EAGLEFORD ENERGY INC

FORM 51-101F1

STATEMENT OF RESERVES DATA AND OTHER OIL & GAS INFORMATION

FOR THE YEAR ENDED AUGUST 31, 2011

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GLOSSARY OF TERMS

Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
Oil and Natural Gas Liquids	
Bbl	Barrel
Mbbls	thousand 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) 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. Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
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	Hectares	0.405
Hectares	Acres	2.471

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.

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.

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.

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.

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 nonproducing.

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.

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.

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.

Levels of Certainty for Reported 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.

Remaining Recoverable Reserves are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.

Company Gross Reserves are the Company's working interest share of the remaining reserves, before deduction of any royalties.

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.

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.

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.

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.

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.

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.

Non-Associated Gas – an accumulation of natural gas in a reservoir where there is no crude oil.

Associated Gas – the gas cap overlying a crude oil accumulation in a reservoir.

Solution Gas – gas dissolved in crude oil.

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.

FORWARD-LOOKING STATEMENTS

This statement of Reserves Data and Other Oil and Gas Information ("**Statement of Reserves**") contains forward-looking information and forward-looking statements (collectively "**forward-looking statements**"). These forward-looking statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", and similar expressions. Such statements represent the Corporation's internal projections, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital expenditures, anticipated future debt levels and revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in the forward-looking statements. In addition, this Statement of Reserves may contain forward-looking statements attributed to third party industry sources. Eagleford believes that the expectations reflected in those forward-looking statements are reasonable; however, undue reliance should not be placed in these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur.

Forward-looking statements in this Statement of Reserves include, but are not limited to, statements with respect to:

- the performance characteristics of the Company's oil and natural gas properties;
- the Company's oil and natural gas production levels;
- the size of the Company's oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future development and exploration activities and the timing thereof;
- future land expiries;
- future liquidity and financial capacity;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of risk factors set forth below and elsewhere in this Statement of Reserves:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- general economic conditions in Canada and the United States;
- the ability of management to execute its business plan;
- risks and uncertainties involving geology of oil and gas deposits;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- risks inherent in marketing operations, including credit risk;
- the ability to enter into or renew leases;
- incorrect assessments of the value of acquisitions;
- potential delays or changes in plans with respect to exploration and development projects or capital expenditures;
- shut-ins of connected wells resulting from extreme weather conditions;
- insufficient storage or transportation capacity;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- geological, technical, drilling and processing problems; and

• changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry.

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

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Statement of Reserves are expressly qualified by this cautionary statement. Except as required by applicable securities law, Eagleford does not undertake any obligation to publicly update or revise any forward-looking statements.

PART 1
DATE OF STATEMENT

Item 1.1 **Relevant Dates:**

1.	Date of Statement:	December 15, 2011
2.	Effective Date of Statement:	August 31, 2011
3.	Preparation Date of Statement:	December 7, 2011

PART 2
DISCLOSURE OF RESERVES DATA

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, the Company's independent qualified reserves evaluator Sproule Associates Limited ("Sproule") prepared a report (the "Sproule Report") dated August 31, 2011 using current geological and engineering knowledge, techniques and computer software. It was prepared within the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta ("APEGGA"). The Sproule Report adheres in all material aspects to the "best practices" recommended in the Canadian Oil and Gas Evaluation Handbook ("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.

The Sproule Report evaluated 100% of Eagleford Energy Inc.'s ("Eagleford" or the "Company") natural gas reserves, as at August 31, 2011.

The tables below are summaries of the Company's natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of our natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Sproule Report is based on certain factual data supplied by the Company and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's natural gas property and contracts (except for certain information residing in the public domain) were supplied by the Company to Sproule and accepted without and further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted. The Company's interests covered by the Sproule Report are located in the Province of Alberta, Canada.

All monetary references contained in this Statement of Reserves Data and Other Oil and Gas Information are in Canadian dollars unless otherwise specified.

Item 2.1 **Reserves Data (Forecast Prices and Costs):**

1. Breakdown of Reserves ((Forecast Case):

NI 51-101 Summary of Oil and Gas Reserves As of August 31, 2011 Forecast Prices and Costs		
Reserves		
	Natural Gas (non-associated & associated)	
Reserves Category	**Gross (MMcf)**	**Net (MMcf)**
Proved		
Developed Producing	203	161
Total Proved	**203**	**161**
Probable	66	49
Total Proved Plus Probable	**269**	**211**

2. Net Present Value of Future Net Revenue (Forecast Case):

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 ($/BOE)**
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	
Proved						
Developed Producing	444	288	205	155	124	7.60
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**

Notes: Net Present Value of Future Net Revenue includes all resource income:
Sale of oil, gas, by-product reserves
Processing third party reserves
Other income
Unit Values are based on net reserve volumes

3. Additional Information Concerning Future Net Revenue (Forecast Case):

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 Abandon-ment/Other 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

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	Natural Gas (including associated by-products)*	205	7.60
Proved Plus Probable	Natural Gas (including associated by-products)*	243	6.93

*Includes corporate Capital GCA, if applicable
Unit values are based on net reserve volumes

Item 2.2 **Supplementary Disclosure (Constant Prices and Costs):**

Not Applicable

Item 2.3 **Reserves Disclosure Varies With Accounting:**

Not Applicable

Item 2.4 **Future Net Revenue Disclosure Varies With Accounting:**

Not Applicable

PART 3
PRICING ASSUMPTIONS

Item 3.1 **Constant Prices Used in Supplementary Estimates:**

Not Applicable

Item 3.2 **Forecasted Prices Used in Estimates:**

Forecast Prices (as determined by Sproule Associates Limited).

NI 51-101
Summary of Pricing and
Inflation Rate Assumptions
As of August 31, 2011
Forecast Prices and Costs

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40º API ($Cdn/bbl)	Cromer Medium 29.3º API ($Cdn/bbl)	Natural Gas (1) AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus F.O.B. 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	84.13	57.04	1.0	0.971
2011	90.28	87.42	84.42	3.55	93.46	78.92	2.0	1.012
Forecast								
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 at 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.

The weighted average historical natural gas price received by Eagleford for the year ended August 31, 2011 was $3.68/Mcf.

PART 4
RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 **Reserves Reconciliation**

NI 51-101 Reconciliation of Company Gross (1) Reserves (Before Royalty) By Principal Product Type As of August 31, 2011 Forecast Prices and Costs			
	Associated and Non-Associated Gas		
Factors	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**
August 31, 2010	213	69	282
Technical Revisions	9	(3)	6
Production	(19)	-	(19)
August 31, 2011	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.

PART 5
ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 **Undeveloped Reserves:**

1. Proved Undeveloped Reserves:

Not Applicable

2. Probable Undeveloped Reserves:

Not Applicable

Item 5.2 **Significant Factors or Uncertainties Affecting Reserves Data:**

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.

Item 5.3 Future Development Costs:

Not Applicable

PART 6
OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells:

1. Properties, Plants, Facilities and Installations

Properties:
All of the properties which the Company has an interest are located onshore in Canada and the United States.

Canada
At August 31, 2011 the Company has a 5.1975% working interest in a natural gas unit located in the Botha area Northwest, near the town of Manning, Alberta and a 0.5% overriding royalty in a natural gas well located in the Haynes area of Alberta, Canada.

United States
Matthews Lease, Zavala County, Texas

At August 31, 2011 the Company holds through its wholly owned subsidiary Dyami Energy Inc. ("Dyami Energy") a 75% working interest before payout which reduces to a 61.50% working interest after payout of $12,500,000 of production revenue and directly a 10% working interest before payout which reduces to a 7.50% working interest after payout of $15,000,000 of production revenue subject to the Farmout Agreement below.

The Matthews lease comprises approximately 2,629 gross acres of land in Zavala County, Texas.

The royalties payable under the Matthews lease are 25%.

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.

At August 31, 2011 the company holds through 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. Thereafter Dyami Energy's working interests range from 90% to 97%.

The royalties payable under the Murphy Lease are 25%.

Acreage:

The following table sets forth the developed acreage of the projects in which the Company holds an interest, on a gross and a net basis as of August 31, 2011. 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, Canada. Our developed acreage is as follows:

August 31	**2011**		**2010**		**2009**	
Alberta, Canada	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Leasehold Acreage-Developed	8,320	432.43	8,320	432.43	8,320	432.43

2. Producing and Non Producing Wells:

The following table sets forth the number of Eagleford's gross and net oil and gas wells producing and non-producing as of August 31, 2011. A gross well is a well in which the Company owns an interest. A net well represents the fractional interest the Company owns in gross wells. All of the Company's producing wells at August 31, 2011 were located in Alberta, Canada.

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

Item 6.2 Properties With No Attributed Reserves:

At August 31, 2011 the Company has an interest in two leases covering approximately 5,266 gross acres of land in Zavala County, Texas, United States where no reserves have been assigned.

Matthews Lease, Zavala County, Texas

At August 31, 2011 the Company holds through its wholly owned subsidiary Dyami Energy a 75% working interest before payout which reduces to a 61.50% working interest after payout of $12,500,000 of production revenue and holds directly a 10% working interest before payout which reduces to a 7.50% working interest after payout of $15,000,000 of production revenue. The Matthews lease comprises approximately 2,629 gross acres of land in Zavala County, Texas. The royalties payable under the Matthews lease are 25%.

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.

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

Murphy Lease, Zavala County, Texas

At August 31, 2011 the company holds through 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. Thereafter Dyami Energy's working interests range from 90% to 97%. The royalties payable under the Murphy Lease are 25%.

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.

Acreage:

The following table sets forth the undeveloped acreage of the projects in which the Company holds an interest, on a gross and a net basis as of August 31, 2011. Our undeveloped acreage is as follows:

August 31	**2011**		**2010**		**2009**	
Texas, USA	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Leasehold Acreage-Undeveloped	5,266	4,793	5,266	4,872	Nil	Nil

Item 6.2.1 <u>Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves</u>

A part of the Company's oil and gas development program, significant capital expenditures are required to maintain the Company's Texas Leases in good standing. The amount expended on future exploration and development on these leases is dependent on the nature of those opportunities evaluated by the Company. Any additional expenditures on the leases will be required to be funded by additional share capital issuances or debt issued by the Company, or by other means. At this time, no assurances can be made that the Company's Texas Leases will economically produce commercial quantities of oil and gas.

Item 6.3 <u>Forward Contracts:</u>

The Company has no forward contracts.

Item 6.4 <u>Additional Information Concerning Abandonment and Reclamation Costs:</u>

The Company bases its estimates for costs of abandonment and reclamation of surface leases and wells, net of estimated salvage value, on previous experience with similar well site locations and terrain, estimates obtained from area operators and various regulatory abandonment guidelines and requirements. The Company believes that its range of estimates of per well for abandonment and reclamation costs are reasonable and applicable to its wells. The Company's independent qualified reserves evaluator has also estimated similar costs in deriving the Company's estimate of future net revenue. The following table accounts for costs for only the wells which were evaluated by Sproule and have not included other shut-in, suspended or uncompleted wells in which the Company has an interest.

Year	Proved		Proved plus Probable	
	Undiscounted	Discounted at 10%	Undiscounted	Discounted at 10%
	$M	$M	$M	$M
2030	5	0	1	6

Ultimately all wells in which the Company has an interest will require abandonment and reclamation. The total estimated undiscounted cash flows adjusted for inflation required to settle the Company's 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. The Company estimates that the settlement of these obligations will occur between 2022 and 2030.

The Company does not expect to pay abandonment and reclamation costs over the next 3 fiscal years.

Item 6.5 **<u>Tax Horizon:</u>**

The Company has non-capital losses of $$1,349,189 at August 31, 2011 and does not anticipate paying significant income taxes in the near term.

Item 6.6 **<u>Costs Incurred:</u>**

For the year ended August 31, 2011 the Company incurred the following costs:

	August 31, 2011
Developed - Canada	
Net book value at September 1, 2010	$ 314,000
Change in asset retirement obligation estimate	1,600
Depletion	(17,905)
Impairment	(54,695)
Total developed, Alberta Canada	243,000
Undeveloped - USA	
Net book value September 1, 2010	5,695,290
Exploration expenditures	3,158,688
Asset retirement obligation	44,150
Total undeveloped, Texas, USA	$8,898,128
Total developed and undeveloped	**$9,141,128**

Item 6.7 **<u>Exploration and Development Activities:</u>**

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.

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 and based on those results and new industry practices the Company is formulating a detailed frac design and completion plan for the Dyami/Matthews #1 H well.

On March 29, 2011 the Company 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. Subsequently, the Company completed a nitrified acid injection operation and the heavy oil well has been placed on production testing.

On January 20, 2011 the Company 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 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 the Company is formulating a completion program.

On July 30, 2011 the Company spud its 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. The Company is currently waiting for its core analysis results to formulate a completion plan.

Dyami Energy is required to drill a well every six months in order maintain the Matthews and Murphy Leases in Zavala County, Texas.

Item 6.8 **<u>Production Estimates:</u>**

The following table indicates the volume of production estimated for the first year reflected in the estimates of gross proved reserves and gross probable reserves based on forecast prices and costs.

Property	**Associated and Non-Associated Gas (MMcf) Proved**	**Associated and Non-Associated Gas (MMcf) Probable**
Botha, Alberta, Canada	18	1

Item 6.9 **<u>Production History:</u>**

1. The following table sets forth certain information in respect of production, product prices received, production costs and netbacks received by the Company for each quarter of fiscal 2011.

Production History	**Fiscal 2011**			
	August 31	**May 31**	**February 28**	**November 30**
Average Daily Production				
Natural gas (Mcf per day)	54	52	55	53
Average Commodity Prices				
Natural gas ($/Mcf)	$3.62	$3.76	$3.82	$3.53
Royalties				
Natural gas ($/Mcf)	$0.71	$0.89	$0.81	$0.64
Production Costs				
Natural gas ($/Mcf)	$0.52	$3.43	$3.38	$3.42
Netback by Product				
Natural gas ($/Mcf)	$2.39	$(0.56)	$(0.37)	$(0.53)

2. The following table indicates the Company's total production for fiscal 2011 from its core property.

Property	**Associated and Non-Associated Gas (MMcf)**
Botha, Alberta	19