted Cash Streams NPV (M$)						
discR%	5	10	12	15	18	20	25
BT Net	15	11	10	8	7	6	5
BT Cash Flow	15	11	10	8	7	7	5

Table C-4
NI 51-101
Summary of Oil and Gas Reserves
as of August 31, 2011
Constant Prices and Costs

Reserves

	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated & associated)		Natural Gas Liquids	
Reserve Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved								
Developed Producing	0.0	0.0	0.0	0.0	153	128	0.0	0.0
Developed Non-Producing	0.0	0.0	0.0	0.0	0	0	0.0	0.0
Undeveloped	0.0	0.0	0.0	0.0	0	0	0.0	0.0
Total Proved	**0.0**	**0.0**	**0.0**	**0.0**	**153**	**128**	**0.0**	**0.0**
Probable	0.0	0.0	0.0	0.0	42	34	0.0	0.0
Total Proved Plus Probable	**0.0**	**0.0**	**0.0**	**0.0**	**195**	**161**	**0.0**	**0.0**

Reference: Item 2.2(1) of Form 51-101F1

Table C-5
NI 51-101
Summary of Net Present Values of Future Net Revenue
As of August 31, 2011
Constant Prices and Costs

	Net Present Values of Future Net Revenue					
	Before Income Taxes Discounted at (% / Year)					Unit Value Before Income Tax Discounted at 10% / Year
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**$ / BOE**
Proved						
Developed Producing	103	86	73	63	56	3.43
Developed Non-Producing	0	0	0	0	0	0.00
Undeveloped	0	0	0	0	0	0.00
Total Proved	**103**	**86**	**73**	**63**	**56**	**3.43**
Probable	23	15	11	8	7	1.98
Total Proved Plus Probable	**126**	**101**	**84**	**72**	**63**	**3.13**

Reference Item 2.2(2) of Form 51-101F1

Notes:

- NPV of FNR include all resource income:
  - Sale of oil, gas, by-product reserves
  - Processing third party reserves
  - Other income
- Income Taxes
  - Includes all resource income
  - Apply appropriate income tax calculations
  - Include prior tax pools
- Unit Values are based on net reserve volumes

Table C-6
Total Future Net Revenue
(Undiscounted)
As of August 31, 2011
Constant Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)
Proved	599	77	414	0	4	103
Proved Plus Probable	764	104	530	0	4	126

Reference Item 2.1(3)(b) of Form 51-101F1

Table C-7
NI 51-101
Net Present Value of Future Net Revenue by Production Group as of August 31, 2011
Constant Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Unit Value Before Income Taxes (Discounted at 10%/Year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)*	73	3.43
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)*	84	3.13

Reference Item 2.1(3)(c) of Form 51-101F1
* Includes corporate Capital GCA, if applicable
Unit Values are based on net reserve volumes

Table C-8
NI 51-101
Summary of Pricing Assumptions
as of August 31, 2011
Constant Prices and Costs

	Oil			Gas	NGLs		
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas[1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes F.O.B. Field Gate ($Cdn/bbl)	Exchange Rate ($US/$Cdn)
Historical							
Aug. 31, 2005	68.95	87.14	57.68	11.09	81.36	47.48	0.842
Aug. 31, 2006	70.27	70.98	83.11	5.07	70.34	65.11	0.904
Aug. 31, 2007	74.04	76.44	73.52	4.65	79.19	63.52	0.947
Aug. 31, 2008	115.46	122.15	113.47	7.12	122.58	83.38	0.942
Aug. 31, 2009	69.96	73.41	67.48	2.34	73.90	57.97	0.913
Aug. 31, 2010	71.92	73.22	70.05	3.34	75.01	51.22	0.940
Constant							
Aug. 31, 2011	96.20	90.95	87.74	3.77	96.73	69.59	1.010

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.

Notes:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

National Instrument 51-101

This report was prepared for the purpose of evaluating the Company's P&NG reserves according to the Canadian Oil and Gas Evaluation Handbook (COGEH) reserve definitions and standards, which are consistent with National Instrument 51-101 (NI 51-101). In accordance with these standards, and by reference in NI 51-101, certain tables are presented for the forecast prices and costs case, which summarize the reserves and net present values, as of August 31, 2011.

Form 51-101F2, which follows, presents a Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor.

Forecast Prices and Costs

Table 1 presents a summary of the various reserves categories. Table 2 presents a summary of net present values of future net revenue, before taxes. Table 3 presents the total future net revenue (undiscounted) for the total proved and total proved plus probable reserves categories. Table 4 presents the net present value of future net revenue by production group for the total proved and total proved plus probable reserves categories. Table 5 presents a summary of pricing and inflation rate assumptions.

Reconciliation

Table 6 presents the Reconciliation of the Company's Gross Reserves (Before Royalty) by Principal Product Type, using forecast prices and costs.

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Eagleford Energy Inc. (the "Company"):

1. We have evaluated the Company's Reserves Data as at August 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at August 31, 2011, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of August 31, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of Eagleford Energy Inc., As of August 31, 2011, prepared in September and October 2011	Canada				
Total			**Nil**	**243**	**Nil**	**243**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
October 7, 2011

Original Signed by Attila A. Szabo, P.Eng.

Attila A. Szabo, P.Eng.,
Project Leader,
Senior Petroleum Engineer and Partner

Original Signed by Harry J. Helwerda, P.Eng., FEC

Harry J. Helwerda, P.Eng., FEC
Executive Vice-President and Director

Table 1
NI 51-101
Summary of Oil and Gas Reserves
as of August 31, 2011
Forecast Prices and Costs

Reserves

	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated & associated)		Natural Gas Liquids	
Reserve Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved								
Developed Producing	0.0	0.0	0.0	0.0	203	161	0.0	0.0
Developed Non-Producing	0.0	0.0	0.0	0.0	0	0	0.0	0.0
Undeveloped	0.0	0.0	0.0	0.0	0	0	0.0	0.0
Total Proved	**0.0**	**0.0**	**0.0**	**0.0**	**203**	**161**	**0.0**	**0.0**
Probable	0.0	0.0	0.0	0.0	66	49	0.0	0.0
Total Proved Plus Probable	**0.0**	**0.0**	**0.0**	**0.0**	**269**	**211**	**0.0**	**0.0**

Reference: Item 2.2(1) of Form 51-101F1

Table 2 NI 51-101 Summary of Net Present Values of Future Net Revenue As of August 31, 2011 Forecast Prices and Costs						
	Net Present Values of Future Net Revenue					
	Before Income Taxes Discounted at (%/Year)					Unit Value Before Income Tax Discounted at 10%/Year
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**$/BOE**
Proved						
Developed Producing	444	288	205	155	124	7.60
Developed Non-Producing	0	0	0	0	0	0.00
Undeveloped	0	0	0	0	0	0.00
Total Proved	**444**	**288**	**205**	**155**	**124**	**7.60**
Probable	182	77	39	23	15	4.74
Total Proved Plus Probable	**626**	**365**	**243**	**178**	**139**	**6.93**

Reference Item 2.2(2) of Form 51-101F1

Notes: NPV of FNR include all resource income:

- Sale of oil, gas, by-product reserves
- Processing third party reserves
- Other income

Unit Values are based on net reserve volumes

Table 3
NI 51-101
Total Future Net Revenue
(Undiscounted)
As of August 31, 2011
Forecast Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)
Proved	1,400	228	722	0	5	444
Proved Plus Probable	2,001	349	1,020	0	6	626

Reference Item 2.2(3)(b) of Form 51-101F1

Table 4
NI 51-101
Net Present Value of Future Net Revenue by Production Group as of August 31, 2011
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Unit Value Before Income Taxes (Discounted at 10%/Year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)*	205	7.60
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)*	243	6.93

Reference Item 2.1(3)(c) of Form 51-101F1
* Includes corporate Capital GCA, if applicable
Unit Values are based on net reserve volumes

Table 5
NI 51-101
Summary of Pricing and
Inflation Rate Assumptions
as of August 31, 2011
Forecast Prices and Costs

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas[1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes F.O.B. Field Gate ($Cdn/bbl)	Inflation Rate[2] (%/Yr)	Exchange Rate[3] ($US/$Cdn)
Historical								
2007	72.27	77.06	65.36	6.65	77.33	63.71	2.0	0.935
2008	99.59	102.85	93.05	8.15	104.70	75.09	1.0	0.943
2009	61.63	66.20	62.77	4.19	68.13	44.13	2.0	0.880
2010	79.43	77.80	73.67	4.16	84.21	57.04	1.0	0.971
Forecast								
2011	90.28	87.42	84.42	3.55	93.46	78.92	2.0	1.012
2012	93.23	90.32	87.32	3.94	96.57	81.54	2.0	1.012
2013	95.58	92.62	89.62	4.41	99.03	83.62	2.0	1.012
2014	95.97	92.99	89.99	5.21	99.42	83.96	2.0	1.012
2015	97.42	94.41	91.41	6.43	100.93	85.23	2.0	1.012
2016	99.37	96.32	93.32	6.57	102.97	86.95	2.0	1.012
2017	101.35	98.26	95.26	6.71	105.05	88.71	2.0	1.012
2018	103.38	100.25	97.25	6.86	107.17	90.50	2.0	1.012
2019	105.45	102.27	99.27	7.00	109.34	92.33	2.0	1.012
2020	107.56	104.33	101.33	7.15	111.55	94.19	2.0	1.012
2021	109.71	106.44	103.44	7.31	113.80	96.10	2.0	1.012
Thereafter				Escalation Rate of 2%				

(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.

Notes:

Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Reference Item 3.2 of Form 51-101F1

Table 6
NI 51-101
Reconciliation of Company Gross[1] Reserves (Before Royalty)
by Principal Product Type
As of August 31, 2011
Forecast Prices and Costs

	Light and Medium Oil			Heavy Oil			Coalbed Methane			Associated and Non-Associated Gas			Natural Gas Solution			Natural Gas Liquids		
Factors	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**
August 31, 2009	-	-	-	-	-	-	-	-	-	213	69	282	-	-	-	-	-	-
Extensions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	9	(3)	6	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	(19)	-	(19)	-	-	-	-	-	-
August 31, 2010	-	-	-	-	-	-	-	-	-	203	66	269	-	-	-	-	-	-

(1) Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.

Reference: Item 4.1 of Form 51-101F1

Eagleford Energy Inc.

Botha

SUMMARY OF THE EVALUATION OF THE P.& N.G. RESERVES

(As of Date: 2011-08-31)

	Remaining Reserves			Net Present Values Before Income Taxes				
	Gross	Company						
	100%	Gross	Net	@ 0%	@ 5%	@ 10%	@ 15%	@ 20%
				M$	M$	M$	M$	M$
Non-Assoc, Assoc Gas (MMcf)								
Proved Developed Producing	3901	203	161	444	288	205	155	124
Probable Developed Producing	1276	66	49	182	77	39	23	15
Total Proved+Probable	5177	269	211	626	365	243	178	139
Grand Total (Mboe)								
Proved Developed Producing	650.1	33.8	26.9	444	288	205	155	124
Probable Developed Producing	212.7	11.1	8.2	182	77	39	23	15
Total Proved+Probable	862.9	44.8	35.1	626	365	243	178	139

Pertinent Data

Eagleford Energy Inc.

Botha

Land: WI of 5.1975% on all entities.
Crown on all entities with royalty categories of 2011

Reserves Estimation: Gas by Decline (2 cases) on PDP
Gas by Decline (2 cases) on PPDP

Gas Production Rates:

Proved Developed Producing	Zone	Init. Sales R Mcf/d	NGL/Sales G bbl/MMcf
100/06-14-098-05W6/0	Debolt A	543 (11-09)	0.0
102/06-22-098-05W6/0	Debolt A	441 (11-09)	0.0

P2 Developed Producing	Zone	Init. Sales R Mcf/d	NGL/Sales G bbl/MMcf
100/06-14-098-05W6/0	Debolt A	544 (11-09)	0.0
102/06-22-098-05W6/0	Debolt A	472 (11-09)	0.0

Operating Costs (2011$'s)

Gas:

Proved Developed Producing

100/06-14-098-05W6/0 — $6450 per well per month.
102/06-22-098-05W6/0 — $1.76 per Mcf of sales gas.
$0.25 GCA/Process Fee per Mcf of sales gas

P2 Developed Producing

100/06-14-098-05W6/0 — $6450 per well per month.
102/06-22-098-05W6/0 — $1.76 per Mcf of sales gas.
$0.25 GCA/Process Fee per Mcf of sales gas

Prices: AECO-C Spot Gas price with an increase of $.15 per MMbtu, with heating value of 1000

Abandonment: M$30 on all entities.

Eagleford Energy Inc.

Botha

Pertinent Data Well List

(As of Date: 2011-08-31)

Entity	ResCat	Oil Gas Cash	ProdSt	Qf	WI	RI	CrR	Non CrR	Min Tax	Grs IntR	Init Wells	Surf Loss	Sales GOR	Sales NglR	Fix / Var Expense Boe		Cap Exp	Aband Exp	Oth. Inc.	ITaxR	Life
			yy/mm	/day	%	%	%	%	%	boe/d		%	scf/bbl	bbl/MMcf	$/boe		M$	M$	M$	%	Yrs
100/06-14-098-05W6/0	PDP	Gas	11-09	5	5.2	0.0	18.1	0.0	0.0	90	1.0	15.0	0	0.0	2.36	10.59	0	54	0.00	25.0	30.2
100/06-14-098-05W6/0	PPDP	Gas	11-09	5	5.2	0.0	18.1	0.0	0.0	91	1.0	15.0	0	0.0	2.35	10.59	0	64	0.00	25.0	38.3
100/09-21-098-05W6/0	PDP	Gas	11-09	5	0.0	0.0	0.0	0.0	0.0	0	0.0	15.0	0	0.0	0.00	0.00	0	0	0.00	0.0	0.0
100/09-21-098-05W6/0	PPDP	Gas	11-09	5	0.0	0.0	0.0	0.0	0.0	0	0.0	15.0	0	0.0	0.00	0.00	0	0	0.00	0.0	0.0
102/06-22-098-05W6/0	PDP	Gas	11-09	5	5.2	0.0	16.9	0.0	0.0	74	1.0	15.0	0	0.0	2.91	10.59	0	48	0.00	25.0	23.8
102/06-22-098-05W6/0	PPDP	Gas	11-09	5	5.2	0.0	17.7	0.0	0.0	79	1.0	15.0	0	0.0	2.71	10.59	0	57	0.00	25.0	32.0

Table 1

Eagleford Energy Inc.

Botha,

WELL LIST / RESERVOIR DATA

GAS RESERVES

Location	Reserve Category	Analysis Type	Drainage Area	Net Pay	Poros.	Water Sat	Temp.	Press.	Comp.	Original Gas In-Place	Recov. Factor	Original Recoverable Raw Gas
			ac	ft	%	%	degF	psia	z	MMcf	%	MMcf
100/10-10-098-05W6/0	NRA											0
100/06-14-098-05W6/0	PDP	Decline										13295 *
100/06-14-098-05W6/0	PPDP	Decline										13997 *
100/07-15-098-05W6/0	NRA											0
100/07-16-098-05W6/0	NRA											0
100/16-17-098-05W6/0	NRA											0
100/10-20-098-05W6/0	NRA											0
100/09-21-098-05W6/0	NRA											0
102/06-22-098-05W6/0	PDP	Decline										7546 *
102/06-22-098-05W6/0	PPDP	Decline										8318 *
Total Technical Reserves												22315
Adjusted To Econ. Reserves												21886

* Reserves have been adjusted for economics.

Table 2

Eagleford Energy Inc.

Botha

ESTIMATES OF RESERVES AND NET PRESENT VALUES

(As of Date: 2011-08-31)

NON-ASSOC. & ASSOC. GAS RESERVES

Location / Pool		Analysis Type	Original Recoverable Raw Gas	Cum Prod	Remaining Recoverable Raw Gas	Surface Loss	Remaining Sales Gas	Initial Working Interest	Company Gross Sales Gas	Burdens	Company Net Sales Gas	NPV Before Tax 0%	NPV Before Tax 5%	NPV Before Tax 10%	NPV Before Tax 15%
			MMcf	MMcf	MMcf	%	MMcf	%	MMcf		MMcf	M$	M$	M$	M$
100/06-14-098-05W6/0 (1)															
Debolt A	(PDP)	Decline	13066	10341	2724	15.0	2316	5.20	120	Crown	94	269	169	117	88
100/06-14-098-05W6/0 (1)															
Debolt A	(PPDP)	Decline	13804	10341	3463	15.0	2943	5.20	153	Crown	118	361	204	134	97
102/06-22-098-05W6/0 (1)															
Debolt A	(PDP)	Decline	7319	5454	1865	15.0	1585	5.20	82	Crown	67	175	119	87	67
102/06-22-098-05W6/0 (1)															
Debolt A	(PPDP)	Decline	8082	5454	2628	15.0	2234	5.20	116	Crown	93	265	161	110	81
Total PDP			20385	15795	4589		3901		203		161	444	288	205	155
Total PBDP			1502	0	1502		1276		66		49	182	77	39	23
Total Prov+Prob			21886	15795	6091		5177		269		211	626	365	243	178

(1) Adjusted for Economics

Sproule

Table 3

Proved+Probable

Eagleford Energy Inc.

Botha

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil	Heavy Oil	Solution Gas	Non-Assoc Assoc Gas	Ethane	Propane	Butane	Pentanes Plus	Total NGL	Sulphur	Equiv Oil
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MLt	Mboe
Gross	0.0	0.0	0	5177	0.0	0.0	0.0	0.0	0.0	0.0	862.9
Co Grs	0.0	0.0	0	269	0.0	0.0	0.0	0.0	0.0	0.0	44.8
Co Net	0.0	0.0	0	211	0.0	0.0	0.0	0.0	0.0	0.0	35.1

Net Present Value

Discount Rate	Total Net Capital	Before Tax Net Rev	ARTC Cap GCA	Aband Cost	SK Tax Overhead	Before Tax Cash Flow
%	M$	M$	M$	M$	M$	M$
0.0	0	633	0	6	0	626
5.0	0	366	0	1	0	365
8.0	0	283	0	0	0	282
10.0	0	244	0	0	0	243
12.0	0	213	0	0	0	213
15.0	0	178	0	0	0	178
20.0	0	139	0	0	0	139
25.0	0	113	0	0	0	113

Reserve Life = 38.2 yrs Reserve Half Life = 9.2 yrs BOE Reserve Index = 14.3

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs	Gas Comp Grs	BOE Comp Grs	Oil Rev	Gas Rev	Other Rev	Total Crown	Non-Crown	Lease Expen	Other Expen	Total Cap	Aband Etc	BTax Cash Flow
	bbl/d	Mcf/d	boe/d	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	52	9	0	24	0	4	0	14	0	0	0	5
2012	0	50	8	0	75	0	15	0	41	0	0	0	19
2013	0	47	8	0	78	0	17	0	40	0	0	0	22
2014	0	44	7	0	86	0	21	0	39	0	0	0	27
2015	0	41	7	0	99	0	27	0	38	0	0	0	34
2016	0	39	6	0	95	0	26	0	36	0	0	0	33
2017	0	36	6	0	91	0	24	0	35	0	0	0	32
2018	0	34	6	0	87	0	22	0	34	0	0	0	30
2019	0	32	5	0	83	0	21	0	34	0	0	0	29
2020	0	30	5	0	80	0	19	0	33	0	0	0	28
2021	0	28	5	0	76	0	17	0	32	0	0	0	28
2022	0	26	4	0	73	0	15	0	31	0	0	0	27
2023	0	25	4	0	70	0	14	0	30	0	0	0	26
2024	0	23	4	0	67	0	13	0	30	0	0	0	25
2025	0	22	4	0	64	0	11	0	29	0	0	0	23
2026	0	20	3	0	61	0	10	0	28	0	0	0	22
2027	0	19	3	0	58	0	9	0	28	0	0	0	21
2028	0	18	3	0	56	0	8	0	27	0	0	0	20
2029	0	17	3	0	53	0	7	0	27	0	0	0	19
2030	0	16	3	0	51	0	7	0	26	0	0	0	18
SubT				0	1428	0	306	0	633	0	0	0	489
19yr				0	574	0	42	0	387	0	0	6	138
Total				0	2001	0	349	0	1020	0	0	6	626
Discounted 5%				0	1121	0	226	0	530	0	0	1	365
Cash 10%				0	747	0	162	0	342	0	0	0	243
Streams 15%				0	554	0	124	0	251	0	0	0	178
20%				0	439	0	100	0	200	0	0	0	139

Table 3

Proved+Probable

Eagleford Energy Inc.

Botha

Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	2	1007	123	6	5	3.70
2012	2	965	353	18	14	4.09
2013	2	904	330	17	13	4.56
2014	2	848	309	16	11	5.36
2015	2	795	290	15	10	6.58
2016	2	745	273	14	10	6.72
2017	2	698	255	13	9	6.86
2018	2	655	239	12	9	7.01
2019	2	614	224	12	8	7.15
2020	2	575	211	11	8	7.30
2021	2	539	197	10	8	7.46
2022	2	506	185	10	7	7.61
2023	2	474	173	9	7	7.76
2024	2	445	163	8	7	7.91
2025	2	417	152	8	6	8.06
2026	2	391	143	7	6	8.22
2027	2	366	134	7	6	8.38
2028	2	343	126	7	5	8.55
2029	2	322	118	6	5	8.71
2030	2	302	110	6	5	8.89
SubT			4106	213	160	
19yr			1071	56	51	
Total			5177	269	211	

Table 3

Proved+Probable

Eagleford Energy Inc.

Botha

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

	Revenue						Royalties						
Year	Oil	Gas	NGL	Sul	Roy	Other Income	Crown	Adjust	FH/ Indian	ORR	Min Taxes	Opex	NPI/ Other Expense
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	24	0	0	0	0	5	0	0	0	0	14	0
2012	0	75	0	0	0	0	16	1	0	0	0	41	0
2013	0	78	0	0	0	0	18	1	0	0	0	40	0
2014	0	86	0	0	0	0	22	1	0	0	0	39	0
2015	0	99	0	0	0	0	29	1	0	0	0	38	0
2016	0	95	0	0	0	0	27	1	0	0	0	36	0
2017	0	91	0	0	0	0	25	1	0	0	0	35	0
2018	0	87	0	0	0	0	23	1	0	0	0	34	0
2019	0	83	0	0	0	0	21	1	0	0	0	34	0
2020	0	80	0	0	0	0	20	1	0	0	0	33	0
2021	0	76	0	0	0	0	18	1	0	0	0	32	0
2022	0	73	0	0	0	0	16	1	0	0	0	31	0
2023	0	70	0	0	0	0	15	1	0	0	0	30	0
2024	0	67	0	0	0	0	13	1	0	0	0	30	0
2025	0	64	0	0	0	0	12	1	0	0	0	29	0
2026	0	61	0	0	0	0	11	0	0	0	0	28	0
2027	0	58	0	0	0	0	10	0	0	0	0	28	0
2028	0	56	0	0	0	0	9	0	0	0	0	27	0
2029	0	53	0	0	0	0	8	0	0	0	0	27	0
2030	0	51	0	0	0	0	7	0	0	0	0	26	0
SubT	0	1428	0	0	0	0	322	16	0	0	0	633	0
19yr	0	574	0	0	0	0	44	2	0	0	0	387	0
Total	0	2001	0	0	0	0	366	17	0	0	0	1020	0

		Capital											
Year	Oper Inc	CEE	CDE	CCA	COGPE	Total Capital	Net Rev	Cum Net Rev	ARTC	Aband Cost	SK Tax	Cash Flow	Cum Cash Flow
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	5	0	0	0	0	0	5	5	0	0	0	5	5
2012	19	0	0	0	0	0	19	25	0	0	0	19	25
2013	22	0	0	0	0	0	22	46	0	0	0	22	46
2014	27	0	0	0	0	0	27	73	0	0	0	27	73
2015	34	0	0	0	0	0	34	108	0	0	0	34	108
2016	33	0	0	0	0	0	33	141	0	0	0	33	141
2017	32	0	0	0	0	0	32	172	0	0	0	32	172
2018	30	0	0	0	0	0	30	203	0	0	0	30	203
2019	29	0	0	0	0	0	29	232	0	0	0	29	232
2020	28	0	0	0	0	0	28	260	0	0	0	28	260
2021	28	0	0	0	0	0	28	288	0	0	0	28	288
2022	27	0	0	0	0	0	27	315	0	0	0	27	315
2023	26	0	0	0	0	0	26	340	0	0	0	26	340
2024	25	0	0	0	0	0	25	365	0	0	0	25	365
2025	23	0	0	0	0	0	23	388	0	0	0	23	388
2026	22	0	0	0	0	0	22	410	0	0	0	22	410
2027	21	0	0	0	0	0	21	431	0	0	0	21	431
2028	20	0	0	0	0	0	20	452	0	0	0	20	452
2029	19	0	0	0	0	0	19	471	0	0	0	19	471
2030	18	0	0	0	0	0	18	489	0	0	0	18	489
SubT	489	0	0	0	0	0	489		0	0	0	489	
19yr	144	0	0	0	0	0	144		0	6	0	138	
Total	633	0	0	0	0	0	633		0	6	0	626	

	Discounted Cash Streams NPV (M$)						
discR%	5	10	12	15	18	20	25
BT Net	366	244	213	178	153	139	113
BT Cash Flow	365	243	213	178	152	139	113

Table 3

Proved Developed Producing

Eagleford Energy Inc.

Botha

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil	Heavy Oil	Solution Gas	Non-Assoc Assoc Gas	Ethane	Propane	Butane	Pentanes Plus	Total NGL	Sulphur	Equiv Oil
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MLt	Mboe
Gross	0.0	0.0	0	3901	0.0	0.0	0.0	0.0	0.0	0.0	650.1
Co Grs	0.0	0.0	0	203	0.0	0.0	0.0	0.0	0.0	0.0	33.8
Co Net	0.0	0.0	0	161	0.0	0.0	0.0	0.0	0.0	0.0	26.9

Net Present Value

Discount Rate	Total Net Capital	Before Tax Net Rev	ARTC Cap GCA	Aband Cost	SK Tax Overhead	Before Tax Cash Flow
%	M$	M$	M$	M$	M$	M$
0.0	0	449	0	5	0	444
5.0	0	290	0	1	0	288
8.0	0	233	0	1	0	233
10.0	0	205	0	0	0	205
12.0	0	182	0	0	0	182
15.0	0	155	0	0	0	155
20.0	0	124	0	0	0	124
25.0	0	102	0	0	0	102

Reserve Life = 30.2 yrs   Reserve Half Life = 7.1 yrs   BOE Reserve Index = 11.2

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs	Gas Comp Grs	BOE Comp Grs	Oil Rev	Gas Rev	Other Rev	Total Crown	Non-Crown	Lease Expen	Other Expen	Total Cap	Aband Etc	BTax Cash Flow
	bbl/d	Mcf/d	boe/d	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	51	8	0	23	0	4	0	14	0	0	0	5
2012	0	48	8	0	72	0	14	0	40	0	0	0	18
2013	0	44	7	0	73	0	15	0	38	0	0	0	20
2014	0	41	7	0	79	0	18	0	36	0	0	0	25
2015	0	37	6	0	90	0	23	0	35	0	0	0	32
2016	0	34	6	0	84	0	21	0	33	0	0	0	30
2017	0	32	5	0	79	0	19	0	32	0	0	0	28
2018	0	29	5	0	74	0	17	0	31	0	0	0	27
2019	0	27	4	0	70	0	15	0	30	0	0	0	26
2020	0	25	4	0	66	0	13	0	29	0	0	0	25
2021	0	23	4	0	62	0	11	0	28	0	0	0	23
2022	0	21	3	0	58	0	9	0	27	0	0	0	22
2023	0	19	3	0	54	0	8	0	26	0	0	0	20
2024	0	18	3	0	51	0	7	0	25	0	0	0	19
2025	0	16	3	0	48	0	6	0	24	0	0	0	18
2026	0	15	3	0	45	0	5	0	24	0	0	0	16
2027	0	14	2	0	42	0	4	0	23	0	0	0	15
2028	0	13	2	0	40	0	3	0	23	0	0	0	14
2029	0	12	2	0	37	0	3	0	22	0	0	0	12
2030	0	11	2	0	35	0	2	0	22	0	0	0	11
SubT				0	1184	0	217	0	561	0	0	0	406
11yr				0	216	0	11	0	162	0	0	5	38
Total				0	1400	0	228	0	722	0	0	5	444
Discounted	5%			0	885	0	162	0	433	0	0	1	288
Cash	10%			0	627	0	124	0	299	0	0	0	205
Streams	15%			0	481	0	99	0	227	0	0	0	155
	20%			0	389	0	81	0	184	0	0	0	124

Table 3

Proved Developed Producing

Eagleford Energy Inc.

Botha

Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	2	974	119	6	5	3.70
2012	2	922	337	18	13	4.09
2013	2	848	310	16	12	4.56
2014	2	780	285	15	11	5.36
2015	2	718	262	14	10	6.58
2016	2	661	242	13	9	6.72
2017	2	608	222	12	8	6.86
2018	2	560	204	11	8	7.01
2019	2	515	188	10	7	7.15
2020	2	474	174	9	7	7.30
2021	2	437	159	8	7	7.46
2022	2	402	147	8	6	7.61
2023	2	370	135	7	6	7.76
2024	2	341	125	6	5	7.91
2025	2	314	114	6	5	8.06
2026	2	289	105	5	5	8.22
2027	2	266	97	5	5	8.38
2028	2	245	90	5	4	8.55
2029	2	225	82	4	4	8.71
2030	2	208	76	4	4	8.89
SubT			3473	181	140	
11yr			428	22	21	
Total			3901	203	161	

Table 3

Proved Developed Producing

Eagleford Energy Inc.

Botha

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

	Revenue						Royalties						
Year	Oil	Gas	NGL	Sul	Roy	Other Income	Crown	Adjust	FH/ Indian	ORR	Min Taxes	Opex	NPI/ Other Expense
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	23	0	0	0	0	4	0	0	0	0	14	0
2012	0	72	0	0	0	0	15	1	0	0	0	40	0
2013	0	73	0	0	0	0	16	1	0	0	0	38	0
2014	0	79	0	0	0	0	19	1	0	0	0	36	0
2015	0	90	0	0	0	0	24	1	0	0	0	35	0
2016	0	84	0	0	0	0	22	1	0	0	0	33	0
2017	0	79	0	0	0	0	20	1	0	0	0	32	0
2018	0	74	0	0	0	0	17	1	0	0	0	31	0
2019	0	70	0	0	0	0	15	1	0	0	0	30	0
2020	0	66	0	0	0	0	13	1	0	0	0	29	0
2021	0	62	0	0	0	0	12	1	0	0	0	28	0
2022	0	58	0	0	0	0	10	0	0	0	0	27	0
2023	0	54	0	0	0	0	8	0	0	0	0	26	0
2024	0	51	0	0	0	0	7	0	0	0	0	25	0
2025	0	48	0	0	0	0	6	0	0	0	0	24	0
2026	0	45	0	0	0	0	5	0	0	0	0	24	0
2027	0	42	0	0	0	0	4	0	0	0	0	23	0
2028	0	40	0	0	0	0	4	0	0	0	0	23	0
2029	0	37	0	0	0	0	3	0	0	0	0	22	0
2030	0	35	0	0	0	0	3	0	0	0	0	22	0
SubT	0	1184	0	0	0	0	229	11	0	0	0	561	0
11yr	0	216	0	0	0	0	12	1	0	0	0	162	0
Total	0	1400	0	0	0	0	240	12	0	0	0	722	0

		Capital											
Year	Oper Inc	CEE	CDE	CCA	COGPE	Total Capital	Net Rev	Cum Net Rev	ARTC	Aband Cost	SK Tax	Cash Flow	Cum Cash Flow
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	5	0	0	0	0	0	5	5	0	0	0	5	5
2012	18	0	0	0	0	0	18	24	0	0	0	18	24
2013	20	0	0	0	0	0	20	44	0	0	0	20	44
2014	25	0	0	0	0	0	25	69	0	0	0	25	69
2015	32	0	0	0	0	0	32	100	0	0	0	32	100
2016	30	0	0	0	0	0	30	130	0	0	0	30	130
2017	28	0	0	0	0	0	28	159	0	0	0	28	159
2018	27	0	0	0	0	0	27	186	0	0	0	27	186
2019	26	0	0	0	0	0	26	211	0	0	0	26	211
2020	25	0	0	0	0	0	25	236	0	0	0	25	236
2021	23	0	0	0	0	0	23	259	0	0	0	23	259
2022	22	0	0	0	0	0	22	281	0	0	0	22	281
2023	20	0	0	0	0	0	20	301	0	0	0	20	301
2024	19	0	0	0	0	0	19	320	0	0	0	19	320
2025	18	0	0	0	0	0	18	338	0	0	0	18	338
2026	16	0	0	0	0	0	16	354	0	0	0	16	354
2027	15	0	0	0	0	0	15	369	0	0	0	15	369
2028	14	0	0	0	0	0	14	383	0	0	0	14	383
2029	12	0	0	0	0	0	12	395	0	0	0	12	395
2030	11	0	0	0	0	0	11	406	0	0	0	11	406
SubT	406	0	0	0	0	0	406		0	0	0	406	
11yr	44	0	0	0	0	0	44		0	5	0	38	
Total	449	0	0	0	0	0	449		0	5	0	444	

	Discounted Cash Streams NPV (M$)						
discR%	5	10	12	15	18	20	25
BT Net	290	205	182	155	135	124	102
BT Cash Flow	288	205	182	155	135	124	102

Table 3

Probable

Eagleford Energy Inc.

Botha

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil	Heavy Oil	Solution Gas	Non-Assoc Assoc Gas	Ethane	Propane	Butane	Pentanes Plus	Total NGL	Sulphur	Equiv Oil
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MLt	Mboe
Gross	0.0	0.0	0	1276	0.0	0.0	0.0	0.0	0.0	0.0	212.7
Co Grs	0.0	0.0	0	66	0.0	0.0	0.0	0.0	0.0	0.0	11.1
Co Net	0.0	0.0	0	49	0.0	0.0	0.0	0.0	0.0	0.0	8.2

Net Present Value

Discount Rate	Total Net Capital	Before Tax Net Rev	ARTC Cap GCA	Aband Cost	SK Tax Overhead	Before Tax Cash Flow
%	M$	M$	M$	M$	M$	M$
0.0	0	183	0	1	0	182
5.0	0	76	0	0	0	77
8.0	0	50	0	0	0	50
10.0	0	39	0	0	0	39
12.0	0	31	0	0	0	31
15.0	0	23	0	0	0	23
20.0	0	15	0	0	0	15
25.0	0	11	0	0	0	11

Reserve Life = 38.2 yrs   Reserve Half Life = 19.4 yrs   BOE Reserve Index = 90.4

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs	Gas Comp Grs	BOE Comp Grs	Oil Rev	Gas Rev	Other Rev	Total Crown	Non-Crown	Lease Expen	Other Expen	Total Cap	Aband Etc	BTax Cash Flow
	bbl/d	Mcf/d	boe/d	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	2	0	0	1	0	0	0	0	0	0	0	0
2012	0	2	0	0	3	0	1	0	1	0	0	0	1
2013	0	3	0	0	5	0	1	0	2	0	0	0	1
2014	0	4	1	0	7	0	2	0	2	0	0	0	2
2015	0	4	1	0	10	0	4	0	3	0	0	0	3
2016	0	4	1	0	11	0	5	0	3	0	0	0	3
2017	0	5	1	0	12	0	5	0	3	0	0	0	3
2018	0	5	1	0	13	0	5	0	4	0	0	0	4
2019	0	5	1	0	13	0	6	0	4	0	0	0	4
2020	0	5	1	0	14	0	6	0	4	0	0	0	4
2021	0	5	1	0	15	0	6	0	4	0	0	0	4
2022	0	5	1	0	15	0	6	0	4	0	0	0	5
2023	0	5	1	0	15	0	6	0	4	0	0	0	5
2024	0	5	1	0	16	0	6	0	5	0	0	0	5
2025	0	5	1	0	16	0	6	0	5	0	0	0	6
2026	0	5	1	0	16	0	5	0	5	0	0	0	6
2027	0	5	1	0	16	0	5	0	5	0	0	0	6
2028	0	5	1	0	16	0	5	0	5	0	0	0	7
2029	0	5	1	0	16	0	5	0	5	0	0	0	7
2030	0	5	1	0	16	0	4	0	5	0	0	0	7
SubT				0	244	0	89	0	72	0	0	0	83
19yr				0	357	0	31	0	226	0	0	1	99
Total				0	601	0	120	0	298	0	0	1	182
Discounted	5%			0	236	0	63	0	97	0	0	0	77
Cash	10%			0	120	0	38	0	43	0	0	0	39
Streams	15%			0	73	0	26	0	24	0	0	0	23
	20%			0	50	0	18	0	16	0	0	0	15

Sproule

Table 3

Probable

Eagleford Energy Inc.

Botha

Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	0	34	4	0	0	3.70
2012	0	43	16	1	1	4.09
2013	0	57	21	1	1	4.56
2014	0	68	25	1	1	5.36
2015	0	77	28	1	1	6.58
2016	0	84	31	2	1	6.72
2017	0	90	33	2	1	6.86
2018	0	95	35	2	1	7.01
2019	0	98	36	2	1	7.15
2020	0	101	37	2	1	7.30
2021	0	103	38	2	1	7.46
2022	0	104	38	2	1	7.61
2023	0	104	38	2	1	7.76
2024	0	104	38	2	1	7.91
2025	0	103	38	2	1	8.06
2026	0	102	37	2	1	8.22
2027	0	101	37	2	1	8.38
2028	0	99	36	2	1	8.55
2029	0	97	35	2	1	8.71
2030	0	94	34	2	1	8.89
SubT			633	33	19	
19yr			643	33	30	
Total			1276	66	49	

Table 3

Probable

Eagleford Energy Inc.

Botha

Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Revenue: Oil M$	Revenue: Gas M$	Revenue: NGL M$	Revenue: Sul M$	Revenue: Roy M$	Revenue: Other Income M$	Royalties: Crown M$	Royalties: Adjust M$	Royalties: FH/ Indian M$	Royalties: ORR M$	Royalties: Min Taxes M$	Opex M$	NPI/ Other Expense M$
2011	0	1	0	0	0	0	0	0	0	0	0	0	0
2012	0	3	0	0	0	0	1	0	0	0	0	1	0
2013	0	5	0	0	0	0	2	0	0	0	0	2	0
2014	0	7	0	0	0	0	2	0	0	0	0	2	0
2015	0	10	0	0	0	0	4	0	0	0	0	3	0
2016	0	11	0	0	0	0	5	0	0	0	0	3	0
2017	0	12	0	0	0	0	5	0	0	0	0	3	0
2018	0	13	0	0	0	0	6	0	0	0	0	4	0
2019	0	13	0	0	0	0	6	0	0	0	0	4	0
2020	0	14	0	0	0	0	6	0	0	0	0	4	0
2021	0	15	0	0	0	0	6	0	0	0	0	4	0
2022	0	15	0	0	0	0	6	0	0	0	0	4	0
2023	0	15	0	0	0	0	6	0	0	0	0	4	0
2024	0	16	0	0	0	0	6	0	0	0	0	5	0
2025	0	16	0	0	0	0	6	0	0	0	0	5	0
2026	0	16	0	0	0	0	6	0	0	0	0	5	0
2027	0	16	0	0	0	0	5	0	0	0	0	5	0
2028	0	16	0	0	0	0	5	0	0	0	0	5	0
2029	0	16	0	0	0	0	5	0	0	0	0	5	0
2030	0	16	0	0	0	0	4	0	0	0	0	5	0
SubT	0	244	0	0	0	0	93	4	0	0	0	72	0
19yr	0	357	0	0	0	0	32	1	0	0	0	226	0
Total	0	601	0	0	0	0	126	6	0	0	0	298	0

Year	Oper Inc M$	Capital: CEE M$	Capital: CDE M$	Capital: CCA M$	Capital: COGPE M$	Total Capital M$	Net Rev M$	Cum Net Rev M$	ARTC M$	Aband Cost M$	SK Tax M$	Cash Flow M$	Cum Cash Flow M$
2011	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	1	0	0	0	0	0	1	1	0	0	0	1	1
2013	1	0	0	0	0	0	1	3	0	0	0	1	3
2014	2	0	0	0	0	0	2	5	0	0	0	2	5
2015	3	0	0	0	0	0	3	8	0	0	0	3	8
2016	3	0	0	0	0	0	3	10	0	0	0	3	10
2017	3	0	0	0	0	0	3	14	0	0	0	3	14
2018	4	0	0	0	0	0	4	17	0	0	0	4	17
2019	4	0	0	0	0	0	4	21	0	0	0	4	21
2020	4	0	0	0	0	0	4	25	0	0	0	4	25
2021	4	0	0	0	0	0	4	29	0	0	0	4	29
2022	5	0	0	0	0	0	5	34	0	0	0	5	34
2023	5	0	0	0	0	0	5	39	0	0	0	5	39
2024	5	0	0	0	0	0	5	44	0	0	0	5	44
2025	6	0	0	0	0	0	6	50	0	0	0	6	50
2026	6	0	0	0	0	0	6	56	0	0	0	6	56
2027	6	0	0	0	0	0	6	62	0	0	0	6	62
2028	7	0	0	0	0	0	7	69	0	0	0	7	69
2029	7	0	0	0	0	0	7	76	0	0	0	7	76
2030	7	0	0	0	0	0	7	83	0	0	0	7	83
SubT	83	0	0	0	0	0	83		0	0	0	83	
19yr	100	0	0	0	0	0	100		0	1	0	99	
Total	183	0	0	0	0	0	183		0	1	0	182	

Discounted Cash Streams NPV (M$)

discR%	5	10	12	15	18	20	25
BT Net	76	39	31	23	18	15	11
BT Cash Flow	77	39	31	23	18	15	11

Table 3

Proved Developed Producing

Eagleford Energy Inc.

Botha

100/06-14-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil Mbbl	Heavy Oil Mbbl	Solution Gas MMcf	Non-Assoc Assoc Gas MMcf	Ethane Mbbl	Propane Mbbl	Butane Mbbl	Pentanes Plus Mbbl	Total NGL Mbbl	Sulphur MLt	Equiv Oil Mboe
Gross	0.0	0.0	0	2316	0.0	0.0	0.0	0.0	0.0	0.0	386.0
Co Grs	0.0	0.0	0	120	0.0	0.0	0.0	0.0	0.0	0.0	20.1
Co Net	0.0	0.0	0	94	0.0	0.0	0.0	0.0	0.0	0.0	15.7

Net Present Value

Discount Rate %	Total Net Capital M$	Before Tax Net Rev M$	ARTC Cap GCA M$	Aband Cost M$	SK Tax Overhead M$	Before Tax Cash Flow M$
0.0	0	272	0	3	0	269
5.0	0	169	0	1	0	169
8.0	0	135	0	0	0	134
10.0	0	118	0	0	0	117
12.0	0	104	0	0	0	104
15.0	0	88	0	0	0	88
20.0	0	70	0	0	0	70
25.0	0	57	0	0	0	57

Reserve Life = 30.2 yrs   Reserve Half Life = 7.7 yrs   BOE Reserve Index = 12.1

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs bbl/d	Gas Comp Grs Mcf/d	BOE Comp Grs boe/d	Oil Rev M$	Gas Rev M$	Other Rev M$	Total Crown M$	Non-Crown M$	Lease Expen M$	Other Expen M$	Total Cap M$	Aband Etc M$	BTax Cash Flow M$
2011	0	28	5	0	13	0	2	0	7	0	0	0	3
2012	0	27	4	0	40	0	8	0	22	0	0	0	10
2013	0	25	4	0	41	0	9	0	21	0	0	0	11
2014	0	23	4	0	44	0	11	0	20	0	0	0	14
2015	0	21	4	0	50	0	14	0	19	0	0	0	18
2016	0	19	3	0	48	0	13	0	18	0	0	0	17
2017	0	18	3	0	45	0	12	0	18	0	0	0	16
2018	0	17	3	0	43	0	11	0	17	0	0	0	15
2019	0	15	3	0	40	0	10	0	16	0	0	0	14
2020	0	14	2	0	38	0	8	0	16	0	0	0	14
2021	0	13	2	0	36	0	7	0	15	0	0	0	13
2022	0	12	2	0	34	0	6	0	15	0	0	0	13
2023	0	11	2	0	32	0	6	0	14	0	0	0	12
2024	0	10	2	0	30	0	5	0	14	0	0	0	11
2025	0	10	2	0	28	0	4	0	14	0	0	0	10
2026	0	9	1	0	27	0	4	0	13	0	0	0	10
2027	0	8	1	0	25	0	3	0	13	0	0	0	9
2028	0	8	1	0	24	0	3	0	13	0	0	0	9
2029	0	7	1	0	23	0	2	0	12	0	0	0	8
2030	0	7	1	0	21	0	2	0	12	0	0	0	7
SubT				0	683	0	140	0	308	0	0	0	234
11yr				0	166	0	9	0	120	0	0	3	35
Total				0	849	0	149	0	428	0	0	3	269
Discounted	5%			0	519	0	103	0	246	0	0	1	169
Cash	10%			0	361	0	77	0	166	0	0	0	117
Streams	15%			0	274	0	61	0	125	0	0	0	88
	20%			0	220	0	50	0	101	0	0	0	70

Table 3

Proved Developed Producing

Eagleford Energy Inc.

Botha

100/06-14-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	1	538	66	3	3	3.70
2012	1	511	187	10	7	4.09
2013	1	472	172	9	7	4.56
2014	1	437	160	8	6	5.36
2015	1	405	148	8	5	6.58
2016	1	374	137	7	5	6.72
2017	1	346	126	7	5	6.86
2018	1	320	117	6	4	7.01
2019	1	297	108	6	4	7.15
2020	1	274	100	5	4	7.30
2021	1	254	93	5	4	7.46
2022	1	235	86	4	3	7.61
2023	1	217	79	4	3	7.76
2024	1	201	74	4	3	7.91
2025	1	186	68	4	3	8.06
2026	1	172	63	3	3	8.22
2027	1	159	58	3	3	8.38
2028	1	147	54	3	2	8.55
2029	1	136	50	3	2	8.71
2030	1	126	46	2	2	8.89
SubT			1991	103	78	
11yr			325	17	16	
Total			2316	120	94	

Table 3

Proved Developed Producing

Eagleford Energy Inc.

Botha

100/06-14-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Revenue: Oil	Revenue: Gas	Revenue: NGL	Revenue: Sul	Revenue: Roy	Revenue: Other Income	Royalties: Crown	Royalties: Adjust	Royalties: FH/ Indian	Royalties: ORR	Royalties: Min Taxes	Opex	NPI/ Other Expense
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	13	0	0	0	0	2	0	0	0	0	7	0
2012	0	40	0	0	0	0	9	1	0	0	0	22	0
2013	0	41	0	0	0	0	10	1	0	0	0	21	0
2014	0	44	0	0	0	0	11	1	0	0	0	20	0
2015	0	50	0	0	0	0	15	1	0	0	0	19	0
2016	0	48	0	0	0	0	14	1	0	0	0	18	0
2017	0	45	0	0	0	0	13	1	0	0	0	18	0
2018	0	43	0	0	0	0	11	1	0	0	0	17	0
2019	0	40	0	0	0	0	10	0	0	0	0	16	0
2020	0	38	0	0	0	0	9	0	0	0	0	16	0
2021	0	36	0	0	0	0	8	0	0	0	0	15	0
2022	0	34	0	0	0	0	7	0	0	0	0	15	0
2023	0	32	0	0	0	0	6	0	0	0	0	14	0
2024	0	30	0	0	0	0	5	0	0	0	0	14	0
2025	0	28	0	0	0	0	5	0	0	0	0	14	0
2026	0	27	0	0	0	0	4	0	0	0	0	13	0
2027	0	25	0	0	0	0	3	0	0	0	0	13	0
2028	0	24	0	0	0	0	3	0	0	0	0	13	0
2029	0	23	0	0	0	0	2	0	0	0	0	12	0
2030	0	21	0	0	0	0	2	0	0	0	0	12	0
SubT	0	683	0	0	0	0	148	7	0	0	0	308	0
11yr	0	166	0	0	0	0	9	0	0	0	0	120	0
Total	0	849	0	0	0	0	157	8	0	0	0	428	0

Year	Oper Inc	Capital: CEE	Capital: CDE	Capital: CCA	Capital: COGPE	Capital: Total Capital	Net Rev	Cum Net Rev	ARTC	Aband Cost	SK Tax	Cash Flow	Cum Cash Flow
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	3	0	0	0	0	0	3	3	0	0	0	3	3
2012	10	0	0	0	0	0	10	13	0	0	0	10	13
2013	11	0	0	0	0	0	11	25	0	0	0	11	25
2014	14	0	0	0	0	0	14	38	0	0	0	14	38
2015	18	0	0	0	0	0	18	56	0	0	0	18	56
2016	17	0	0	0	0	0	17	72	0	0	0	17	72
2017	16	0	0	0	0	0	16	88	0	0	0	16	88
2018	15	0	0	0	0	0	15	103	0	0	0	15	103
2019	14	0	0	0	0	0	14	117	0	0	0	14	117
2020	14	0	0	0	0	0	14	131	0	0	0	14	131
2021	13	0	0	0	0	0	13	144	0	0	0	13	144
2022	13	0	0	0	0	0	13	157	0	0	0	13	157
2023	12	0	0	0	0	0	12	169	0	0	0	12	169
2024	11	0	0	0	0	0	11	180	0	0	0	11	180
2025	10	0	0	0	0	0	10	191	0	0	0	10	191
2026	10	0	0	0	0	0	10	201	0	0	0	10	201
2027	9	0	0	0	0	0	9	210	0	0	0	9	210
2028	9	0	0	0	0	0	9	219	0	0	0	9	219
2029	8	0	0	0	0	0	8	227	0	0	0	8	227
2030	7	0	0	0	0	0	7	234	0	0	0	7	234
SubT	234	0	0	0	0	0	234		0	0	0	234	
11yr	38	0	0	0	0	0	38		0	3	0	35	
Total	272	0	0	0	0	0	272		0	3	0	269	

Discounted Cash Streams NPV (M$)

discR%	5	10	12	15	18	20	25
BT Net	169	118	104	88	76	70	57
BT Cash Flow	169	117	104	88	76	70	57

Sproule

Table 3

Proved+Probable Developed Producing

Eagleford Energy Inc.

Botha

100/06-14-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil	Heavy Oil	Solution Gas	Non-Assoc Assoc Gas	Ethane	Propane	Butane	Pentanes Plus	Total NGL	Sulphur	Equiv Oil
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MLt	Mboe
Gross	0.0	0.0	0	2943	0.0	0.0	0.0	0.0	0.0	0.0	490.5
Co Grs	0.0	0.0	0	153	0.0	0.0	0.0	0.0	0.0	0.0	25.5
Co Net	0.0	0.0	0	118	0.0	0.0	0.0	0.0	0.0	0.0	19.7

Net Present Value

Discount Rate	Total Net Capital	Before Tax Net Rev	ARTC Cap GCA	Aband Cost	SK Tax Overhead	Before Tax Cash Flow
%	M$	M$	M$	M$	M$	M$
0.0	0	365	0	3	0	361
5.0	0	204	0	1	0	204
8.0	0	156	0	0	0	156
10.0	0	134	0	0	0	134
12.0	0	116	0	0	0	116
15.0	0	97	0	0	0	97
20.0	0	75	0	0	0	75
25.0	0	61	0	0	0	61

Reserve Life = 38.2 yrs   Reserve Half Life = 9.8 yrs   BOE Reserve Index = 15.2

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs	Gas Comp Grs	BOE Comp Grs	Oil Rev	Gas Rev	Other Rev	Total Crown	Non-Crown	Lease Expen	Other Expen	Total Cap	Aband Etc	BTax Cash Flow
	bbl/d	Mcf/d	boe/d	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	28	5	0	13	0	2	0	7	0	0	0	3
2012	0	27	4	0	40	0	8	0	22	0	0	0	10
2013	0	25	4	0	42	0	9	0	21	0	0	0	12
2014	0	24	4	0	47	0	12	0	21	0	0	0	14
2015	0	22	4	0	54	0	15	0	20	0	0	0	19
2016	0	21	4	0	52	0	15	0	19	0	0	0	18
2017	0	20	3	0	50	0	14	0	19	0	0	0	17
2018	0	19	3	0	48	0	13	0	18	0	0	0	16
2019	0	18	3	0	46	0	12	0	18	0	0	0	16
2020	0	17	3	0	44	0	11	0	18	0	0	0	15
2021	0	16	3	0	42	0	10	0	17	0	0	0	15
2022	0	15	2	0	41	0	9	0	17	0	0	0	14
2023	0	14	2	0	39	0	9	0	16	0	0	0	14
2024	0	13	2	0	37	0	8	0	16	0	0	0	14
2025	0	12	2	0	36	0	7	0	16	0	0	0	13
2026	0	11	2	0	34	0	7	0	15	0	0	0	12
2027	0	11	2	0	33	0	6	0	15	0	0	0	12
2028	0	10	2	0	32	0	6	0	15	0	0	0	11
2029	0	10	2	0	30	0	5	0	15	0	0	0	11
2030	0	9	1	0	29	0	5	0	14	0	0	0	10
SubT				0	788	0	182	0	339	0	0	0	267
19yr				0	373	0	31	0	244	0	0	3	95
Total				0	1161	0	213	0	583	0	0	3	361
Discounted Cash Streams	5%			0	628	0	134	0	290	0	0	1	204
	10%			0	412	0	95	0	184	0	0	0	134
	15%			0	303	0	72	0	134	0	0	0	97
	20%			0	239	0	57	0	107	0	0	0	75

Sproule

Table 3

Proved+Probable Developed Producing

Eagleford Energy Inc.

Botha

100/06-14-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	1	540	66	3	3	3.70
2012	1	518	190	10	7	4.09
2013	1	488	178	9	7	4.56
2014	1	459	167	9	6	5.36
2015	1	431	157	8	6	6.58
2016	1	406	149	8	5	6.72
2017	1	382	139	7	5	6.86
2018	1	359	131	7	5	7.01
2019	1	338	123	6	4	7.15
2020	1	318	116	6	4	7.30
2021	1	299	109	6	4	7.46
2022	1	281	103	5	4	7.61
2023	1	265	97	5	4	7.76
2024	1	249	91	5	4	7.91
2025	1	234	85	4	3	8.06
2026	1	220	80	4	3	8.22
2027	1	207	76	4	3	8.38
2028	1	195	71	4	3	8.55
2029	1	183	67	3	3	8.71
2030	1	172	63	3	3	8.89
SubT			2259	117	86	
19yr			684	36	32	
Total			2943	153	118	

Table 3

Proved+Probable Developed Producing

Eagleford Energy Inc.

Botha

100/06-14-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil M$	Gas M$	NGL M$	Sul M$	Roy M$	Other Income M$	Crown M$	Adjust M$	FH/ Indian M$	ORR M$	Min Taxes M$	Opex M$	NPI/ Other Expense M$
	Revenue						Royalties						
2011	0	13	0	0	0	0	2	0	0	0	0	7	0
2012	0	40	0	0	0	0	9	1	0	0	0	22	0
2013	0	42	0	0	0	0	10	1	0	0	0	21	0
2014	0	47	0	0	0	0	12	1	0	0	0	21	0
2015	0	54	0	0	0	0	16	1	0	0	0	20	0
2016	0	52	0	0	0	0	15	1	0	0	0	19	0
2017	0	50	0	0	0	0	14	1	0	0	0	19	0
2018	0	48	0	0	0	0	14	1	0	0	0	18	0
2019	0	46	0	0	0	0	13	1	0	0	0	18	0
2020	0	44	0	0	0	0	12	1	0	0	0	18	0
2021	0	42	0	0	0	0	11	0	0	0	0	17	0
2022	0	41	0	0	0	0	10	0	0	0	0	17	0
2023	0	39	0	0	0	0	9	0	0	0	0	16	0
2024	0	37	0	0	0	0	8	0	0	0	0	16	0
2025	0	36	0	0	0	0	7	0	0	0	0	16	0
2026	0	34	0	0	0	0	7	0	0	0	0	15	0
2027	0	33	0	0	0	0	6	0	0	0	0	15	0
2028	0	32	0	0	0	0	6	0	0	0	0	15	0
2029	0	30	0	0	0	0	5	0	0	0	0	15	0
2030	0	29	0	0	0	0	5	0	0	0	0	14	0
SubT	0	788	0	0	0	0	192	9	0	0	0	339	0
19yr	0	373	0	0	0	0	32	1	0	0	0	244	0
Total	0	1161	0	0	0	0	224	11	0	0	0	583	0

Year	Oper Inc M$	CEE M$	CDE M$	CCA M$	COGPE M$	Total Capital M$	Net Rev M$	Cum Net Rev M$	ARTC M$	Aband Cost M$	SK Tax M$	Cash Flow M$	Cum Cash Flow M$
		Capital											
2011	3	0	0	0	0	0	3	3	0	0	0	3	3
2012	10	0	0	0	0	0	10	13	0	0	0	10	13
2013	12	0	0	0	0	0	12	25	0	0	0	12	25
2014	14	0	0	0	0	0	14	40	0	0	0	14	40
2015	19	0	0	0	0	0	19	58	0	0	0	19	58
2016	18	0	0	0	0	0	18	76	0	0	0	18	76
2017	17	0	0	0	0	0	17	93	0	0	0	17	93
2018	16	0	0	0	0	0	16	109	0	0	0	16	109
2019	16	0	0	0	0	0	16	125	0	0	0	16	125
2020	15	0	0	0	0	0	15	140	0	0	0	15	140
2021	15	0	0	0	0	0	15	155	0	0	0	15	155
2022	14	0	0	0	0	0	14	169	0	0	0	14	169
2023	14	0	0	0	0	0	14	184	0	0	0	14	184
2024	14	0	0	0	0	0	14	197	0	0	0	14	197
2025	13	0	0	0	0	0	13	210	0	0	0	13	210
2026	12	0	0	0	0	0	12	223	0	0	0	12	223
2027	12	0	0	0	0	0	12	235	0	0	0	12	235
2028	11	0	0	0	0	0	11	246	0	0	0	11	246
2029	11	0	0	0	0	0	11	257	0	0	0	11	257
2030	10	0	0	0	0	0	10	267	0	0	0	10	267
SubT	267	0	0	0	0	0	267		0	0	0	267	
19yr	98	0	0	0	0	0	98		0	3	0	95	
Total	365	0	0	0	0	0	365		0	3	0	361	

Discounted Cash Streams NPV (M$)

discR%	5	10	12	15	18	20	25
BT Net	204	134	116	97	83	75	61
BT Cash Flow	204	134	116	97	83	75	61

Sproule

Table 3

Proved Developed Producing

Eagleford Energy Inc.

Botha

102/06-22-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil	Heavy Oil	Solution Gas	Non-Assoc Assoc Gas	Ethane	Propane	Butane	Pentanes Plus	Total NGL	Sulphur	Equiv Oil
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MLt	Mboe
Gross	0.0	0.0	0	1585	0.0	0.0	0.0	0.0	0.0	0.0	264.2
Co Grs	0.0	0.0	0	82	0.0	0.0	0.0	0.0	0.0	0.0	13.7
Co Net	0.0	0.0	0	67	0.0	0.0	0.0	0.0	0.0	0.0	11.2

Net Present Value

Discount Rate	Total Net Capital	Before Tax Net Rev	ARTC Cap GCA	Aband Cost	SK Tax Overhead	Before Tax Cash Flow
%	M$	M$	M$	M$	M$	M$
0.0	0	178	0	3	0	175
5.0	0	120	0	1	0	119
8.0	0	99	0	0	0	98
10.0	0	88	0	0	0	87
12.0	0	78	0	0	0	78
15.0	0	67	0	0	0	67
20.0	0	54	0	0	0	54
25.0	0	45	0	0	0	45

Reserve Life = 23.8 yrs Reserve Half Life = 6.4 yrs BOE Reserve Index = 10.2

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs	Gas Comp Grs	BOE Comp Grs	Oil Rev	Gas Rev	Other Rev	Total Crown	Non-Crown	Lease Expen	Other Expen	Total Cap	Aband Etc	BTax Cash Flow
	bbl/d	Mcf/d	boe/d	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	23	4	0	10	0	2	0	6	0	0	0	2
2012	0	21	4	0	32	0	6	0	18	0	0	0	8
2013	0	20	3	0	32	0	6	0	17	0	0	0	9
2014	0	18	3	0	35	0	8	0	16	0	0	0	11
2015	0	16	3	0	39	0	9	0	16	0	0	0	14
2016	0	15	2	0	37	0	8	0	15	0	0	0	14
2017	0	14	2	0	34	0	7	0	14	0	0	0	13
2018	0	12	2	0	32	0	6	0	14	0	0	0	12
2019	0	11	2	0	30	0	5	0	13	0	0	0	11
2020	0	10	2	0	28	0	4	0	13	0	0	0	11
2021	0	10	2	0	26	0	4	0	12	0	0	0	10
2022	0	9	1	0	24	0	3	0	12	0	0	0	9
2023	0	8	1	0	22	0	2	0	12	0	0	0	9
2024	0	7	1	0	21	0	2	0	11	0	0	0	8
2025	0	7	1	0	19	0	1	0	11	0	0	0	7
2026	0	6	1	0	18	0	1	0	11	0	0	0	6
2027	0	6	1	0	17	0	1	0	10	0	0	0	6
2028	0	5	1	0	16	0	1	0	10	0	0	0	5
2029	0	5	1	0	15	0	1	0	10	0	0	0	4
2030	0	4	1	0	14	0	1	0	10	0	0	0	3
SubT				0	501	0	77	0	253	0	0	0	172
5yr				0	50	0	2	0	42	0	0	3	4
Total				0	551	0	79	0	294	0	0	3	175
Discounted	5%			0	366	0	59	0	187	0	0	1	119
Cash	10%			0	266	0	46	0	133	0	0	0	87
Streams	15%			0	207	0	38	0	102	0	0	0	67
	20%			0	169	0	32	0	83	0	0	0	54

Sproule

Table 3

Proved Developed Producing

Eagleford Energy Inc.

Botha

102/06-22-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	1	436	53	3	2	3.70
2012	1	411	150	8	6	4.09
2013	1	376	137	7	5	4.56
2014	1	343	125	7	5	5.36
2015	1	314	115	6	4	6.58
2016	1	287	105	5	4	6.72
2017	1	262	96	5	4	6.86
2018	1	239	87	5	4	7.01
2019	1	219	80	4	3	7.15
2020	1	200	73	4	3	7.30
2021	1	183	67	3	3	7.46
2022	1	167	61	3	3	7.61
2023	1	153	56	3	3	7.76
2024	1	140	51	3	2	7.91
2025	1	128	47	2	2	8.06
2026	1	117	43	2	2	8.22
2027	1	107	39	2	2	8.38
2028	1	97	36	2	2	8.55
2029	1	89	32	2	2	8.71
2030	1	81	30	2	1	8.89
SubT			1482	77	62	
5yr			103	5	5	
Total			1585	82	67	

Table 3

Proved Developed Producing

Eagleford Energy Inc.

Botha

102/06-22-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Revenue: Oil M$	Revenue: Gas M$	Revenue: NGL M$	Revenue: Sul M$	Revenue: Roy M$	Revenue: Other Income M$	Royalties: Crown M$	Royalties: Adjust M$	Royalties: FH/ Indian M$	Royalties: ORR M$	Royalties: Min Taxes M$	Opex M$	NPI/ Other Expense M$
2011	0	10	0	0	0	0	2	0	0	0	0	6	0
2012	0	32	0	0	0	0	6	0	0	0	0	18	0
2013	0	32	0	0	0	0	7	0	0	0	0	17	0
2014	0	35	0	0	0	0	8	0	0	0	0	16	0
2015	0	39	0	0	0	0	10	0	0	0	0	16	0
2016	0	37	0	0	0	0	8	0	0	0	0	15	0
2017	0	34	0	0	0	0	7	0	0	0	0	14	0
2018	0	32	0	0	0	0	6	0	0	0	0	14	0
2019	0	30	0	0	0	0	5	0	0	0	0	13	0
2020	0	28	0	0	0	0	5	0	0	0	0	13	0
2021	0	26	0	0	0	0	4	0	0	0	0	12	0
2022	0	24	0	0	0	0	3	0	0	0	0	12	0
2023	0	22	0	0	0	0	2	0	0	0	0	12	0
2024	0	21	0	0	0	0	2	0	0	0	0	11	0
2025	0	19	0	0	0	0	2	0	0	0	0	11	0
2026	0	18	0	0	0	0	1	0	0	0	0	11	0
2027	0	17	0	0	0	0	1	0	0	0	0	10	0
2028	0	16	0	0	0	0	1	0	0	0	0	10	0
2029	0	15	0	0	0	0	1	0	0	0	0	10	0
2030	0	14	0	0	0	0	1	0	0	0	0	10	0
SubT	0	501	0	0	0	0	81	4	0	0	0	253	0
5yr	0	50	0	0	0	0	2	0	0	0	0	42	0
Total	0	551	0	0	0	0	83	4	0	0	0	294	0

Year	Oper Inc M$	Capital: CEE M$	Capital: CDE M$	Capital: CCA M$	Capital: COGPE M$	Total Capital M$	Net Rev M$	Cum Net Rev M$	ARTC M$	Aband Cost M$	SK Tax M$	Cash Flow M$	Cum Cash Flow M$
2011	2	0	0	0	0	0	2	2	0	0	0	2	2
2012	8	0	0	0	0	0	8	10	0	0	0	8	10
2013	9	0	0	0	0	0	9	19	0	0	0	9	19
2014	11	0	0	0	0	0	11	30	0	0	0	11	30
2015	14	0	0	0	0	0	14	44	0	0	0	14	44
2016	14	0	0	0	0	0	14	58	0	0	0	14	58
2017	13	0	0	0	0	0	13	71	0	0	0	13	71
2018	12	0	0	0	0	0	12	83	0	0	0	12	83
2019	11	0	0	0	0	0	11	94	0	0	0	11	94
2020	11	0	0	0	0	0	11	105	0	0	0	11	105
2021	10	0	0	0	0	0	10	115	0	0	0	10	115
2022	9	0	0	0	0	0	9	124	0	0	0	9	124
2023	9	0	0	0	0	0	9	132	0	0	0	9	132
2024	8	0	0	0	0	0	8	140	0	0	0	8	140
2025	7	0	0	0	0	0	7	147	0	0	0	7	147
2026	6	0	0	0	0	0	6	154	0	0	0	6	154
2027	6	0	0	0	0	0	6	159	0	0	0	6	159
2028	5	0	0	0	0	0	5	164	0	0	0	5	164
2029	4	0	0	0	0	0	4	168	0	0	0	4	168
2030	3	0	0	0	0	0	3	172	0	0	0	3	172
SubT	172	0	0	0	0	0	172		0	0	0	172	
5yr	6	0	0	0	0	0	6		0	3	0	4	
Total	178	0	0	0	0	0	178		0	3	0	175	

Discounted Cash Streams NPV (M$)

discR%	5	10	12	15	18	20	25
BT Net	120	88	78	67	59	54	45
BT Cash Flow	119	87	78	67	59	54	45

Sproule

Table 3

Proved+Probable Developed Producing

Eagleford Energy Inc.

Botha

102/06-22-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Reserves

	LtMed Oil	Heavy Oil	Solution Gas	Non-Assoc Assoc Gas	Ethane	Propane	Butane	Pentanes Plus	Total NGL	Sulphur	Equiv Oil
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MLt	Mboe
Gross	0.0	0.0	0	2234	0.0	0.0	0.0	0.0	0.0	0.0	372.3
Co Grs	0.0	0.0	0	116	0.0	0.0	0.0	0.0	0.0	0.0	19.4
Co Net	0.0	0.0	0	93	0.0	0.0	0.0	0.0	0.0	0.0	15.4

Net Present Value

Discount Rate	Total Net Capital	Before Tax Net Rev	ARTC Cap GCA	Aband Cost	SK Tax Overhead	Before Tax Cash Flow
%	M$	M$	M$	M$	M$	M$
0.0	0	268	0	3	0	265
5.0	0	162	0	1	0	161
8.0	0	127	0	0	0	127
10.0	0	110	0	0	0	110
12.0	0	97	0	0	0	97
15.0	0	81	0	0	0	81
20.0	0	64	0	0	0	64
25.0	0	52	0	0	0	52

Reserve Life = 32.0 yrs   Reserve Half Life = 8.5 yrs   BOE Reserve Index = 13.4

YEARLY SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil Comp Grs	Gas Comp Grs	BOE Comp Grs	Oil Rev	Gas Rev	Other Rev	Total Crown	Non-Crown	Lease Expen	Other Expen	Total Cap	Aband Etc	BTax Cash Flow
	bbl/d	Mcf/d	boe/d	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	24	4	0	11	0	2	0	7	0	0	0	2
2012	0	23	4	0	35	0	7	0	19	0	0	0	9
2013	0	22	4	0	36	0	7	0	19	0	0	0	10
2014	0	20	3	0	40	0	9	0	18	0	0	0	12
2015	0	19	3	0	45	0	12	0	18	0	0	0	16
2016	0	18	3	0	43	0	11	0	17	0	0	0	15
2017	0	16	3	0	41	0	10	0	16	0	0	0	15
2018	0	15	3	0	39	0	9	0	16	0	0	0	14
2019	0	14	2	0	37	0	8	0	16	0	0	0	14
2020	0	13	2	0	36	0	7	0	15	0	0	0	13
2021	0	13	2	0	34	0	7	0	15	0	0	0	13
2022	0	12	2	0	32	0	6	0	14	0	0	0	12
2023	0	11	2	0	31	0	5	0	14	0	0	0	12
2024	0	10	2	0	29	0	5	0	14	0	0	0	11
2025	0	9	2	0	28	0	4	0	13	0	0	0	10
2026	0	9	1	0	27	0	4	0	13	0	0	0	10
2027	0	8	1	0	25	0	3	0	13	0	0	0	9
2028	0	8	1	0	24	0	3	0	13	0	0	0	9
2029	0	7	1	0	23	0	2	0	12	0	0	0	8
2030	0	7	1	0	22	0	2	0	12	0	0	0	8
SubT				0	639	0	124	0	294	0	0	0	222
13yr				0	201	0	11	0	143	0	0	3	43
Total				0	840	0	135	0	437	0	0	3	265
Discounted	5%			0	493	0	91	0	240	0	0	1	161
Cash	10%			0	335	0	67	0	158	0	0	0	110
Streams	15%			0	251	0	53	0	117	0	0	0	81
	20%			0	200	0	43	0	93	0	0	0	64

Sproule

Table 3

Proved+Probable Developed Producing

Eagleford Energy Inc.

Botha

102/06-22-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

PRODUCTION AND PRICE FORECAST

(As of Date: 2011-08-31)

Year	Gas Wells	Gas Daily Mcf/d	Gas Gross MMcf	Gas Co Grs MMcf	Gas Co Net MMcf	Gas Price $/Mcf
2011	1	468	57	3	2	3.70
2012	1	447	163	8	6	4.09
2013	1	417	152	8	6	4.56
2014	1	389	142	7	5	5.36
2015	1	363	133	7	5	6.58
2016	1	339	124	6	5	6.72
2017	1	317	116	6	4	6.86
2018	1	296	108	6	4	7.01
2019	1	276	101	5	4	7.15
2020	1	258	94	5	4	7.30
2021	1	241	88	5	4	7.46
2022	1	225	82	4	3	7.61
2023	1	210	77	4	3	7.76
2024	1	196	72	4	3	7.91
2025	1	183	67	3	3	8.06
2026	1	171	62	3	3	8.22
2027	1	159	58	3	3	8.38
2028	1	149	54	3	2	8.55
2029	1	139	51	3	2	8.71
2030	1	130	47	2	2	8.89
SubT			1847	96	74	
13yr			386	20	19	
Total			2234	116	93	

Table 3

Proved+Probable Developed Producing

Eagleford Energy Inc.

Botha

102/06-22-098-05W6/0

Zone: Debolt A, Prod. Start: 2011-09-01

SUMMARY OF RESERVES AND NET PRESENT VALUE

(As of Date: 2011-08-31)

Year	Oil	Gas	NGL	Sul	Roy	Other Income	Crown	Adjust	FH/ Indian	ORR	Min Taxes	Opex	NPI/ Other Expense
	Revenue						Royalties						
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	0	11	0	0	0	0	2	0	0	0	0	7	0
2012	0	35	0	0	0	0	7	1	0	0	0	19	0
2013	0	36	0	0	0	0	8	1	0	0	0	19	0
2014	0	40	0	0	0	0	10	1	0	0	0	18	0
2015	0	45	0	0	0	0	13	1	0	0	0	18	0
2016	0	43	0	0	0	0	12	1	0	0	0	17	0
2017	0	41	0	0	0	0	11	0	0	0	0	16	0
2018	0	39	0	0	0	0	10	0	0	0	0	16	0
2019	0	37	0	0	0	0	9	0	0	0	0	16	0
2020	0	36	0	0	0	0	8	0	0	0	0	15	0
2021	0	34	0	0	0	0	7	0	0	0	0	15	0
2022	0	32	0	0	0	0	6	0	0	0	0	14	0
2023	0	31	0	0	0	0	6	0	0	0	0	14	0
2024	0	29	0	0	0	0	5	0	0	0	0	14	0
2025	0	28	0	0	0	0	4	0	0	0	0	13	0
2026	0	27	0	0	0	0	4	0	0	0	0	13	0
2027	0	25	0	0	0	0	3	0	0	0	0	13	0
2028	0	24	0	0	0	0	3	0	0	0	0	13	0
2029	0	23	0	0	0	0	2	0	0	0	0	12	0
2030	0	22	0	0	0	0	2	0	0	0	0	12	0
SubT	0	639	0	0	0	0	130	6	0	0	0	294	0
13yr	0	201	0	0	0	0	12	1	0	0	0	143	0
Total	0	840	0	0	0	0	142	7	0	0	0	437	0

Year	Oper Inc	CEE	CDE	CCA	COGPE	Total Capital	Net Rev	Cum Net Rev	ARTC	Aband Cost	SK Tax	Cash Flow	Cum Cash Flow
		Capital											
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
2011	2	0	0	0	0	0	2	2	0	0	0	2	2
2012	9	0	0	0	0	0	9	11	0	0	0	9	11
2013	10	0	0	0	0	0	10	21	0	0	0	10	21
2014	12	0	0	0	0	0	12	34	0	0	0	12	34
2015	16	0	0	0	0	0	16	49	0	0	0	16	49
2016	15	0	0	0	0	0	15	65	0	0	0	15	65
2017	15	0	0	0	0	0	15	79	0	0	0	15	79
2018	14	0	0	0	0	0	14	93	0	0	0	14	93
2019	14	0	0	0	0	0	14	107	0	0	0	14	107
2020	13	0	0	0	0	0	13	120	0	0	0	13	120
2021	13	0	0	0	0	0	13	133	0	0	0	13	133
2022	12	0	0	0	0	0	12	145	0	0	0	12	145
2023	12	0	0	0	0	0	12	157	0	0	0	12	157
2024	11	0	0	0	0	0	11	168	0	0	0	11	168
2025	10	0	0	0	0	0	10	178	0	0	0	10	178
2026	10	0	0	0	0	0	10	188	0	0	0	10	188
2027	9	0	0	0	0	0	9	197	0	0	0	9	197
2028	9	0	0	0	0	0	9	206	0	0	0	9	206
2029	8	0	0	0	0	0	8	214	0	0	0	8	214
2030	8	0	0	0	0	0	8	222	0	0	0	8	222
SubT	222	0	0	0	0	0	222		0	0	0	222	
13yr	46	0	0	0	0	0	46		0	3	0	43	
Total	268	0	0	0	0	0	268		0	3	0	265	

Discounted Cash Streams NPV (M$)

discR%	5	10	12	15	18	20	25
BT Net	162	110	97	81	70	64	52
BT Cash Flow	161	110	97	81	70	64	52

Sproule

Table 4

Eagleford Energy Inc.

Botha

Entity Interests

as of August 31, 2011

Location Interest Start Date	Formation Status	Type Price	Interests	Lessor: Production Class	Burdens
100/06-14-098-05W6/0	Debolt A Producer: FLOWING GAS	Gas AB. AECO C Spot	5.2% WI	Crown: 2011	
102/06-22-098-05W6/0	Debolt A Producer: FLOWING GAS	Gas AB. AECO C Spot	5.2% WI	Crown: 2011	

Eagleford Energy Inc.

As of August 31, 2011
Proved Developed Producing
100/06-14-098-05W6/0 (Working Copy, Raw)

Status	Producer: FLOWING GAS	**Aprox. On-time**	100.00%
Field	Botha	**Rig Release**	Mar 1976
Pool	Debolt A	**WI**	5.20%
Unit		**RLI**	12.7
Operator	Canadian Natural Resources Limited	**Type**	PDP
Licensee	CANADIAN NATURAL RESOURCES		Raw

Technical Reserves at Sep 1, 2011 (Based on Dec. Analysis)

	Ultimate Reserves	Cumulative Production	Remaining Gross	Remaining WI
Oil (Mbbl)	0.0	0.0	0.0	0.0
Gas (MMcf)	13,295.0	10,341.3	2,953.7	153.6
Water (Mbbl)	245.4	104.0	141.4	7.4

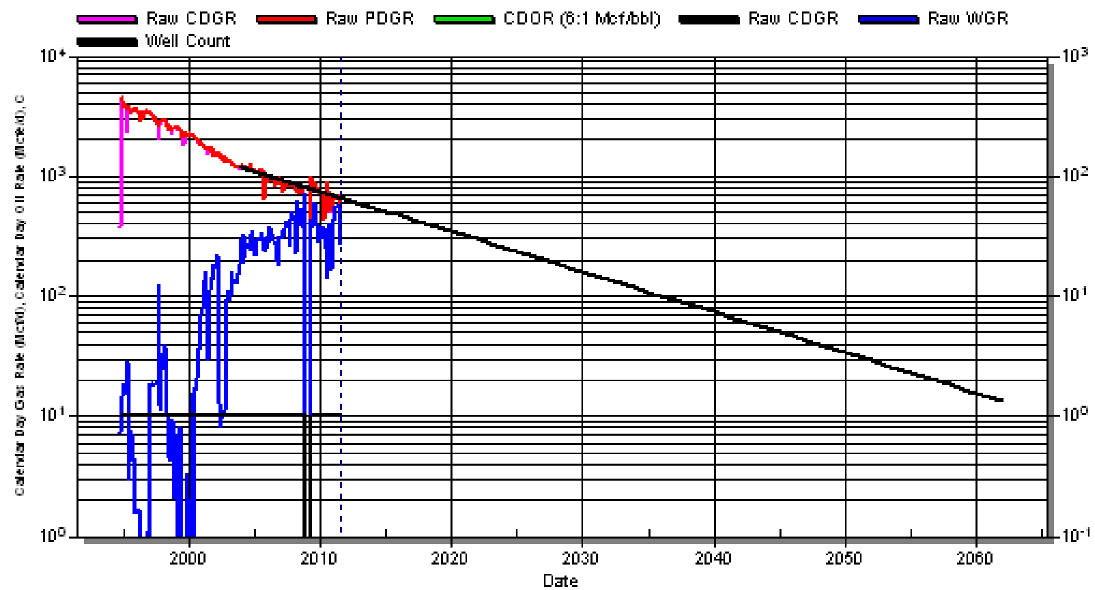
Declines

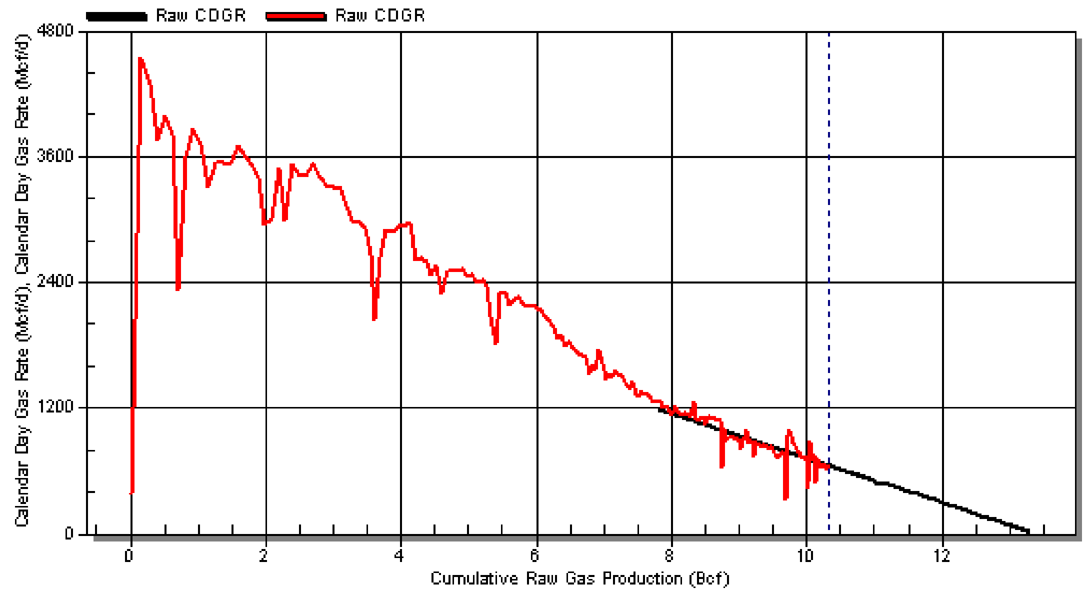
Segment	Start Date	Qi*	Di** (Eff.Sec)	Ni	Max***	Qf*
Gas 1	Aug 1, 2011	645.0	0.074707	0.00	1,398.9	5.0

*Qi, Qf units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d
**Di units: Gas #/yr, WGR #/Mcf, Water #/yr, Oil #/yr
***Max units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

Production (6 mo. History / 6 mo. Forecast)

Date	Well Count	CDOR (bbl/d)	CDGR (Mcf/d)	CDWR (bbl/d)	FGR (bbl/MMcf)
Feb 2011	1.0	0	639	36	55.9
Mar 2011	1.0	0	637	36	55.9
Apr 2011	1.0	0	642	35	55.0
May 2011	1.0	0	677	40	58.5
Jun 2011	1.0	0	610	17	27.1
Jul 2011	1.0	0	653	21	32.8
Aug 2011	1.0	0	643	31	47.9
Sep 2011	1.0	0	639	31	47.9
Oct 2011	1.0	0	635	30	47.9
Nov 2011	1.0	0	630	30	47.9
Dec 2011	1.0	0	626	30	47.9
Jan 2012	1.0	0	622	30	47.9





Eagleford Energy Inc.

As of August 31, 2011
Proved + Prob. Developed Producing
100/06-14-098-05W6/0 (Working Copy, Raw)

Status	Producer: FLOWING GAS	**Aprox. On-time**	100.00%
Field	Botha	**Rig Release**	Mar 1976
Pool	Debolt A	**WI**	5.20%
Unit		**RLI**	15.6
Operator	Canadian Natural Resources Limited	**Type**	P+PDP
Licensee	CANADIAN NATURAL RESOURCES		Raw

Technical Reserves at Sep 1, 2011 (Based on Dec. Analysis)

	Ultimate Reserves	Cumulative Production	Remaining Gross	Remaining WI
Oil (Mbbl)	0.0	0.0	0.0	0.0
Gas (MMcf)	13,997.0	10,341.4	3,655.6	190.1
Water (Mbbl)	279.0	104.0	175.0	9.1

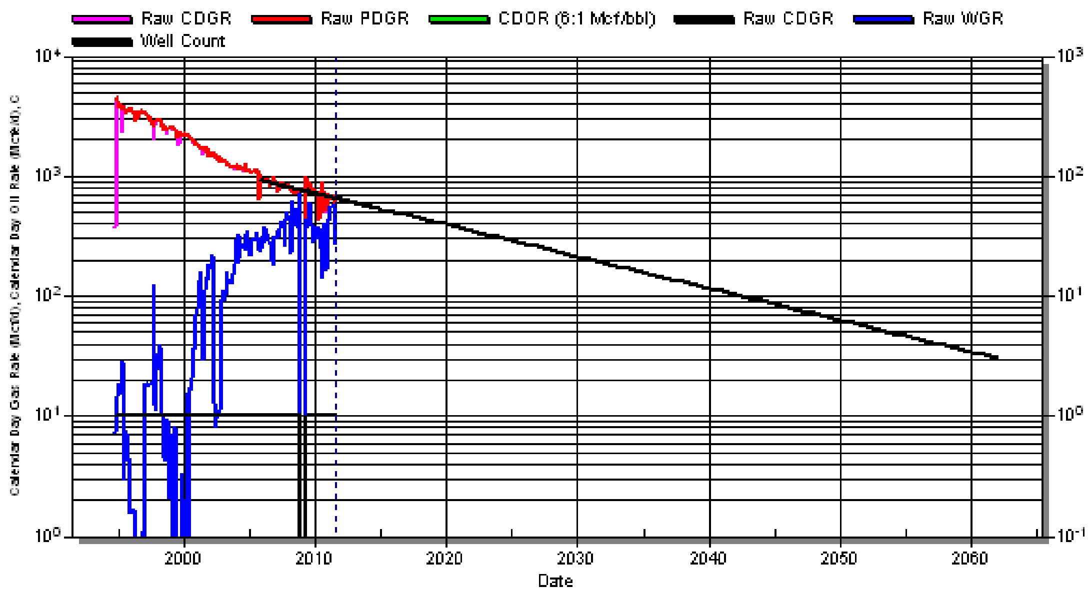
Declines

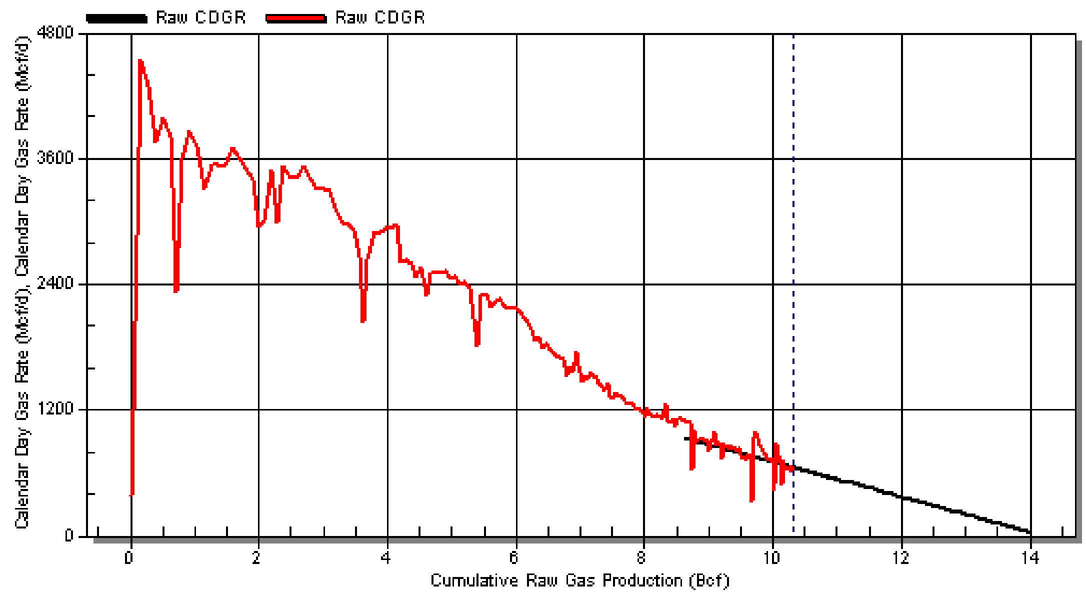
Segment	Start Date	Qi*	Di** (Eff.Sec)	Ni	Max***	Qf*
Gas 1	Aug 1, 2011	645.0	0.059326	0.00	1,398.9	5.0

*Qi, Qf units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d
**Di units: Gas #/yr, WGR #/Mcf, Water #/yr, Oil #/yr
***Max units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

Production (6 mo. History / 6 mo. Forecast)

Date	Well Count	CDOR (bbl/d)	CDGR (Mcf/d)	CDWR (bbl/d)	FGR (bbl/MMcf)
Feb 2011	1.0	0	639	36	55.9
Mar 2011	1.0	0	637	36	55.9
Apr 2011	1.0	0	642	35	55.0
May 2011	1.0	0	677	40	58.5
Jun 2011	1.0	0	610	17	27.1
Jul 2011	1.0	0	653	21	32.8
Aug 2011	1.0	0	643	31	47.9
Sep 2011	1.0	0	640	31	47.9
Oct 2011	1.0	0	637	30	47.9
Nov 2011	1.0	0	634	30	47.9
Dec 2011	1.0	0	630	30	47.9
Jan 2012	1.0	0	627	30	47.9





Eagleford Energy Inc.

As of August 31, 2011
Proved Developed Producing
100/09-21-098-05W6/0 (Working Copy, Raw)

Status	Producer: PUMPING GAS	**Aprox. On-time**	100.00%
Field	Botha	**Rig Release**	Feb 2003
Pool	Debolt A	**WI**	5.20%
Unit		**RLI**	1.4
Operator	Canadian Natural Resources Limited	**Type**	PDP
Licensee	CANADIAN NATURAL RESOURCES		Raw

Technical Reserves at Sep 1, 2011 (Based on Dec. Analysis)

	Ultimate Reserves	Cumulative Production	Remaining Gross	Remaining WI
Oil (Mbbl)	0.0	0.0	0.0	0.0
Gas (MMcf)	950.9	891.8	59.2	3.1
Water (Mbbl)	0.2	0.2	0.0	0.0

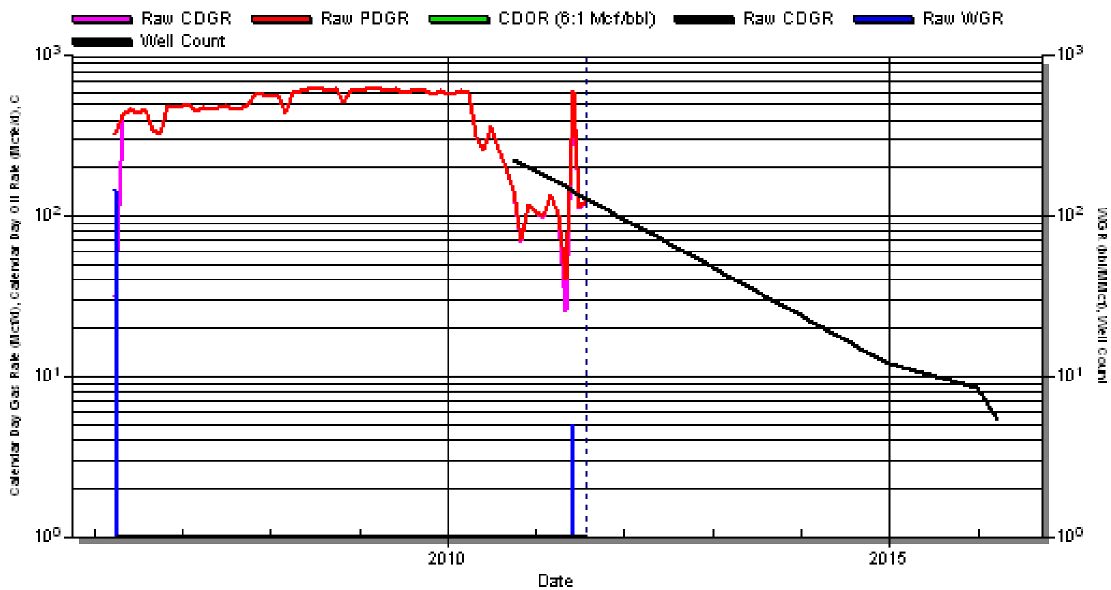
Declines

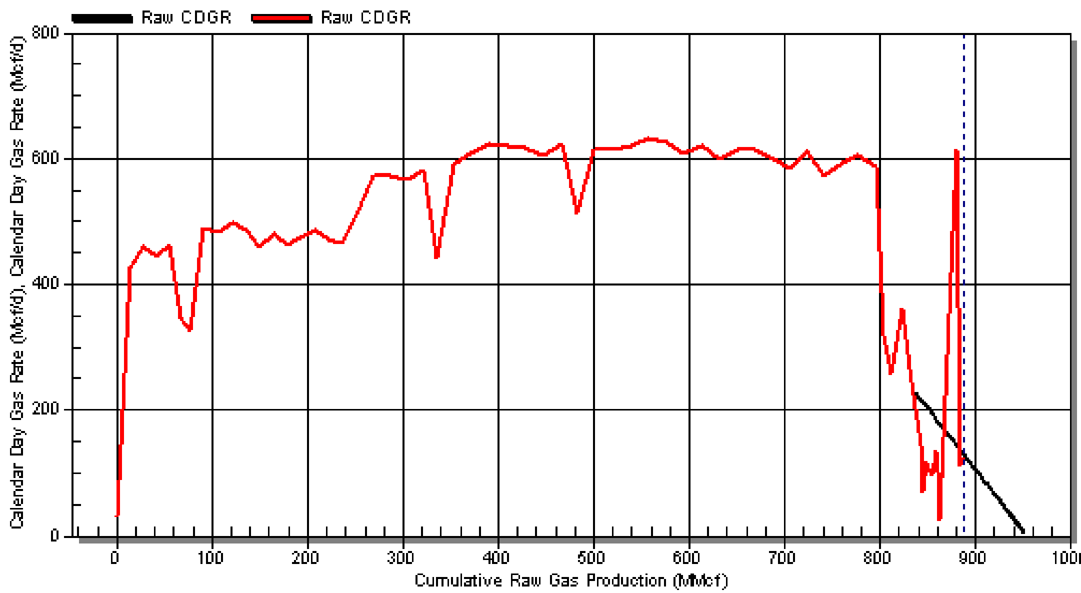
Segment	Start Date	Qi*	Di** (Eff.Sec)	Ni	Max***	Qf*
Gas 1	Aug 1, 2011	124.4	0.50	0.00	937.8	5.0

*Qi, Qf units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d
**Di units: Gas #/yr, WGR #/Mcf, Water #/yr, Oil #/yr
***Max units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

Production (6 mo. History / 6 mo. Forecast)

Date	Well Count	CDOR (bbl/d)	CDGR (Mcf/d)	CDWR (bbl/d)	FGR (bbl/MMcf)
Feb 2011	1.0	0	135	0	0.0
Mar 2011	1.0	0	103	0	0.0
Apr 2011	1.0	0	25	0	0.0
May 2011	1.0	0	613	3	4.9
Jun 2011	1.0	0	113	0	0.0
Jul 2011	1.0	0	124	0	0.0
Aug 2011	1.0	0	121	0	0.0
Sep 2011	1.0	0	114	0	0.0
Oct 2011	1.0	0	108	0	0.0
Nov 2011	1.0	0	102	0	0.0
Dec 2011	1.0	0	96	0	0.0
Jan 2012	1.0	0	90	0	0.0





Eagleford Energy Inc.

As of August 31, 2011
Proved + Prob. Developed Producing
100/09-21-098-05W6/0 (Working Copy, Raw)

Status	Producer: PUMPING GAS	**Aprox. On-time**	100.00%
Field	Botha	**Rig Release**	Feb 2003
Pool	Debolt A	**WI**	5.20%
Unit		**RLI**	2.7
Operator	Canadian Natural Resources Limited	**Type**	P+PDP
Licensee	CANADIAN NATURAL RESOURCES		Raw

Technical Reserves at Sep 1, 2011 (Based on Dec. Analysis)

	Ultimate Reserves	Cumulative Production	Remaining Gross	Remaining WI
Oil (Mbbl)	0.0	0.0	0.0	0.0
Gas (MMcf)	1,010.3	891.8	118.4	6.2
Water (Mbbl)	0.2	0.2	0.0	0.0

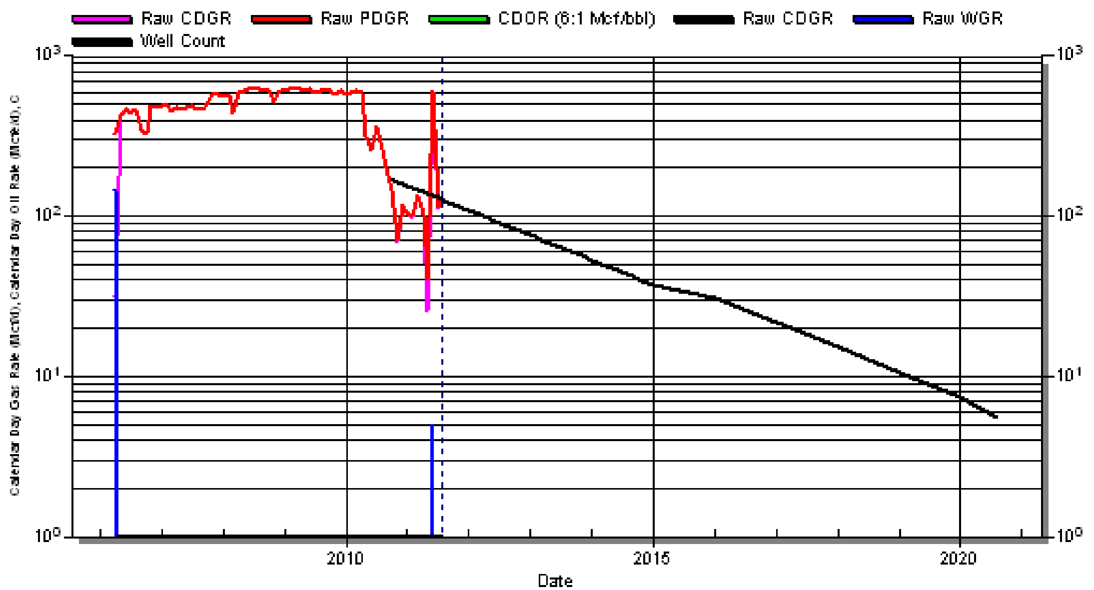
Declines

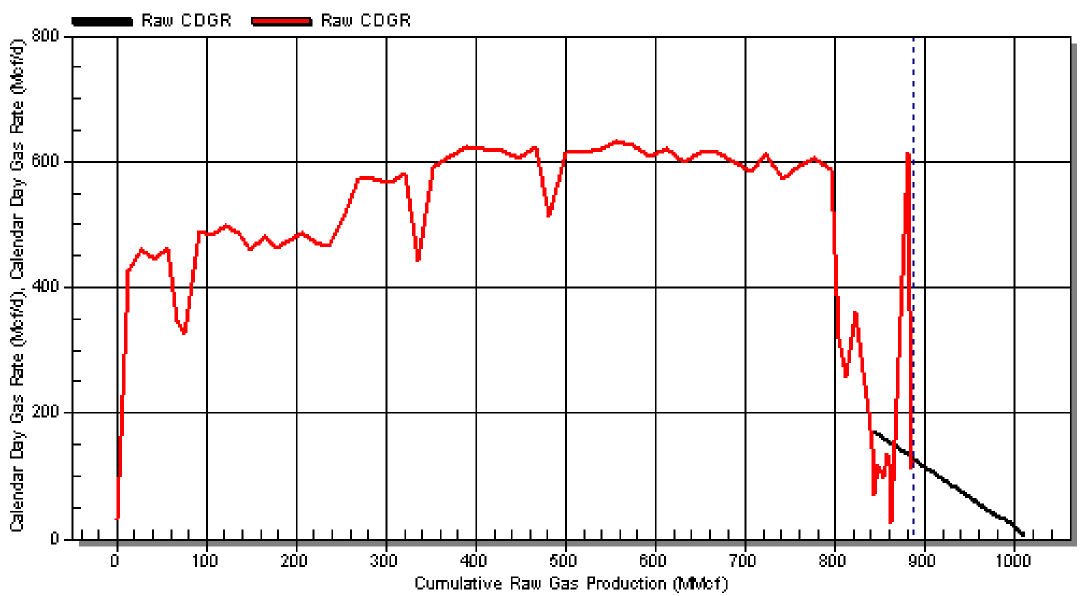
Segment	Start Date	Qi*	Di** (Eff.Sec)	Ni	Max***	Qf*
Gas 1	Aug 1, 2011	124.4	0.30	0.00	937.8	5.0

*Qi, Qf units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d
**Di units: Gas #/yr, WGR #/Mcf, Water #/yr, Oil #/yr
***Max units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

Production (6 mo. History / 6 mo. Forecast)

Date	Well Count	CDOR (bbl/d)	CDGR (Mcf/d)	CDWR (bbl/d)	FGR (bbl/MMcf)
Feb 2011	1.0	0	135	0	0.0
Mar 2011	1.0	0	103	0	0.0
Apr 2011	1.0	0	25	0	0.0
May 2011	1.0	0	613	3	4.9
Jun 2011	1.0	0	113	0	0.0
Jul 2011	1.0	0	124	0	0.0
Aug 2011	1.0	0	123	0	0.0
Sep 2011	1.0	0	119	0	0.0
Oct 2011	1.0	0	115	0	0.0
Nov 2011	1.0	0	112	0	0.0
Dec 2011	1.0	0	109	0	0.0
Jan 2012	1.0	0	106	0	0.0





Eagleford Energy Inc.

As of August 31, 2011
Proved Developed Producing
102/06-22-098-05W6/0 (Working Copy, Raw)

Status	Producer: FLOWING GAS	**Aprox. On-time**	100.00%
Field	Botha	**Rig Release**	Jan 1994
Pool	Debolt A	**WI**	5.20%
Unit		**RLI**	11.0
Operator	Canadian Natural Resources Limited	**Type**	PDP
Licensee	CANADIAN NATURAL RESOURCES		Raw

Technical Reserves at Sep 1, 2011 (Based on Dec. Analysis)

	Ultimate Reserves	Cumulative Production	Remaining Gross	Remaining WI
Oil (Mbbl)	0.0	0.0	0.0	0.0
Gas (MMcf)	7,545.6	5,454.1	2,091.6	108.8
Water (Mbbl)	47.6	29.1	18.6	1.0

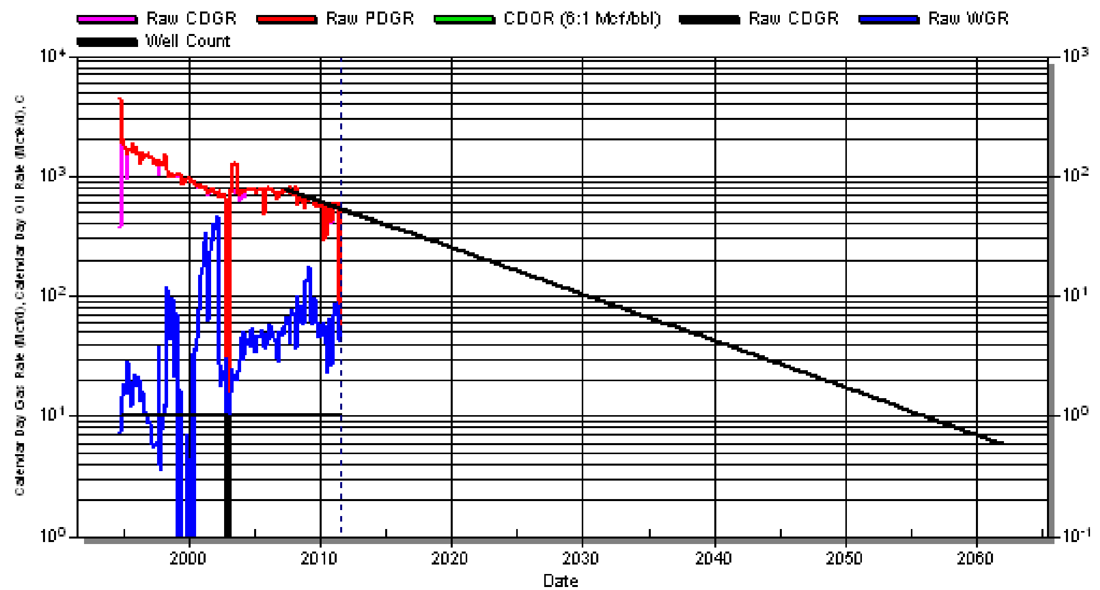
Declines

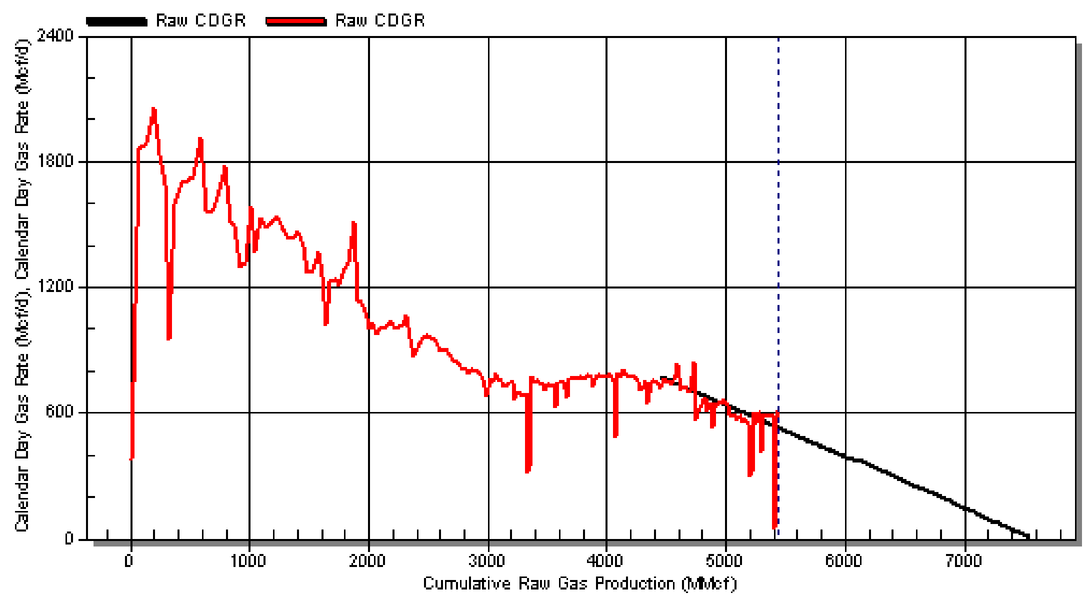
Segment	Start Date	Qi*	Di** (Eff.Sec)	Ni	Max***	Qf*
Gas 1	Aug 1, 2011	525.0	0.086069	0.00	1,192.5	5.0

*Qi, Qf units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d
**Di units: Gas #/yr, WGR #/Mcf, Water #/yr, Oil #/yr
***Max units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

Production (6 mo. History / 6 mo. Forecast)

Date	Well Count	CDOR (bbl/d)	CDGR (Mcf/d)	CDWR (bbl/d)	FGR (bbl/MMcf)
Feb 2011	1.0	0	586	5	8.5
Mar 2011	1.0	0	582	5	8.8
Apr 2011	1.0	0	578	5	8.6
May 2011	1.0	0	47	0	4.3
Jun 2011	1.0	0	577	2	4.3
Jul 2011	1.0	0	610	3	5.2
Aug 2011	1.0	0	523	5	8.9
Sep 2011	1.0	0	519	5	8.9
Oct 2011	1.0	0	515	5	8.9
Nov 2011	1.0	0	511	5	8.9
Dec 2011	1.0	0	508	5	8.9
Jan 2012	1.0	0	504	4	8.9





Eagleford Energy Inc.

As of August 31, 2011
Proved + Prob. Developed Producing
102/06-22-098-05W6/0 (Working Copy, Raw)

Status	Producer: FLOWING GAS	**Aprox. On-time**	100.00%
Field	Botha	**Rig Release**	Jan 1994
Pool	Debolt A	**WI**	5.20%
Unit		**RLI**	14.1
Operator	Canadian Natural Resources Limited	**Type**	P+PDP
Licensee	CANADIAN NATURAL RESOURCES		Raw

Technical Reserves at Sep 1, 2011 (Based on Dec. Analysis)

	Ultimate Reserves	Cumulative Production	Remaining Gross	Remaining WI
Oil (Mbbl)	0.0	0.0	0.0	0.0
Gas (MMcf)	8,318.0	5,455.1	2,862.8	148.9
Water (Mbbl)	54.5	29.1	25.4	1.3

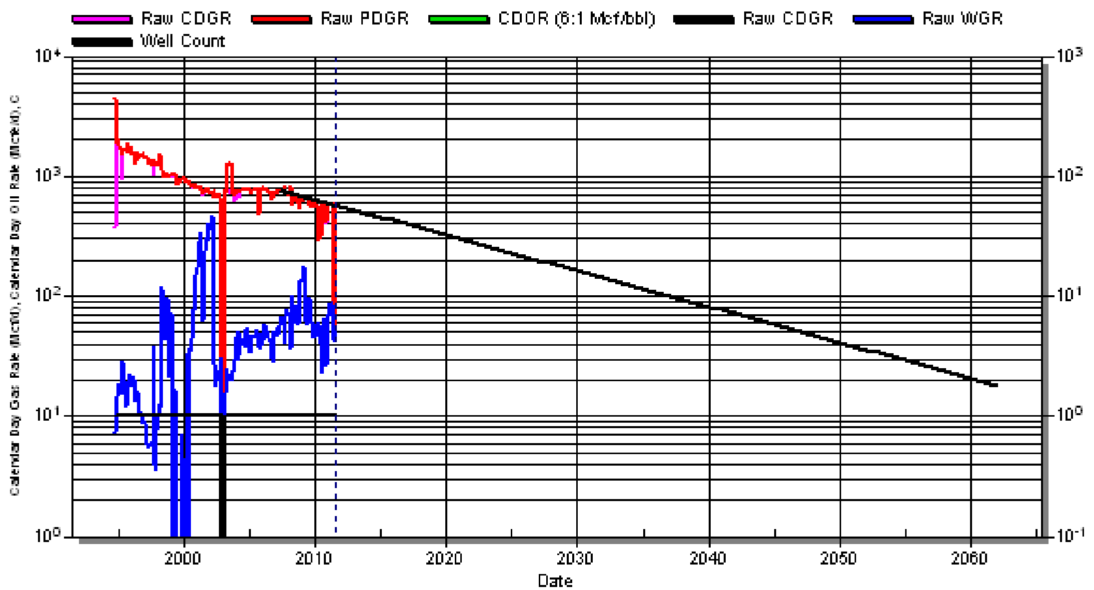
Declines

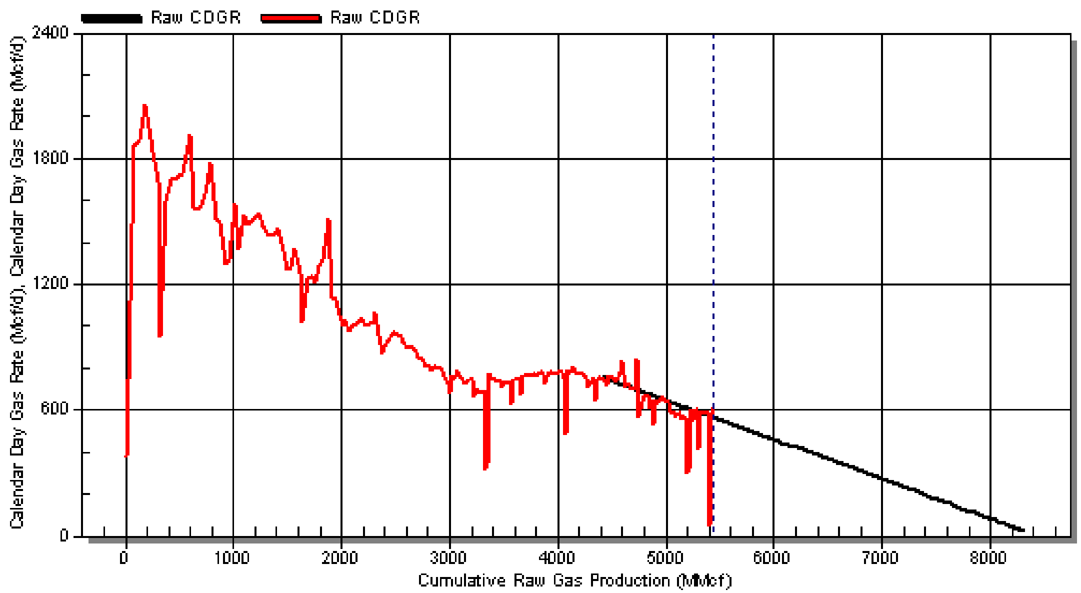
Segment	Start Date	Qi*	Di** (Eff.Sec)	Ni	Max***	Qf*
Gas 1	Aug 1, 2011	559.6	0.066445	0.00	1,192.5	5.0

*Qi, Qf units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d
**Di units: Gas #/yr, WGR #/Mcf, Water #/yr, Oil #/yr
***Max units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

Production (6 mo. History / 6 mo. Forecast)

Date	Well Count	CDOR (bbl/d)	CDGR (Mcf/d)	CDWR (bbl/d)	FGR (bbl/MMcf)
Feb 2011	1.0	0	586	5	8.5
Mar 2011	1.0	0	582	5	8.8
Apr 2011	1.0	0	578	5	8.6
May 2011	1.0	0	47	0	4.3
Jun 2011	1.0	0	577	2	4.3
Jul 2011	1.0	0	610	3	5.2
Aug 2011	1.0	0	558	5	8.9
Sep 2011	1.0	0	555	5	8.9
Oct 2011	1.0	0	552	5	8.9
Nov 2011	1.0	0	548	5	8.9
Dec 2011	1.0	0	545	5	8.9
Jan 2012	1.0	0	542	5	8.9





Eagleford Energy Inc.

Haynes

SUMMARY OF THE EVALUATION OF THE P.& N.G. RESERVES

(As of Date: 2011-08-31)

	Remaining Reserves			Net Present Values Before Income Taxes				
	Gross	Company						
	100%	Gross	Net	@ 0%	@ 5%	@ 10%	@ 15%	@ 20%
				M$	M$	M$	M$	M$

No reserves assigned to this area.

Table 1

Eagleford Energy Inc.

Haynes,

WELL LIST / RESERVOIR DATA

GAS RESERVES

Location	Reserve Category	Analysis Type	Drainage Area	Net Pay	Poros.	Water Sat	Temp.	Press.	Comp.	Original Gas In-Place	Recov. Factor	Original Recoverable Raw Gas
			ac	ft	%	%	degF	psia	z	MMcf	%	MMcf
100/07-22-038-24W4/0	NRA											0
Total Technical Reserves												0
Adjusted To Econ. Reserves												0

Appendix A — Definitions

The following definitions form the basis of our classification of reserves and values presented in this report. They have been prepared by the Standing Committee on Reserves Definitions of the Petroleum Society of the CIM ("CIM"), incorporated in the Society of Petroleum Evaluation Engineers ("SPEE") Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and specified by National Instrument 51-101 ("NI 51-101").

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
- a remaining reserve life of 50 years.

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

1. Proved Reserves

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.

2. Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

3. Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves have not been considered in this report.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Each of the reserves categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

4. Developed Reserves

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

5. Developed Producing 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.

6. Developed Non-Producing Reserves

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.

7. Undeveloped Reserves

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 subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

8. Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Sections 1, 2 and 3 are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

a. There is a 90% probability that at least the estimated proved reserves will be recovered.

b. There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.

c. There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

9. **Remaining Recoverable Reserves** are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.

10. **Company Gross Reserves** are the Company's working interest share of the remaining reserves, before deduction of any royalties.

11. **Company Net Reserves** are the gross remaining reserves of the properties in which the Company has an interest, less all Crown, freehold, and overriding royalties and interests owned by others.

12. **Net Production Revenue** is income derived from the sale of net reserves of oil, non-associated and associated gas, and gas by-products, less all capital and operating costs.

13. **Fair Market Value** is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

14. **Barrels of Oil Equivalent (BOE) Reserves** – BOE is the sum of the oil reserves, plus the gas reserves divided by a factor of 6, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels. Equivalent reserves can also be expressed in thousands of cubic feet of gas equivalent (McfGE) using a conversion ratio of 1 bbl:6 Mcf.

15. **Oil (or Crude Oil)** – a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas.

16. **Gas (or Natural Gas)** – a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs, but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

17. **Non-Associated Gas** – an accumulation of natural gas in a reservoir where there is no crude oil.

18. **Associated Gas** – the gas cap overlying a crude oil accumulation in a reservoir.

19. **Solution Gas** – gas dissolved in crude oil.

20. **Natural Gas Liquids** – those hydrocarbon components that can be removed from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

Appendix B — Prices (As of August 31, 2011)

Sproule's short-term outlook for oil and gas prices adopts the NYMEX futures market for the forecast period ending **August 31, 2014**. The forecast used in this evaluation was derived as of **August 31, 2011**, and reflects the arithmetic average of the futures market at the close of trading each day, for the month prior to the Termination of Trading date for an **September** contract. The oil price forecasts are based on the NYMEX Division light, sweet (low-sulphur) crude oil futures contract, which specifies the West Texas Intermediate crude as a deliverable, and the gas price forecasts are based on the NYMEX Division Henry Hub natural gas futures contract.

The NYMEX oil and gas futures prices are the foundation of Sproule's energy pricing models in the early years. This data is combined with Sproule's assumptions respecting long-term prices, inflation rates, and exchange rates, together with estimates of transportation costs and prices of competing fuels, to forecast wellhead and plantgate prices for Canadian oil, natural gas, and natural gas by-product production. The following paragraphs briefly describe some of the key considerations included in Sproule's long-term outlook for oil and natural gas price forecasts.

Oil Prices

In the long term, the price of oil will be governed by supply and demand, and the degree that OPEC is able to manage supply will be a major determinant in establishing oil prices for the next 10 years. A strong demand for crude oil, instability in the Middle East, and the increasing cost of exploration and development has served to increase the price of crude oil throughout the world. In recognition of these factors, Sproule's long-term forecast has been set at **$90.00 US** per barrel (2011 dollars).

Transmission costs, a significant item in forecasting Canadian wellhead prices, are expected to increase at rates that are generally less than the rate of inflation. The exchange rate ($U.S. per $Canadian) reflects a projection of **1.01.**

The oil price forecasts set out in Table P-1 are based on a forecast of prices for West Texas Intermediate crude at Cushing, Oklahoma. The price of this marker crude is expected to directly reflect world oil prices over the forecast period. The Edmonton par price is for a 40 to 45 degree API crude having less than 0.5 percent sulphur. The actual wellhead price of oil will vary with the quality of the crude and the cost of the transportation from the wellhead to the trading hub in Edmonton. This cost, which is referred to as the price differential, is based on the actual difference between the revenue received at the wellhead and the

Edmonton par price postings of major crude oil purchasers. In the absence of actual crude oil price statistics, the differential is based on the price of similar quality crude in the area.

Natural Gas Prices

The New York Mercantile Exchange (NYMEX) posted price for gas bought and sold at the Henry Hub in Louisiana has become a common index for Canadian natural gas producers with access to the American marketplace. In Alberta and Saskatchewan, the AECO price at Suffield is a reflection of the market price for natural gas sold locally, and the Sumas price on the British Columbia/ Washington border is critical to the BC producer.

Developing a balance between supply and demand for natural gas produced in Western Canada has proved a challenge to the Canadian producer, where drilling activity, which leads to gas well completions, must serve to replace declining gas well production and fill new or expanded pipeline systems. In the early 1990's, the Alberta, Saskatchewan and BC price of natural gas has often been suppressed, relative to the market opportunities in the United States, because local natural gas delivery exceeded the pipeline capacity leaving the provinces. Various new pipeline projects have provided sufficient market access to allow Western Canadian producers to double their production since 1986. With each new pipeline, the drilling activity expanded to ensure the pipeline was full and continued until a surplus in local productive capacity would once again depress the price of natural gas in the western provinces. An additional 1.1 Bcf per day of pipeline capacity completed during the 1998/99 winter, followed by 1.2 Bcf per day of capacity in the Alliance Pipeline, created additional market access for Canadian gas. This has strengthened the Canadian gas price and has created an integrated North American market. The average long-term price at Alberta AECO-C is approximately **$Cdn 6.00** per MMBtu in real terms. In the United States, Sproule maintains a long-term threshold of **$6.50 U.S.** per MMBtu, in real terms. Detailed price schedules are set out in Table P-2. The actual plantgate price will vary with the heat content of the natural gas and the cost of transportation from the plantgate to the trading hub. In the absence of actual natural gas price statistics, the differential is based on the price of natural gas in the area.

The evaluation of uncontracted shut-in gas reserves in Western Canada considers the proximity to existing infrastructure, and the production start date varies with the magnitude of the reserves and the development plans of the operator. To the extent the plant and gathering facilities of sufficient capacity are currently available, the production start date is deferred a year or two and the economics of plant development may curtail the production of the reserves to an average daily rate of 1.0 MMcfpd per 3.5 Bcf of reserves. For reserves located in remote areas, or reserves that are considered of poor quality, the production start date is no earlier than **2014**.

Natural Gas By-Products

Ethane, propane, butanes, and pentanes plus prices were forecast to continue their historic relationships with crude prices in major Eastern Canadian and U.S. market areas. Ethane prices are expected to increase from present levels at a rate that corresponds to the local Alberta spot price of gas. Sulphur prices reflect the current market. The price forecasts for natural gas by-products are set out in Table P-1. The prices for these by-products were adjusted in this report to reflect the actual prices received at the plantgate.

Table P-1
Summary of Price Forecasts and Inflation and Exchange Rates ($Cdn)
Effective August 31, 2011

	Light Crude Oil				Heavy & Medium Oil					Natural Gas Liquids & Sulphur						
Year	WTI Cushing Oklahoma 40°API ($US/bbl)	Edmonton Par Price 40°API ($/bbl)	Synthetic Crude Oil Edmonton 34°API ($/bbl)	Cromer LSB 35°API ($/bbl)	Hardisty Heavy 12°API ($/bbl)	Hardisty Lloyd Blend 20.5°API ($/bbl)	Western Canada Select 20.5°API ($/bbl)	Cromer Medium 29.3°API ($/bbl)	Hardisty Bow River 24.9°API ($/bbl)	Ethane Plant Gate ($/bbl)	Edmonton Propane ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Pentanes Plus ($/bbl)	Plant Gate Sulphur ($/LT	Operating & Capital Cost Inflation Rate (%/Yr)	Exchange Rate ($US/$Cdn)
Historical																
2007	72.27	77.06			44.77	51.93	52.24	65.36	53.16	18.42	49.53	63.71	77.33	38.02	2.0	0.935
2008	99.59	102.85	107.11		76.32	82.58	83.62	93.05	83.85	22.59	58.80	75.09	104.70	303.84	1.0	0.943
2009	61.63	66.20	69.20	63.86	55.65	58.49	58.66	62.77	59.71	11.61	38.39	44.13	68.13	-5.08	2.0	0.880
2010	79.43	77.80	80.89	76.57	62.30	67.17	67.21	73.67	68.27	11.53	46.98	57.04	84.21	57.18	1.0	0.971
Forecast																
2011	90.28	87.42	91.42	84.42	61.19	69.94	69.94	80.71	69.94	9.83	53.34	78.92	93.46	50.00	2.0	1.012
2012	93.23	90.32	94.32	87.32	63.23	72.26	72.26	83.39	72.26	10.93	55.11	81.54	96.57	51.00	2.0	1.012
2013	95.58	92.62	96.62	89.62	64.84	74.10	74.10	85.52	74.10	12.21	56.51	83.62	99.03	52.02	2.0	1.012
2014	95.97	92.99	96.99	89.99	65.10	74.40	74.40	85.86	74.40	14.43	56.74	83.96	99.42	79.59	2.0	1.012
2015	97.42	94.41	98.41	91.41	66.09	75.53	75.53	87.16	75.53	17.82	57.60	85.23	100.93	81.18	2.0	1.012
2016	99.37	96.32	100.32	93.32	67.42	77.05	77.05	88.92	77.05	18.20	58.76	86.95	102.97	82.81	2.0	1.012
2017	101.35	98.26	102.26	95.26	68.78	78.61	78.61	90.72	78.61	18.60	59.95	88.71	105.05	84.46	2.0	1.012
2018	103.38	100.25	104.25	97.25	70.17	80.20	80.20	92.55	80.20	19.00	61.16	90.50	107.17	86.15	2.0	1.012
2019	105.45	102.27	106.27	99.27	71.59	81.82	81.82	94.42	81.82	19.41	62.40	92.33	109.34	87.87	2.0	1.012
2020	107.56	104.33	108.33	101.33	73.03	83.47	83.47	96.33	83.47	19.82	63.66	94.19	111.55	89.63	2.0	1.012
2021	109.71	106.44	110.44	103.44	74.51	85.15	85.15	98.27	85.15	20.25	64.94	96.10	113.80	91.42	2.0	1.012
Thereafter	Escalation Rate of 2%															

Table P-2
Natural Gas Price Forecasts, Various Trading Points ($Cdn / MMbtu)
Effective August 31, 2011

Year	Alberta Gas Reference Price Plant Gate	AECO-C Spot	Aggregator Intra-Alta	Alliance Pipeline	B.C. Average Wellhead	B.C. Westcoast Station 2	Huntingdon / Sumas 30-day Spot	Dawn	Henry Hub Price ($US / MMbtu)
Historical									
2007	6.20	6.65	6.34	6.04	6.00	6.40	7.01	7.69	6.86
2008	7.88	8.15	8.08	7.91	7.33	8.20	8.78	9.60	9.04
2009	3.85	4.19	3.91	3.35	3.29	4.17	4.54	4.91	4.01
2010	3.88	4.16	3.14	3.37	3.04	4.01	4.43	4.89	4.39
Forecast									
2011	3.27	3.55	2.65	2.57	2.87	3.49	4.04	4.32	4.12
2012	3.69	3.94	3.11	3.07	3.26	3.88	4.43	4.72	4.52
2013	4.17	4.41	3.63	3.63	3.73	4.35	4.90	5.18	4.99
2014	4.99	5.21	4.48	4.48	4.53	5.15	5.70	5.98	5.80
2015	6.21	6.43	5.70	5.70	5.75	6.37	6.92	7.20	7.04
2016	6.39	6.57	6.05	5.84	5.89	6.51	7.06	7.34	7.18
2017	6.54	6.71	6.20	5.99	6.03	6.65	7.20	7.49	7.32
2018	6.68	6.86	6.34	6.13	6.18	6.80	7.35	7.63	7.47
2019	6.83	7.00	6.49	6.28	6.32	6.94	7.49	7.78	7.62
2020	6.98	7.15	6.64	6.43	6.47	7.09	7.64	7.93	7.77
2021	7.13	7.31	6.79	6.58	6.63	7.25	7.80	8.08	7.92
Thereafter					Escalation Rate of 2%				

Appendix C — Abbreviations

This appendix contains a list of abbreviations that may be found in Sproule reports, as well as a table comparing Imperial and Metric units. Two conversion tables, used to prepare this report, are also provided.

AOF	absolute open flow
ARTC	Alberta Royalty Tax Credit
BOE	barrels of oil equivalent
bopd	barrels of oil per day
bwpd	barrels of water per day
Cr	Crown
DCQ	daily contract quantity
DSU	drilling spacing unit
FH	Freehold
GCA	gas cost allowance
GOR	gas-oil ratio
GORR	gross overriding royalty
LPG	liquid petroleum gas
McfGE	thousands of cubic feet of gas equivalent
Mcfpd	thousands of cubic feet per day
MPR	maximum permissive rate
MRL	maximum rate limitation
NC	‘new’ Crown
NCI	net carried interest
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
OC	‘old’ Crown
ORRI	overriding royalty interest
P&NG	petroleum and natural gas
PSU	production spacing unit
PVT	pressure-volume-temperature
TCGSL	TransCanada Gas Services Limited
UOCR	Unit Operating Cost Rates for operating gas cost allowance
WI	working interest

Imperial Units			Metric Units	
M (10^3)	one thousand	**Prefixes**	k (10^3)	one thousand
MM (10^6)	million		M (10^6)	million
B (10^9)	one billion		G (10^9)	one billion
T (10^{12})	one trillion		T (10^{12})	one trillion
			E (10^{18})	one milliard
in.	inches	**Length**	cm	centimetres
ft	feet		m	metres
mi	mile		km	kilometres
ft^2	square feet	**Area**	m^2	square metres
ac	acres		ha	hectares
cf or ft^3	cubic feet	**Volume**	m^3	cubic metres
scf	standard cubic feet			
gal	gallons		L	litres
Mcf	thousand cubic feet			
Mcfpd	thousand cubic feet per day			
MMcf	million cubic feet			
MMcfpd	million cubic feet per day			
Bcf	billion cubic feet (10^9)			
bbl	barrels		m^3	cubic metre
Mbbl	thousand barrels			
stb	stock tank barrel		stm^3	stock tank cubic metres
bbl/d	barrels per day		m^3/d	cubic metre per day
bbl/mo	barrels per month			
Btu	British thermal units	**Energy**	J	joules
			MJ/m^3	megajoules per cubic metre (10^6)
			TJ/d	terajoule per day (10^{12})
oz	ounce	**Mass**	g	gram
lb	pounds		kg	kilograms
ton	ton		t	tonne
lt	long tons			
Mlt	thousand long tons			
psi	pounds per square inch	**Pressure**	Pa	pascals
			kPa	kilopascals (10^3)
psia	pounds per square inch absolute			
psig	pounds per square inch gauge			
		Temperatur		
°F	degrees Fahrenheit	**e**	°C	degrees Celsius
°R	degrees Rankine		K	Kelvin
M$	thousand dollars	**Dollars**	k$	thousand dollars

Imperial Units			Metric Units	
sec	second	**Time**	s	second
min	minute		min	minute
hr	hour		h	hour
day	day		d	day
wk	week			week
mo	month			month
yr	year		a	annum

Conversion Factors — Metric to Imperial		
cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
10,000 cubic metres (ha·m)	x 8.107133	= acre feet (ac-ft)
$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf) (@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
tonnes (t)	x 0.9842064	= long tons (LT)
kilograms (kg)	x 2.204624	= pounds (lb)
litres (L)	x 0.2199692	= gallons (Imperial)
litres (L)	x 0.264172	= gallons (U.S.)
cubic metres per million cubic metres ($m^3/10^6m^3$) (C_3)	x 0.177496	= barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia)
$m^3/10^6m^3$) (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$) (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)
Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise

Conversion Factors — Imperial to Metric		
barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m^3) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m^3 (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m^3 (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m^3 (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m^3 (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m^3 (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x 0.02817399	= 1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10^3m^2)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10^4m^3) (ha·m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf)	x 0.03743222	= megajoules per cubic metre (MJ/m^3)
(@ 14.65 psia, 60°F)		(@ 101.325 kPaa, 15°C)
$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule ($/GJ)
$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= $\$/10^3m^3$ (@ 101.325 kPaa, 15°C)
$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= $\$/10^3m^3$ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
$/bbl	x 6.29287	= $\$/m^3$ (average for 30°-50° API)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m^3/m^3)
horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t)
pounds (lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m^3)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m^3)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C_3)	x 5.6339198	= cubic metres per million cubic metres ($m^3/10^6m^3$)
bbl/MMcf (C_4)	x 5.6367593	= ($m^3/10^6m^3$)
bbl/MMcf (C_{5+})	x 5.6403087	= ($m^3/10^6m^3$)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres ($t/10^6m^3$)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C_{5+})	x 161.3577	= millilitres per cubic meter (mL/m^3)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C_{5+})	x 134.3584	= (mL/m^3)
degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa·s)

Appendix D — General Evaluation Parameters

Royalties and Mineral Taxes

The lessor and overriding royalties were based on existing agreements and government regulations. The Crown royalty rates and the Freehold Mineral Taxes were based upon existing provincial regulations.

Changes to royalties enacted by legislation in Alberta have been included in this report.

Operating and Capital Costs

Operating and capital costs were based on current costs and were escalated to the dates when these costs would be incurred. When escalated, the operating costs and capital costs were escalated based upon the schedule of escalation factors included in Appendix B, Table P-1. Where applicable, a fee for dehydration, gathering, compression and processing was applied against royalty gas and credited to the Company.

By-Product Reserves

The Company's proved and probable by-product reserves are associated with a number of the properties evaluated in this report. The by-product reserves and production forecasts were based on the recovery rates determined from revenue statements (barrels per MMcf or long tons per MMcf of natural gas) or from natural gas compositional analysis and the natural gas reserves and production forecasts.

Future prices were estimated based on the forecasts presented in Appendix B.

Gas Cost Allowance

The operating portion of the gas cost allowance (GCA) has been included with each individual entity. The value has been estimated based on either custom processing fees or actual operating costs, as reported by the Facility Cost Centre (FCC) operator. The Alberta Department of Energy Unit Operating Cost Rates (UOCR) Plant Types, or UOCR-designated facility rates, are replaced by the FCC in 2009. These FCC costs have been estimated based on the old custom processing fees or UOCR's.

The Corporate Effective Royalty Rate is replaced by the Facility Effective Royalty Rate (FERR) in 2009. The FERR will include a capital cost component, which will replace the Capital GCA pools. As this GCA is in the transitional stages of changing to new regulations, the capital portion of the GCA is estimated based on the historical Capital GCA pools until enough information is available to include it with the operating portion.

Abandonment and Reclamation

Well abandonment and disconnect costs were estimated and included in our report at the individual entity level for all wells that were assigned reserves. No allowance for surface lease reclamation and salvage value was included. No abandonment costs have been estimated for suspended wells, gathering systems, batteries, plants, or processing facilities.

Corporate Income Taxes

At the request of the Company, income taxes have not been considered in this report. However, for completeness, the procedure used in calculating Canadian income tax is set out below.

All royalties on production from Indian Lands are deductible. Non-Crown (that is, freehold or overriding) royalties are subdivided as follows, for income tax calculations:

(a) Production royalties are those non-Crown royalties which are subject to payments to the Crown (including Freehold Mineral Taxes (Alberta), Freehold Production Taxes (Saskatchewan), and Incremental Taxes (Manitoba)).

(b) Resource Royalties are those non-Crown royalties which are not subject to non-deductible Crown payments.

The procedure for calculating Canadian income taxes used in this report, is as follows:

1. Determine revenues from the production and sale of oil, gas, and by-products, including sulphur, from field processing of gas of other producers, and from gas production royalties. (This calculation is to be made gross of any Crown charges.)

2. Deduct operating and direct overhead costs.

3. Deduct capital cost allowance (depreciation).

4. Deduct production royalties paid or payable.

5. Deduct Crown charges (Crown royalties and freehold mineral taxes).

6. Deduct resource royalties paid.

7. Deduct intangible costs:

   - 10 percent of non-amortized balance at end of year for Canadian Oil and Gas Property Expense (COGPE),

   - 30 percent of non-amortized balance at end of year for Canadian Development Expense (CDE),

   - 100 percent of Canadian Exploration Expense (CEE).

8. Deduct interest, NPI expenses, abandonment costs, and Saskatchewan capital tax.

9. Deduct earned depletions. This deduction was discontinued many years ago. However, some companies could have a residual balance available. If so, the amount that can be claimed is the lesser of production profits (for this purpose includes resource royalties earned and is reduced by deduction for resource royalties paid or payable, and COGPE, CDE, and CEE deductions and interest) and the remaining balance of earned depletion.

10. Add resource royalties received or receivable, and other income (including NPI income).

11. Calculate taxable income for federal and provincial tax purposes, which equals the amount by which the aggregate of Items 1 and 10 exceed the aggregate of Items 2 through 9.

12. Calculate federal income taxes payable by multiplying federal taxable income by the federal tax rate.

13. Calculate provincial income taxes payable by multiplying provincial taxable income by the appropriate provincial tax rate.

Processing Income

Some clarification is required with regard to the definition of field processing plants. The following describes plants where the processing revenue would be included in the resource revenue.

(a) Field separation and dehydration facilities.

(b) A natural gas processing plant which processes raw natural gas to the point of acceptance by a common carrier, including the processing of hydrogen sulphide.

(c) Fully integrated plants that take raw natural gas through the whole process of converting such gas to natural gas liquids and to further convert the natural gas liquids to liquefied petroleum products.

The following describes plants where the processing revenue would not be included in the resource revenue.

(a) Straddle plants which enhance the recovery of natural gas liquids.

(b) Any part of a natural gas processing plant that is devoted primarily to the recovery of ethane.

(c) Plants used in the processing of heavy crude oil or a tar sands deposit.

Capital Cost Allowance

Capital cost allowance (CCA) is the rate at which the government allows depreciation on tangible capital investment items.

The principal classes of interest to an oil or gas producer for new capital investments are:

Class	**Description**	**Write-Off**
2	Oil or gas transmission pipelines of more than 15 years' life.	6% declining balance
7	Vessels, including offshore drilling vessels.	25% declining balance

Class	Description	Write-Off
8	Oil or gas transmission pipelines with a life of 15 years or less, any refineries, separators not included in Class 43, compressors.	20% declining balance
12	The cost, after November 16, 1978, of removing overburden after the start of production at a mine. Computer software, other than systems software.	100%
28	Mining assets acquired in a major expansion of a mine or before the start of production which would otherwise be in Class 41.	25% declining balance
41	Drilling rigs, gas or oil well equipment. Oil or gas gathering lines leading to a transmission pipeline or natural gas processing plant, and field processing plants. Automotive equipment. Mining buildings, equipment, social capital and spur lines not included in Class 28. Electric data processing equipment including systems software.	25% declining balance
43	Refineries acquired after May 8, 1972. Plants acquired after April 10, 1978 to upgrade heavy oil, straddle plants, and any part of a gas processing plant devoted primarily to the recovery of ethane.	30% declining balance

When using the declining balance, the prescribed rate is applied to the undepreciated portion of the capital costs in a particular class at the end of the fiscal year. It is not necessary to claim full capital cost allowance, and any amount from zero to the stated maximum can be claimed. In the year that the capital cost is incurred, only one-half of the stated maximum is allowed.

The asset descriptions contained in the Income Tax Act are drafted precisely. If an asset does not exactly fit the description of a class, then it is not to be included in that class.

Class 8 is a residual class. If property does not qualify for inclusion in any other class, and if it is not specifically excluded from Class 8, then it falls into Class 8.

Resource Allowance

As of January 1, 2007, there is no further deductible percentage for Resource Allowance.

Intangible Costs

Intangible costs are certain of the capital costs which, for taxable net income calculation purposes, are expensed or written off in the year of expenditures or at a specified rate over a number of years.

A distinction is made for tax purposes between **Canadian Exploration Expense**, **Canadian Development Expense**, and **Canadian Oil and Gas Property Expense**. All these expenses may be carried forward indefinitely. These expenses must be reduced by the amount of any incentive payments made by the Federal government for exploration or development.

(a) **Canadian Exploration Expense (CEE)** includes intangible costs of drilling exploratory wells, as well as geological and geophysical expenses and all dry wells. These costs may be written off at the rate of 100 percent by principal business corporations in the year in which the expenditure was made.

(b) **Canadian Development Expense (CDE)** includes intangible development drilling costs. Canadian Development Expense is written off at the rate of 30 percent per annum of the diminishing balance.

(c) **Canadian Oil and Gas Property Expense (COGPE)** includes the cost of purchasing any producing oil and gas reserves and any unproven P&NG properties. This expense is written off at the rate of 10 percent per annum of the diminishing balance.

Income Tax Rates

The tax rates used for an escalated case reflect the current position of the Federal and Provincial governments with respect to income taxes in Canada. A constant case will reflect the current tax rates held flat for the projection period. The following table provides the taxation rates for the current year and the final year of the transition period.

Resource and Processing Income

	Resource Income					Processing Income(1)				
	2008	**2009**	**2010**	**2011**	**2012**	**2008**	**2009**	**2010**	**2011**	**2012**
Net Federal Rate:	19.5	19.0	18.0	16.5	15.0	19.5	19.0	18.0	16.5	15.0
Provincial Rates:										
Alberta	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
British Columbia	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Manitoba	14.0/ 13.0	13.0	13.0	13.0	13.0	14.0/ 13.0	13.0	13.0	13.0	13.0
Newfoundland	14.0	14.0	14.0	14.0	14.0	5.0	5.0	5.0	5.0	5.0
Nova Scotia	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Ontario	14.0	14.0	14.0	14.0	14.0	12.0	12.0	12.0	12.0	12.0
Saskatchewan	13.0/ 12.0	12.0	12.0	12.0	12.0	10.0	10.0	10.0	10.0	10.0

(1) Manufacturing and processing.

Capital Taxes

A federal “Large Corporation Tax” of 0.175 percent is employed in Canada on capital in excess of $50 million. The capital tax is fully creditable against the existing corporate surtax which is currently 1.12 percent for all types of income. This report includes the cost of the corporate surtax but does not reflect the impact of the federal Large Corporation Tax.

Successor Rules

Successor rules may apply where there has been an acquisition by a corporation, in which case resource tax pools that are transferred to the purchaser will be streamed so that they will only be allowed as deductions against proceeds attributable to the resource properties acquired from the vendor. This report does not reflect the impact of Successor Rules.

Net Present Values

The estimates of the P&NG reserves and their respective net present values are summarized by property and by reserves category in the Discussion section of this report.

Detailed forecasts of production and net revenue for the various reserves categories are presented in Tables in the Summary and Discussion sections.

EXHIBIT 12.1 / 12.2

CERTIFICATIONS

I, James Cassina, certify that:

1. I have reviewed this annual report on Form 20-F of Eagleford Energy Inc.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the company as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the company and have;

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the company including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the company's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the company's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the company's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the company's internal control over financial reporting.

Date: April 23, 2012

By: /s/ James Cassina
James Cassina
Chief Executive and Financial Officer

EXHIBIT 13.1 / 13.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Eagleford Energy Inc. (the "Company") on Form 20-F for the year ended August 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, James Cassina, Chief Executive and Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that;

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

/s/ James Cassina
Name: James Cassina
Title: Chief Executive and Financial Officer
Date: April 23, 2012