



FORM 51-101F1

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

**FOR THE YEAR ENDED
AUGUST 31, 2014**

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	28.174
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. For additional risk factors, please see the Company’s Annual Information Form filed on Form 20F.

PART 1
DATE OF STATEMENT

Item 1.1 Relevant Dates:

- | | | |
|----|--------------------------------|-------------------|
| 1. | Date of Statement: | December 29, 2014 |
| 2. | Effective Date of Statement: | August 31, 2014 |
| 3. | Preparation Date of Statement: | December 18, 2014 |

PART 2
DISCLOSURE OF RESERVES DATA

2014 and 2013

The Company has a 0.5% non-convertible gross overriding royalty in a natural gas well located in the Haynes area of Alberta and a 5.1975% interest in a natural gas unit located in the Botha area of Alberta, Canada both of which are carried on the consolidated statement of financial position at nil as at August 31, 2014.

For the year ended August 31, 2013, the Company recorded an impairment loss of the full carrying costs of \$168,954 for its Botha, Alberta property as a result of no recordable reserves and no discernable future net revenue being assigned by the operator and independent reserves evaluator. During the quarter ended August 31, 2013, the remaining wells in the Botha gas unit were shut in.

As the Company had no recordable reserves or discernable future net revenue at August 31, 2014 and 2013 for its Botha, Alberta Property, the Company did not retain an independent reserves evaluator and accordingly there is no National Instrument Form 51-101F2 attached to this filing.

For the years ended August 31, 2014 and 2013 the Company had not booked reserves for its Texas assets.

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):

Not Applicable as the Company has no recordable reserves and no discernable future net revenue.

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

Not Applicable as the Company has no recordable reserves and no discernable future net revenue.

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

Not Applicable as the Company has no recordable reserves and no discernable future net revenue.

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:

Not Applicable as the Company has no recordable reserves and no discernable future net revenue.

The weighted average historical natural gas price received by Eagleford for the year ended August 31, 2014 was \$4.34/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, 2014			
Forecast Prices and Costs			
Associated and Non-Associated Gas			
Factors	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
August 31, 2014	Nil	Nil	Nil
Technical Revisions	Nil	Nil	Nil
Production	Nil	Nil	Nil
August 31, 2013	Nil	Nil	Nil

(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, 2014 the Company had 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 both carried on the statement of financial position at nil. For the year ended August 31, 2013 the Company recorded an impairment loss of the full carrying amount of \$168,954 for its Botha, Alberta property as a result of no recordable reserves and no discernable future net revenue net revenue assigned by the operator and independent reserves evaluator. During the quarter ended August 31, 2013, the remaining wells in the Botha gas unit were shut in.

United States

The Company's exploration and evaluation assets are located in Texas, USA. As at August 31, 2014 an impairment of \$1,675,749 was recorded on the Murphy Lease (\$1,315,276 net of foreign currency translation gain of \$301,884 and write off of decommissioning obligations of \$58,589) (August 31, 2013: \$2,690,568). Included in the above additions for the year ended August 31, 2014, the Company capitalized borrowing costs interest of \$Nil to exploration and evaluation assets (August 31, 2013: \$240,092).

Matthews Lease, Zavala County, Texas

During the year ended August 31, 2013, the Company, Dyami Energy and OGR Energy Corporation, the Lessees, were litigating a dispute with the Lessors of the Matthew's property. During the last quarter of fiscal year August 2013, the Company and the Lessors agreed to resolve the litigation and continue with the development of the Matthew's property. In order to comply with certain State legal requirements, it was deemed necessary by the Lessors counsel to continue with the development through a newly executed lease document and the Company formed, Zavala Inc. a new wholly owned subsidiary to execute the new lease. The new lease was signed effective September 1, 2013 and the first of two payments of US\$150,000 were paid to the Lessors upon signing the new lease as required initial pre-payment of anticipated production royalties along with a continuing development obligation under the lease to complete the previously drilled Matthews #1H horizontal well or drill a new well on the Matthews property no later than March 30, 2014. On September 1, 2013, the Matthews lease was renewed by the Company through Zavala Inc. and based on the concept of faithful representation under IAS 8, the carrying value of the Matthew's lease by Dyami Energy was considered to be the value for Zavala Inc. as this arrangement is simply a reorganization in substance.

On December 3, 2013, (amended January 21, 2014) the Company entered into a Joint Development Agreement with Stratex Oil and Gas Holdings, Inc. ("Stratex") (the "Stratex JDA") to further develop the Matthews Lease. Under the terms of the Stratex JDA, Stratex will act as operator and upon Stratex delivering i) US\$150,000 to the lessors of the Matthews Lease on behalf of Zavala Inc., ii) delivering US \$150,000 to the Company; and iii) commencing a hydraulic fracture of the Matthews #1H not later than March 31, 2014 Stratex earned a 66.67% working interest before payout (50% working interest after payout) in the Matthews #1H well and a 50% working interest in the 2,629 acre Matthews Lease (see Note 17 to the consolidated financial statements).

Through Zavala Inc., the Company holds a 50% working interest in the 2,629 acre Matthews Lease (33.33% working interest before payout and 50% working interest after payout in the Matthews #1H well). The Matthews Lease had a primary term extended to March 31, 2014 (the "Primary Term") while each lease year ends August 31. Prior to the expiration of the Primary Term, a hydraulic fracturing of the Matthews #1H well was completed and thereafter the lease is maintained through a guaranteed minimum royalty payment of \$323.30 per acre and beginning in the second lease year and continuing thereafter for each succeeding lease year drill at least 2 wells per lease year. The royalties payable under the Matthews Lease are 25%.

On April 11, 2014, the Company entered into a further Joint Development Agreement (“JDA2”) with Stratex and Quadrant Resources LLC, (“Quadrant”) for the development of the San Miguel formation on the Matthews Lease. Pursuant to the terms of the JDA2, upon satisfaction of certain conditions including the Phase 1 Work Program and the cash consideration described below, Quadrant can earn an undivided 66.67% before payout and a 50% working interest after payout to the base of the San Miguel formation of the Matthews Lease by i) drilling 3 new wells and reworking 5 wells at its sole cost and expense by June 30, 2015 (the “Phase I Work Program”); ii) deliver US\$100,000 to the Company upon execution of the JDA2 (paid); and iii) deliver US\$65,000 to the Company on each of July 8, 2014 (paid); October 6, 2014, January 5, 2015 and April 6, 2015. At August 31, 2014 the Company recorded the payments received from Quadrant of US\$165,000 (CDN \$177,804) as deferred revenue on the Consolidated Statement of Financial Position until the conveyance of the earned interest at which time this amount will be reclassified and offset against exploration and evaluation assets.

Murphy Lease, Zavala County, Texas

Subsequent to September 1, 2013 and the continuing development of the Matthews lease, Dyami Energy continued its development efforts with the Murphy lease. A tentative joint venture agreement with Stratex was reached but did not materialize and efforts to develop the Murphy lease were not successful. The Company had solicited lenders and investors in an attempt to obtain debt/equity financings as a means to improve Dyami Energy’s financial situation. Despite the Company’s attempts, these efforts were unsuccessful and management determined that it could no longer fund the Murphy operations, hence the lease was considered impaired and an impairment loss was recorded by Dyami Energy during the third quarter (see Note 16).

On March 6, 2014, the Company filed a Certificate of Termination of a Domestic Entity with the Secretary of State, Texas for its wholly-owned subsidiary Dyami Energy and effective April 3, 2014, Dyami Energy was dissolved. All prior obligations with respect to the Matthew’s and Murphy’s lease on the books of Dyami Energy prior to its dissolution were recorded by the Company.

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, 2014, 2013 and 2012. 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 and on the basis of stated lease terms in conjunction with the Texas Rail Road Commission. Our developed acreage is located in Alberta, Canada. Our undeveloped acreage is located in Zavala County, Texas.

August 31,	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Developed Acreage, Canada	8,320	432	8,320	432	8,320	432
Undeveloped Acreage, USA	2,629	1,314.5	5,266	4,793	5,266	4,793

2. Producing and Non 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, 2014, 2013 and 201. 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	2014		2013		2012	
Alberta, Canada	Gross	Net	Gross	Net	Gross	Net
Natural Gas Wells-Producing	3.0	.05175	3.0	.05175	3.0	.05175

Natural Gas Wells-Non Producing	9.0	.05175	9.0	.05175	6.0	.31005
Texas, USA						
Oil Wells – Non Producing	3.0	.4444	7.0	.66666	7.0	.66666

Item 6.2 Properties With No Attributed Reserves:

At August 31, 2014 the Company had a 5.1975% working interest in a natural gas unit located in the Botha area Northwest, near the town of Manning, Alberta. For the year ended August 31, 2013 the Company recorded an impairment loss of the full carrying costs of its Botha, Alberta property as a result of no recordable reserves and no discernable future net revenue being assigned by the operator and independent reserves evaluator. During the quarter ended August 31, 2013, the remaining wells in the Botha gas unit were shut in.

Acreage:

August 31,	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Developed Acreage, Canada	8,320	432	8,320	432	8,320	432

At August 31, 2014 the Company has an interest in a lease covering approximately 2,469 gross acres of land in Zavala County, Texas, United States where no reserves have been assigned (See Item 6.1 above).

Acreage:

The following table sets forth the acreage of the Zavala County, Texas projects in which the Company holds an interest, on a gross and a net basis as of August 31, 2014, 2013 and 2012:

August 31	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Texas, USA						
Leasehold Acreage-Undeveloped	2,629	1,314.5	5,266	4,793	5,266	4,793

Non Producing Wells:

The following table sets forth the number of Eagleford’s gross and net non-producing oil and gas wells in Texas, USA as of August 31, 2014, 2013 and 2012. 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.

August 31	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Alberta, Canada						
Natural Gas Wells-Non Producing	9.0	.05175	9.0	.05175	6.0	.31005

August 31	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Texas, USA						
Oil Wells – Non Producing	3.0	.4444	7.0	6.60	7.0	6.60

Item 6.2.1 Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

A part of the Company's oil and gas development program, significant capital expenditures are required to develop and 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 or that the Company will obtain the necessary financing to fully develop its Leases.

Item 6.3 Forward Contracts:

The Company has no forward contracts.

Item 6.4 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. Ultimately all wells in which the Company has an interest will require abandonment and reclamation.

The Company's abandonment and reclamation obligations result from its ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company has estimated the net present value of these obligations to be \$47,543 at August 31, 2014 based on an undiscounted total future liability of \$60,629. These payments are expected to be incurred between fiscal 2015 and 2031.

Item 6.5 Tax Horizon:

The Company has unused capital losses in the amount of approximately \$195,852 which may be carried forward indefinitely to offset future capital gains, and unused non capital losses in the amount of approximately \$3,335,413 available to reduce income in future years and does not anticipate paying significant income taxes in the near term.

Item 6.6 Costs Incurred:

For the year ended August 31, 2014, the Company incurred the following costs:

Exploration and evaluation assets	
Balance August 31, 2013	\$6,535,278
Additions, net	113,578
Change in decommissioning obligation estimates	7,225
Disposal of decommissioning obligations, Matthews Lease JDA	(26,426)
Impairment on dissolution of subsidiary	(1,675,749)
Foreign exchange	82,686
Balance August 31, 2014	<u>\$5,036,592</u>

The Company's exploration and evaluation assets are located in Texas, USA. As at August 31, 2014 an impairment of \$1,675,749 was recorded on the Murphy Lease upon the dissolution of the Company's subsidiary Dyami Energy Inc., see Note 16 to the Consolidated Financial Statements.

Item 6.7 Exploration and Development Activities:

During the fiscal year ended August 31, 2014, the Company drilled no exploratory wells on its lease located in Zavala County, Texas USA. During fiscal 2014, the Company entered into a Joint Development Agreement with Stratex whereby Stratex completed the hydraulic fracture of the Matthews #1H well and placed the well on production testing.

The following table sets forth the number of Eagleford's gross and net exploratory wells drilled in Texas, USA during the year ended August 31, 2014, 2013 and 2012. 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

August 31	2014		2013		2012	
Texas, USA	Gross	Net	Gross	Net	Gross	Net
Oil Wells – Non Producing	-	-	-	-	3.0	2.70

During fiscal 2012, the Company drilled the Dyami/Murphy #4 well, the Dyami/Murphy #3 and the Dyami/Matthews #2 well.

Item 6.8 Production Estimates:

Not Applicable as the Company has no recordable reserves and no discernable future net revenue.

Item 6.9 Production History:

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 2014.

Production History	Fiscal 2014			
	August 31	May 31	February 28	November 30
Average Daily Production				
Natural gas (Mcf per day)	53	59	41	54
Average Commodity Prices				
Natural gas (\$/Mcf)	\$4.34	\$5.92	\$3.94	\$3.04
Royalties				
Natural gas (\$/Mcf)	\$0.96	\$1.56	\$0.88	\$0.27
Production Costs				
Natural gas (\$/Mcf)	\$0.89	\$0.86	\$1.37	\$0.40
Netback by Product				
Natural gas (\$/Mcf)	\$2.49	\$3.50	\$1.69	\$2.37

2. The following table indicates the Company's total production for fiscal 2014 from its Botha, Alberta property.

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



FORM 51-101F3

**REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION**

Management of Eagleford Energy Corp. ("the Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at August 31, 2014, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The board of directors of the Company has

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation and in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

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

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

“JAMES CASSINA”

James Cassina, President, Secretary and Director

“MILTON KLYMAN”

Milton Klyman, Director

“COLIN MCNEIL”

Colin McNeil, Director

December 29, 2014