VISION GROWTH INCOME

2014 Financial Report

EAGLE ENERGY™
TRUST

Management's Discussion and Analysis

March 19, 2015

This Management's Discussion and Analysis ("**MD&A**") of financial condition and results of operations for Eagle Energy Trust (the "**Trust**" or "**Eagle**"), dated March 19, 2015, should be read in conjunction with the Trust's audited consolidated financial statements and accompanying notes for the year ended December 31, 2014 and the Trust's Annual Information Form ("**AIF**"), which are available online under the Trust's issuer profile at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

The Trust's audited annual consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**"). Items included in the financial statements of each of the Trust's subsidiaries are measured using the currency of the primary economic environment in which the entity operates ("**the functional currency**"). The audited annual consolidated financial statements are presented in Canadian dollars, which is the functional and presentation currency of the Trust.

Figures within this MD&A are presented in Canadian dollars unless otherwise indicated.

The foreign exchange rate at December 31, 2014 was $US 1 equal to $CA 1.16 (December 31, 2013 - $US 1 equal to $CA 1.06), and the average foreign exchange rate for the year ended December 31, 2014 was $US 1 equal to $CA 1.10 (for the year ended December 31, 2013 - $US 1 equal to $CA 1.03).

Throughout this MD&A, Eagle Energy Trust and its subsidiaries are collectively referred to as "the Trust" or "Eagle" for purposes of convenience. In addition, references to the results of operations refer to operations of the Trust's subsidiaries in the U.S. and in Canada.

This MD&A contains information that is forward looking. Investors should read the "Note about forward looking statements" section at the end of this MD&A. This MD&A refers to non-IFRS financial measures. See section titled "Non-IFRS financial measures", below.

Other financial data has been prepared in accordance with IFRS.

Overview and History of the Trust

Eagle Energy Trust is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The Trust's activities are restricted to owning property (other than real property or interests in real property), and it does not carry on business. The Trust's stated business strategy is to invest in its operating subsidiaries to fund the acquisition of petroleum reserves and production with unexploited low risk development potential and to pay out a portion of available cash to unitholders of the Trust on a monthly basis. The Trust was created to provide investors with a sustainable business model while delivering moderate growth in production and overall growth through accretive acquisitions.

The Trust was formed on July 20, 2010, but did not commence active operations until November 24, 2010, the date of its initial public offering. During November and December 2010, the Trust raised $149.5 million, at an offering price of $10.00 per trust unit, through an initial public offering. Concurrently, through its wholly-owned subsidiary, the Trust acquired an average 73% interest in the Salt Flat Field, a light oil property located near the town of Luling in south central Texas, for $127.1 million.

In May 2012, the Trust closed a bought deal financing, issuing 8,680,000 trust units at a price of $11.00 per trust unit, for total proceeds of $95.5 million, including the proceeds from the exercise of the over-allotment option. Concurrent with closing this financing, Eagle acquired 92.5% of the seller's 99% interest in certain Permian Basin properties ("Permian"), located near Midland, Texas. After the closing, Eagle also acquired all of another party's 1% interest in the same properties.

On April 22, 2013, the Trust acquired the remaining 7.5% of the seller's interest in the Permian properties.

On November 25, 2013, the Trust acquired an approximate 90% working interest in certain producing properties in Hardeman County, Texas and subsequently acquired an additional 66% working interest in certain producing properties in Hardeman County, Texas and Greer, Harmon and Jackson counties, Oklahoma on February 27, 2014.

On June 16, 2014, the Trust's subsidiaries completed an internal reorganization pursuant to which the Trust's new indirect U.S. subsidiary, Eagle Hydrocarbons Inc., acquired all of the assets and assumed all of the obligations of Eagle Energy Acquisitions LP and its general partner, Eagle Hydrocarbons LLC. Management and the directors of Eagle Hydrocarbons Inc. are the same individuals as management and the directors of Eagle Hydrocarbons LLC. Eagle Energy Acquisitions LP and Eagle Hydrocarbons LLC were subsequently dissolved at the end of 2014. On August 29, 2014, the Trust disposed of its entire working interest in its Permian properties in Martin County and used the net proceeds to fully retire its outstanding debt, as well as have cash on hand.

At a special unitholders' meeting held on December 15, 2014, the Trust's unitholders approved a resolution to amend the investment restrictions in the Trust Indenture and to make certain corollary amendments, which enabled the Trust to invest, indirectly through a subsidiary, in energy assets in Canada. On December 18, 2014, a newly formed subsidiary of the Trust, Eagle Energy Canada Inc., acquired a 50% non-operated working interest in the Dixonville Montney "C" oil pool, located in the Peace River region of Alberta, Canada, for $100.9 million, which includes preliminary closing adjustments of $0.9 million.

DRIP and NCIB

Commencing with the distribution paid on October 23, 2014, the Trust suspended the Premium Distribution™ component of its Distribution Reinvestment Plan ("DRIP"). Commencing with the distribution paid on February 23, 2015, the Trust suspended the regular DRIP program. For the one year period commencing on January 21, 2015, the Trust instituted a normal course issuer bid ("NCIB").

Highlights for the year ended December 31, 2014

Management's 2014 objective was to reduce the overall decline rate of Eagle's assets and the capital necessary to maintain production levels. Achieving this objective increased Eagle's free cash flow and improved the sustainability of its business.

Eagle achieved the following results in 2014:

- Sold its Permian asset (Texas) in August 2014 while commodity prices were strong, and redeployed roughly two-thirds of the sale proceeds during the downturn in commodity prices to acquire the Dixonville asset (Alberta) in December 2014 for $100.9 million.
- These transactions resulted in net proceeds of $50 million (used to retire debt), an increase to corporate production of 250 boe/d and an increase to free cash flow of $6.6 million.
- Continued to manage Eagle in a financially prudent manner, with 2014 year end debt to trailing cash flow of 1.1x and $34.7 million ($US 29.3 million) of credit available on the Trust's existing facility.
- Increased proved developed producing reserves volumes by 88% and the net present value discounted at 10% ("**PV10**") by 29%.
- Despite a substantial decline in year over year benchmark oil prices, achieved a 4% increase in total proved reserve volumes and a 2.4% increase in total proved reserves value (PV10).
- Achieved a total proved reserve replacement ratio of 145% and total proved plus probable reserve replacement ratio of 265%.
- Reported average working interest sales volumes of 2,782 barrels of oil equivalent per day ("**boe/d**") (85% oil, 8% natural gas liquids ("NGLs"), 7% natural gas). Current working interest production approximates 3,000 boe/d (97% oil).
- 85% of Eagle's 2014 production was oil and Eagle realized an average oil price of $100.99 per barrel, while the WTI benchmark averaged $US 93.00.
- Reported funds flow from operations of $34.0 million ($33.34 per boe or $1.01 per unit), notwithstanding the August 2014 disposition of the Permian assets.
- Maintained 2014 unitholder distributions at $0.0875 per unit per month from November 2010 to November 2014, then took action to protect its balance sheet in light of current and expected decrease in commodity prices by lowering its monthly distribution to $0.03.

Acquisition in December 2014

On December 18, 2014, a newly formed Canadian subsidiary of the Trust closed the acquisition of a 50% non-operated working interest in producing properties near the town of Dixonville, in the Peace River area of Alberta, for $100.9 million. Through the acquisition of this premier, long-life, oil producing water-flood property, Eagle acquired interests in 112 (56 net) producing wells, 82 (41 net) injection wells and associated facilities, gathering systems and pipelines. With less than 10% average annual decline, stable production base and low sustaining capital requirement, the Dixonville asset substantially reduced Eagle's total corporate sustaining capital requirements and dropped its corporate decline rate from approximately 30% to under 20%. The acquired working interest production at the date of the acquisition was approximately 1,250 boe per day for a purchase price metric of approximately $80,000 per flowing boe/d. The effective date of the acquisition was January 1, 2015.

This acquisition was funded with $55 million of the Trust's available cash and the balance from its existing credit facility. Concurrent with the closing of the acquisition, Eagle's credit facility was expanded to $US 70 million. On February 11, 2015, the credit facility was further expanded to $US 95 million. Amounts drawn on the credit facility can be denominated in US or Canadian dollars and provide Eagle with a funding source to grow through accretive opportunities that become available.

2015 Budget and Outlook

This outlook section is intended to provide unitholders with information about Eagle's expectations as at the date hereof for production and capital expenditures for 2015. Readers are cautioned that the information may not be appropriate for any other purpose. This information constitutes forward-looking information. Readers should note the assumptions, risks and discussions under "Note about forward-looking statements" at the end of this MD&A.

There have been no changes to Eagle's 2015 average production forecast of 2,950 to 3,150 boe/d on a $13.7 million capital budget ($US 9.9 million for its operations in the United States and $1.4 million for its operations in Canada), as originally disclosed in its February 12, 2015 news release.

Eagle's 2015 capital and operating budget is designed to minimize the capital spend necessary to sustain production levels, and then add a designated component of growth-focused capital. 2015 is expected to be a year of volatile commodity prices and Eagle's budget has been designed to reflect these circumstances.

The 2015 capital budget of $13.7 million ($US 9.9 million in the US and $1.4 million in Canada), consists of the following:

- Salt Flat, Texas
  - 3 (3.0 net) horizontal oil wells
  - Seismic processing, pump changes
- Hardeman, Texas and Oklahoma
  - 3 (3.0 net) vertical wells
  - 1 (1.0 net) salt water disposal well
  - Facilities and seismic capital
- Dixonville, Alberta (non-operated)
  - Maintenance capital on waterflood

Eagle's 2015 budget in Canada ($1.4 million) will be limited to maintenance capital at Dixonville. For its U.S. operations, Eagle's 2015 budget ($US 9.9 million) continues to focus on asset development in Texas and Oklahoma and delivering Eagle's commitment of sustainability, both at Salt Flat and at Hardeman. Eagle is evaluating seismic data from its 2014 seismic programs at Salt Flat and at Hardeman. The opportunity at Salt Flat is to better understand the faulting system in the field, and to identify reserves that have not been accessed by Eagle's existing wells and infrastructure. Eagle's focus at the Hardeman property is to continue to identify and delineate Chappell formation locations and to carry on from its successful 2014 drilling program in the area.

Eagle's 2015 guidance for its capital budget, production, operating costs and funds flow from operations is as follows:

	2015 Guidance	Notes
Capital Budget	$13.7 mm	1
Working Interest Production	2,950 to 3,150 boe/d	2
Operating Costs per month	$1.8 to $2.0 mm	3
Funds Flow from Operations	$29.5 mm	4
Debt to Trailing Cash Flow	1.2x	

Notes:

(1) The 2015 capital budget of $13.7 million consists of $US 9.9 million for Eagle's operations in the United States and $1.4 million for Eagle's operations in Canada. Based on a $US 60.00 WTI oil price, the 2015 capital budget is expected to deliver a distribution of $0.03 per unit per month ($0.36 per unit annualized) and a corporate payout ratio of 88%.

(2) 2015 production forecast consists of 97% oil, 1% natural gas liquids ("NGLs") and 2% gas.

(3) 2015 forecast operating costs result in field netbacks (excluding hedges) of approximately $26.41 per boe at $US 60.00 WTI.

(4) Funds flow from operations in 2015 is approximately $29.5 million based on the following assumptions:

a. Average working interest production of 3,050 boe/d (the mid-point of the guidance range);

b. Pricing at $US 60.00 per barrel WTI oil, $US 3.00 per Mcf NYMEX gas and $US 21.00 per barrel of NGL (NGL price is calculated as 35% of the WTI price);

c. Differential to WTI is a $US 6.15 discount per barrel in Salt Flat, a $US 2.70 discount per barrel in Hardeman and a $CA 15.00 discount per barrel in Dixonville;

d. Average operating costs of $1.9 million per month ($US 0.9 million per month for Eagle's operations in the United States and $0.7 million per month for Eagle's operations in Canada) being the mid-point of the guidance range; and

e. Foreign exchange rate of $US 1.00 equal to $CA 1.25.

A table showing the sensitivity of Eagle's funds flow to changes in production, exchange rates and commodity pricing is set out below under the heading "2015 Sensitivities".

Calculations regarding Eagle's distributions

Eagle calculates its payout ratios and financial strength as follows:

Payout Ratios (as a percentage of cash flow)	**2015 Guidance**	**Notes**
Basic Payout Ratio	42%	1
Plus: Capital Expenditures	46%	
Equals: Corporate Payout Ratio	88%	2
Financial Strength		
Debt to Trailing Cash Flow	1.2x	

Notes:

(1) Eagle calculates its Basic Payout Ratio as follows:

$$\frac{\text{Unitholder Distributions}}{\text{Funds Flow from Operations}} = \text{Basic Payout Ratio}$$

(2) Eagle calculates the Corporate Payout Ratio as follows:

$$\frac{\text{Capital Expenditures + Unitholder Distributions}}{\text{Funds Flow from Operations}} = \text{Corporate Payout Ratio}$$

A table showing the sensitivity of Eagle's Corporate Payout Ratio to changes in production, exchange rates and commodity pricing is set out below under the heading "2015 Sensitivities".

Underlying asset quality benchmarks

Oil and Gas Fundamentals	2015 Guidance	Notes
Oil Weighting	97 %	
Gas Weighting (@ 6 Mcf:1 bbl)	2 %	
NGL Weighting	1 %	
Operating costs per month	$1.8 to $2.0 million	1
Field Netbacks per boe	$26.41	2
% Hedged	36 %	3

Notes:

(1) Operating costs are stated on a per month basis rather than per boe due to the mostly fixed nature of the costs.

(2) Assumes average operating costs of $1.9 million per month (the mid-point of the guidance range) at a $US 60.00 WTI price and excludes hedges.

(3) Hedging supports sustainability in a volatile commodity price environment. For the first half of 2015, 1,600 barrels of oil per day is hedged at an average price of $US 90.00. For the second half of 2015, 590 barrels of oil per day are hedged at an average price of $US 87.00.

2015 Sensitivities

The following tables show the sensitivity of Eagle's funds flow, corporate payout ratio and net debt to cash flow to changes in commodity price, exchange rates and production:

Sensitivity to Commodity Price

	2015 Average WTI		
	$US 50 (FX 1.30)(5)	$US 60 (FX 1.25)(5)	$US 70 (FX 1.20)(5)
Cash Flow	$28.2	$29.5	$31.3
Corporate Payout Ratio	95%	88%	82%
Leverage	1.3x	1.2x	1.0x

Sensitivity to Production

	2015 Average Production (boe/d)		
	2,950	3,050	3,150
Cash Flow	$28.8	$29.5	$30.8
Corporate Payout Ratio	91%	88%	85%
Leverage	1.2x	1.2x	1.1x

Assumptions:

(1) Annual distributions are $0.36 per unit.

(2) No new equity issued.

(3) Operating costs of $1.9 million per month (the mid-point of the guidance range).

(4) Differential to WTI held constant.

(5) The foreign exchange rate is assumed to be as follows:

- At $US 50.00 WTI - $US 1.00 equal to $CA 1.30.
- At $US 60.00 WTI - $US 1.00 equal to $CA 1.25.
- At $US 70.00 WTI - $US 1.00 equal to $CA 1.20.

Sensitivities

The Trust's results and ability to generate sufficient amounts of cash to fund ongoing operations are affected by external market factors such as fluctuations in the prices of crude oil and natural gas, as well as movements in foreign-exchange rates and interest rates. Changes in production also affect funds flow. Sensitivities to these factors are summarized below.

	Quarterly impact on ➔	**Funds flow from operations ($000's)**	**Funds flow from operations / unit (1)**
Gas price (2)	+ USD $0.10/Mcf Henry HUB	8	0.00
Oil price (2)	+ USD $1.00/bbl WTI	206	0.01
Gas production	+1,000 Mcf/d	223	0.01
Oil production	+100 bbls/d	391	0.01
Currency (2)	+CDN weaken by $0.01	(122)	(0.00)
Interest Rate	+1%	(144)	(0.00)

Notes:

(1) Per unit figures are based on 33,675,603 weighted average basic units outstanding for the year ended December 31, 2014.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate of 2,782 boe/d.

Operations update

The disposition of the Permian properties in Martin County, Texas and the acquisition of the Dixonville properties in Alberta significantly changed the nature of Eagle's asset base. Forecast corporate declines have dropped from approximately 30% to under 20%, with the result being a significant reduction in required sustaining capital. As commodity prices recover, the percentage of free cash flow realized by the Trust will increase.

Eagle is well positioned to achieve full year 2015 production targets of 2,950 to 3,150 boe/d. Eagle will continue to focus on operational efficiencies and capital discipline during 2015 that lead to cost reductions.

At its Hardeman properties, Eagle has implemented a number of enhancements that have resulted in production gains. Eagle is continuing its efforts to lower operating expenses, by drilling a saltwater disposal well in the southern Hardeman operating area and installing electrical infrastructure for additional cost improvements. During the fourth quarter 2014, Eagle executed a successful two-well oil drilling program, validating its development plans for the area. Eagle is undertaking an extensive geological and geophysical review of the property in order to identify and quantify future drilling opportunities in addition to the three wells included in Eagle's 2015 capital budget.

At Salt Flat, Eagle drilled two new wells, side-tracked one existing well and installed eight horizontal pumps in existing wells to increase oil production. This work resulted in Eagle's best capital efficiency to date in the Salt Flat field. Eagle completed its planned 3-D seismic program and is currently evaluating the resulting seismic data, which is expected to optimize future drill locations in addition to the three wells already included in the 2015 capital budget and potentially identify lower zones to recover additional reserves. A combination of new wellbores and sidetracks of existing wellbores could be used to target the lower benches.

Prior to the sale of its Permian properties, Eagle drilled two new wells and recompleted eight wells. Eagle sold this property effective July 1, 2014.

On December 18, 2014, Eagle acquired a 50% non-operated working interest in the Dixonville property, located near Peace River, Alberta. The Dixonville property is a horizontal well waterflood producing from the Montney "C" oil pool and is operated by the other working interest owner. The pool is characterized by low declines, a stable production base and low ongoing capital requirements. In 2014, the field experienced two line leaks and the operator shut-in the field for a period of time. As a result, capital was directed towards a pipeline remediation program which included liner installation in the emulsion gathering system. The majority of the capital required for the remediation program was incurred prior to the January 1, 2015 effective date of the acquisition. The remaining capital is forecast to occur in the first quarter of 2015, with Eagle's share included as part of the $1.4 million capital forecast in the 2015 budget.

Year-end reserves information

Eagle targets low risk, producing properties with development potential, and maintains or grows production by converting the non-producing portion of those assets into producing assets, thereby sustaining cash flow and distributions. When the Trust makes an acquisition, it expects to record 100% of the acquired proved plus probable reserves and then develop those reserves over time, ultimately moving reserves from the probable to the proved category.

The Dixonville asset is a fully developed, long-life waterflood property. Only maintenance capital is planned for 2015 and no significant new drilling or production increases are anticipated. However, as the Dixonville asset has a very low recovery factor compared to its total booked reserves, Eagle anticipates that future capital opportunities will arise which will serve to enhance the recovery factor of the field.

An independent evaluation of the Trust's U.S. reserves was conducted by Netherland, Sewell & Associates, Inc. and of the Trust's Canadian reserves by McDaniel and Associates Consultants Ltd. These reserves evaluation reports are effective December 31, 2014 and were prepared in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

2014 year-end reserves report - highlights

- Increased proved developed producing volumes by 88% and the value (PV10) by 29%.
- 98% of the proved developed producing reserves are light oil, 0.5% are natural gas liquids and 1.5% are natural gas.
- Closed two acquisitions, adding approximately 10.5 million boe of proved plus probable reserves and 1,300 boe/d of production at an acquisition cost, including future development costs, of approximately $14.50/boe.
- Achieved a 12% year over year increase in total proved plus probable reserves to approximately 16 million boe (71% proved, 61% proved producing).
- Improved Eagle's proved plus probable reserve life index to 14 years.

The following tables summarize the independent reserves estimates and values of Eagle's reserves as at December 31, 2014:

Summary of reserves

	Company Gross[(1)(2)]				
Reserves category	Crude Oil	Natural Gas Liquids	Natural Gas	**Total Oil Equivalent 2014**	Total Oil Equivalent 2013
	(Mbbls)	(Mbbls)	(MMcf)	**(Mboe)**	(Mboe)
Proved					
Developed producing	9,590	37	871	9,773	5,189
Developed non-producing	363	13	122	397	1,350
Undeveloped	1,211	0	7	1,212	4,383
Total proved	11,164	51	1,000	**11,381**	10,922
Total probable	4,591	2	193	**4,624**	3,407
Total proved plus probable	15,755	52	1,194	**16,006**	14,329

Notes:

(1) Company gross reserves are Eagle's total working interest share before the deduction of any royalties and without including any of Eagle's royalty interests.

(2) Totals may not add due to rounding.

Summary of net present value of future net revenue of reserves

Reserves category	Net Present Value of Future Net Revenue(1) Before Income Taxes Discounted at (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)
Proved					
Developed producing	389,604	246,797	180,405	143,665	120,612
Developed non-producing	18,744	13,807	10,657	8,517	6,987
Undeveloped	40,094	30,507	24,261	19,716	16,224
Total proved	448,442	291,111	215,323	171,897	143,823
Total probable	217,201	98,507	62,406	46,153	36,602
Total proved plus probable	665,643	389,619	277,729	218,051	180,425

Notes:

(1) It should not be assumed that the present values of estimated future net revenue shown above are representative of the fair market value of the reserves. There is no assurance that such price and costs assumptions will be attained and variances could be material. The recovery and estimates of reserves provided in this MD&A 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.

At a 10% discount factor, proved developed producing reserves comprise 65% (2013 – 49%) of the total proved plus probable value. Total proved reserves account for 78% (2013 – 74%) of the total proved plus probable value.

Future development cost

Total future development costs are estimated at $26.2 million for total proved reserves and $43.0 million for total proved plus probable reserves. When compared to 2015 funds flows guidance of $29.5 million (based on $US 60 WTI oil price and a $1.25 FX rate), future development costs represent a conservative 0.9 years and 1.5 years of funds flow.

(This space left blank intentionally)

Reserves performance ratios

During 2014, Eagle's capital expenditures, including acquisition capital, resulted in capital efficiency statistics as shown in the following table. Statistics which cannot be meaningfully calculated are shown as a dashed line.

	2014		2013	
	Proved	**Proved plus Probable**	Proved	Proved plus Probable
Reserves (Mboe)	11,381	16,006	10,922	14,329
Capital Expenditures ($M)				
Exploration and Development (E&D)(1)	13,037	13,037	30,226	30,226
Acquisition(2)	106,319	106,319	35,855	35,855
Disposition(2)	(150,141)	(150,141)	-	-
Disposition (related E&D)	11,286	11,286	-	-
Total Capital Expenditures	(19,465)	(19,465)	66,081	66,081
Field Netbacks ($/boe)(3)				
Current Year	49.75	49.75	52.23	52.23
Three year weighted average	49.76	49.76	-	-
Finding and Development Costs				
Change in future development capital ($M)	7,165	14,495	(18,567)	(17,350)
Reserve additions (Mboes)	892	989	(504)	(2,358)
F&D Costs including changes in FDC ($/boe)(5)	22.65	27.85	-	-
F&D Costs excluding changes in FDC ($/boe)(5)	14.62	13.19	-	-
F&D Recycle Ratio(4)	2.20	1.79	-	-
F&D three year weighted costs ($/boe)	-	4.79	-	-
F&D recycle ratio three year weighted average	-	-	-	-
Finding, Development and Acquisition Expenditures(5)				
Change in future development capital ($M)	11,535	18,865	(17,339)	(16,042)
Reserve additions (Mboes)	8,529	11,517	1,409	(207)
FD&A Costs including changes in FDC ($/boe)(5)	15.35	12.00	34.59	-
FD&A Costs excluding changes in FDC ($/boe)(5)	13.99	10.36	46.90	-
FD&A Recycle Ratio(4)	3.24	4.15	1.51	-
FD&A three year weighted costs ($/boe)	26.69	-	-	-
FD&A recycle ratio three year weighted average	2.11	1.94	-	-
Reserves replacement(6)	145%	265%	128%	-
Reserves life index (yrs)(7)	10.2	14.4	8.9	11.7

Notes:

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

(2) Acquisition relates to the December 2014 asset acquisition in Dixonville. Disposition relates to the August 2014 divestiture of the Permian properties.

(3) Field netbacks are calculated by subtracting royalties and operating costs from revenues.

(4) The recycle ratio is calculated using Eagle's 2014 field netback of $49.75 per boe (2013 - $52.23 per boe) (see the Field Netback section of this MD&A) and dividing that number by the FD&A costs per boe.

(5) Eagle calculates finding and development ("F&D") and finding, development and acquisition ("FD&A") costs, incorporating both the costs and associated reserve additions related to development capital and acquisitions during the year. Both the F&D and the FD&A calculations shown exclude the Permian disposition and Permian development capital spent during 2014. As the Permian property was sold mid-year, no independent reserve assessment was prepared to provide the reserve additions related to the capital that was spent on the Permian property in 2014, therefore the F&D calculation cannot be accurately calculated. In addition, as the proceeds of the Permian disposition exceeded the acquisition costs, including the disposition in the FD&A would have resulted in a negative number. Since acquisitions have a significant impact on Eagle's annual reserve replacement costs, Eagle believes that the FD&A costs shown, excluding the Permian disposition, provide a more meaningful portrayal of Eagle's cost structure.

(6) The reserves replacement ratios are calculated by dividing total reserve additions by total working interest production for the year.

(7) The 2014 reserve life index calculation is based on the mid-point of Eagle's 2015 average working interest production guidance of 3,050 boe/d and the 2013 reserve life index calculation was based on 3,350 boe/d.

Selected annual information

The following table shows selected information for the Trust's fiscal year ended December 31, 2014, December 31, 2013 and December 31, 2012.

Year ended December 31	**2014**	2013	2012
($000's except per unit amounts and production)			
Sales volumes – boe/d	2,782	3,004	2,596
Revenue, net of royalties	67,175	69,210	56,997
Field netback	50,522	57,260	44,962
Funds flow from operations	33,958	44,271	35,298
per unit – basic	1.01	1.44	1.43
per unit - diluted	1.00	1.44	1.33
Earnings (loss)	(48,028)	4,914	6,117
per unit – basic	(1.43)	0.16	0.25
per unit - diluted	(1.55)	0.16	0.24
Current assets	33,245	9,889	14,464
Current liabilities	10,720	30,461	17,512
Total assets	257,172	335,679	284,802
Total non-current liabilities	57,547	70,521	42,111
Unitholders' equity	188,905	234,697	225,179
Distributions declared	33,524	32,434	26,816
per issued unit	0.99	1.05	1.05
Units outstanding for accounting purposes	35,017	32,149	29,269[1]
Units issued	35,017	32,149	29,374

Notes:

(1) Units outstanding for accounting purposes exclude 105,417 units issued due to the performance conditions that had to be met to enable such units to be released from escrow.

Results of operations

Production

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	%	**Year Ended December 31, 2014**	Year Ended December 31, 2013	%
Oil (bbl/d)	1,815	2,452	(26)	2,357	2,484	(5)
Natural gas (Mcf/d)	296	1,413	(79)	1,226	1,360	(10)
Natural gas liquids (bbl/d)	65	307	(79)	221	293	(25)
Oil equivalent sales volumes (boe/d @ 6:1)	**1,929**	2,994	(36)	**2,782**	3,004	(7)

Working interest sales volumes for the year ended December 31, 2014 averaged 2,782 boe/d (85% oil, 8% natural gas liquids, 7% natural gas), 7% below December 31, 2013 average sales volumes. Total 2014 sales volumes decreased year over year due to the disposition of the Permian assets on August 29, 2014. The Trust's average working interest sales volume following the disposition date was approximately 1,900 boe/d.

Revenue

($000's)	**Three Months Ended December 31, 2014**	Three Months Ended December 31, 2013	**%**	**Year Ended December 31, 2014**	**Year Ended December 31, 2013**	%
Oil	$ 13,778	$ 22,395	(38)	$ 86,867	$ 91,183	(5)
Natural gas	90	459	(80)	1,978	1,784	11
Natural gas liquids	76	1,029	(93)	2,999	3,793	(21)
Other	128	-	100	569	-	100
Sales before royalties	**$ 14,072**	$ 23,882	(41)	**$ 92,413**	$ 96,760	(4)

Realized prices						
Oil ($/bbl)	$ 82.51	$ 99.30	(17)	$ 100.99	$ 100.71	-
Natural gas ($/Mcf)	3.32	3.53	(6)	4.42	3.60	22
Natural gas liquids ($/bbl)	12.70	36.36	(65)	37.16	35.44	6
Other ($/bbl)	0.72	-	100	0.56	-	100
Sales before royalties ($/boe)	79.28	86.70	(9)	91.01	88.25	3
Royalties ($/boe)	(21.61)	(24.55)	(12)	(24.86)	(25.13)	(2)
Revenue ($/boe)	**$ 57.67**	$ 62.15	(7)	**$ 66.15**	$ 65.27	1

Benchmark prices						
Oil – WTI ($US/bbl)	**$ 73.15**	$ 97.46	(25)	**$ 93.00**	$ 97.98	(5)
Natural gas – Henry HUB ($US/Mcf)	**$ 3.85**	$ 3.86	-	**$ 4.28**	$ 3.68	16

For the three months ended December 31, 2014, sales revenue decreased by 41% when compared to the prior year's comparative period and by 33% when compared to the third quarter of 2014. The decrease is attributable to lower sales volumes following the sale of the Permian properties on August 29, 2014, and lower realized oil prices resulting from the 25% decline in the WTI benchmark price compared to the fourth quarter of 2013. For the year ended December 31, 2014, sales revenues decreased by 4% year over year as production volumes declined by 7%, while realized prices were commensurate with the prior year.

There is a quality differential between the benchmark WTI price and the $US price realized by the Trust. Eagle enters into field marketing contracts to obtain the most favourable pricing. Management monitors pricing regularly and endeavours to maximize realized sales prices while minimizing counterparty risk.

For the Salt Flat properties, the field marketing contracts use Louisiana Light Sweet ("LLS") as a benchmark reference price instead of WTI. From May through to November, Eagle's marketing contract held all other field pricing adjustments fixed but let the LLS-WTI differential float. From December 1, 2014 to May 31, 2015, Eagle's marketing contract holds all other field pricing adjustments fixed and allows the LLS-WTI differential and the Argus P+ differential to float.

For the Hardeman properties, the field marketing contracts from May 2014 through May 31, 2015 use WTI as a reference price. These contracts hold all other field pricing adjustments fixed.

The above prices do not include realized gains or losses from financial commodity contracts, which amounted to a realized gain of $3.2 million ($17.76/boe) for the three months ended December 31, 2014 and a realized gain of $0.1 million ($0.15/boe) for the year ended December 31, 2014. See *Realized and unrealized risk management gain/loss.*

Realized prices are subject to fluctuations in foreign exchange rates as the Trust's revenue is converted to Canadian dollars, the presentation currency of the Trust. For the quarter ended December 2014, the benchmark WTI ($US/bbl) decreased by 25% from the prior year's comparative quarter. This is comparable to the decrease in the realized oil price, as the increase in the differential between the Trust's realized oil price and the WTI benchmark was offset by a much weaker Canadian dollar. For the year ended December 31, 2014 and 2013, the benchmark WTI ($US/bbl) decreased by 5%, yet the realized oil price held steady due to the weaker Canadian dollar.

For the three months and year ended December 31, 2014, revenue was reduced due to reclassification of oil transportation expenses by $2.05 per boe and $1.75 per boe, respectively. For the three months and year ended December 31, 2013, this reclassification resulted in a revenue reduction of $2.22 per boe and $1.83 per boe, respectively. Refer to "Oil transportation expenses", below.

The overall royalty rate of approximately 27% was consistent with prior periods for the year ended December 31, 2014.

Operating costs

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	%	**Year Ended December 31, 2014**	Year Ended December 31, 2013	%
	$/boe	$/boe		**$/boe**	$/boe	
Marketing expenses	0.23	0.12	87	0.58	0.49	19
Operating costs	18.91	14.45	31	15.82	10.41	52
	19.13	14.45	31	**16.40**	10.90	50

The 31% and 50% increase in per boe operating costs for the three months and year ended December 31, 2014 was primarily due to reduced production volumes following the disposition of the Permian properties on August 29, 2014 and additional salt water disposal costs on the Hardeman properties. Eagle continues to implement initiatives to reduce operating costs at its Salt Flat and Hardeman properties. Refer to the "Operations update" section of this MD&A.

Oil transportation expenses

Historically, the Trust has included oil transportation charges as a component of transportation and marketing expenses. Following a review of the Trust's crude oil contracts during the previous quarter, it was determined that the criteria for revenue recognition are met at the point of sale before the crude oil is transported by its purchasers, and oil transportation changes should be treated as a reduction of the Trust's revenue rather than as a transportation and marketing expense. Consequently, the Trust has stated its revenue and transportation and marketing expense for the three months and year ended December 31, 2014, and restated its revenue and transportation and marketing expense retroactively for the 2013 comparative periods, to reflect this reclassification. There is no net impact on funds flow from operations.

For the three months and year ended December 31, 2014, transportation and marketing expenses were reduced for the reclassification of oil transportation expenses by $2.05 per boe and $1.75 per boe, respectively. For the three months and year ended December 31, 2013, this reclassification resulted in an operating cost reduction of $2.22 per boe and $1.83 per boe, respectively.

Depreciation, depletion, amortization and impairment

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	%	**Year Ended December 31, 2014**	Year Ended December 31, 2013	%
	$/boe	$/boe		**$/boe**	$/boe	
Depreciation, depletion and amortization	**40.54**	31.75	11	**35.12**	28.29	24
Impairment	**278.57**	-	100	**68.47**	-	100
Total depreciation, depletion, amortization and Impairment	**319.11**	31.75	-	**103.59**	28.29	266

The depletion, depreciation, and amortization rate per boe for the three months and year ended December 31, 2014 has increased over the prior year due to the reduction in production volumes following the disposition of the Permian properties on August 29, 2014. On a year over year basis, the depletable base of the remaining assets has grown by more than the relative increase to proved plus probable reserves.

The depletion, depreciation and amortization provision was based on proved plus probable reserves, including the future development costs associated with those reserves, as outlined in the year end 2014 reserves evaluation reports prepared by the Trust's independent reserves evaluators.

For the year ended December 31, 2014, the Trust recognized a $69.5 million (year ended December 31, 2013 - $nil) impairment on its oil and gas properties in relation to the Salt Flat and Permian cash-generating units (each a "**CGU**"). For the three months ended December 31, 2014, the Trust recognized a $49.2 million (three months ended December 31, 2013 - $nil) impairment on its oil and gas properties in the Salt Flat CGU. The impairment was primarily a result of: (i) the decrease in forecast benchmark commodity prices at December 31, 2014 compared to December 31, 2013, (ii) a higher risk adjusted discount rate of 10% used at December 31, 2014 compared to a discount rate of 8% used at December 31, 2013, and (iii) minor technical revisions that resulted in a year over year reduction of the producing component of the probable reserves in Salt Flat. The risk adjusted rate of 10% used to determine the fair value at the measurement date was based on Level 3 value inputs. To calculate the impairment, the fair value less costs to dispose of the assets for each CGU was estimated and then compared to the net book value for each CGU. The Salt Flat CGU was written down to its recoverable amount of $68.1 million based on the fair value less costs to dispose. The fair value was calculated by taking the net present value of the after tax cash flows from its oil and gas proved plus probable reserves as estimated by the third party reserve evaluators, discounted at a rate of 10% (compared to a discount rate of 8% in the prior year). An improvement in reserve estimates or commodity pricing could reverse any impairment charges recorded (after accounting for depletion and depreciation charges otherwise applicable). The remaining impairment charge of $20.3 million related to the sale of the Permian property assets on August 29, 2014 as the disposition proceeds were less than the book value of the Permian CGU.

At December 31, 2013 no impairment was recognized on the Trust's oil and gas properties.

Field netback

	Three Months Ended December 31, 2014		Three Months Ended December 31, 2013		**Year Ended December 31, 2014**		Year Ended December 31, 2013	
($000's)	**$**	**$/boe**	$	$/boe	**$**	**$/boe**	$	$/boe
Sales before royalties	14,072	79.28	23,882	86.69	92,413	91.01	96,760	88.25
Royalties	(3,835)	(21.61)	(6,762)	(24.55)	(25,238)	(24.86)	(27,550)	(25.13)
Operating expenses	(3,357)	(18.91)	(3,368)	(12.22)	(16,062)	(15.82)	(9,405)	(8.57)
Marketing expenses	(39)	(0.23)	(646)	(2.34)	(592)	(0.58)	(2,545)	(2.32)
Field netback	**$ 6,841**	**38.53**	$ 13,106	$ 47.58	**$ 50,521**	**49.75**	$ 57,260	$ 52.23
Sales volumes (boe/d)		**1,929**		2,994		**2,782**		3,004

During the quarter, benchmark WTI averaged $US 73.15 per barrel and the Trust realized a field netback of $38.53 per barrel. For the year ended December 31, 2014, benchmark WTI averaged $US 93.00 per barrel and the Trust realized a field net back of $49.75 per barrel. When compared to the prior year comparative periods, the decrease in field netbacks is due to the reduction in sales volumes as a result of the Permian property disposition on August 29, 2014 and increased operating expenses in the Hardeman properties, which were not operated by Eagle until January 2014. Eagle continues to implement initiatives to reduce operating costs. Refer to the "Operations update" section of this MD&A.

Field netback is a non-IFRS financial measure. See "Non-IFRS financial measures".

Realized and unrealized risk management gain/loss

As part of the Trust's ongoing strategy to mitigate the effects of fluctuating prices on a portion of its production, the following contracts have been put in place:

Commodity:

Oil Fixed Price	**Volume**	**Contract Term**	**Price $US**
NYMEX (1)	190 bbls/d	Jan 2015 to Dec 2015	$85.40
NYMEX (2)	1,000 bbls/d	Jan 2015 to Jun 2015	$90.10 - $92.00
NYMEX (1)	400 bbls/d	Jul 2015 to Dec 2015	$87.90
NYMEX (2)	400 bbls/d	Jan 2015 to Jun 2015	$90.50 - $94.35

(1) Represents a fixed price financial swap transaction with a set forward sale price (WTI reference prices).
(2) Represents costless collar transactions created by buying puts and selling calls (WTI reference prices).

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	%	**Year Ended December 31, 2014**	**Year Ended December 31, 2013**	%
Realized gain (loss)	**$** 3,264	$ 183	-	**$** 302	$ (528)	157
Unrealized gain (loss)	13,109	97	-	15,718	(3,675)	-
Net gain (loss) - Commodity	16,373	280	-	16,020	(4,203)	-
Realized gain (loss)	(111)	-	(100)	(153)	-	(100)
Unrealized gain (loss)	81	-	100	-	-	-
Net gain (loss) - Foreign exchange	(30)	-	(100)	(153)	-	(100)
Total net gain (loss)	**$** 16,343	$ 280	-	**$** 15,867	$ (4,203)	-

On a year over year basis, the net value of the commodity price contracts has increased. The net value of the contracts is dependent upon current and forward commodity pricing and, in the case of realized gains and losses, the price of the contract relative to the benchmark oil price at time of settlement. Although the Trust currently has no intention of unwinding contracts, it is required to calculate and record, using a mark-to-market valuation, the fair value of the remaining term of the contracts at the end of each reporting period, thus changing the value of the unrealized portion of the commodity contracts at each balance sheet date. Continued weakness in the forward commodity pricing environment since the previous quarter of 2014 has strengthened the future value of these contracts on the balance sheet at December 31, 2014.

Based on current estimated working interest production, Eagle was hedged at approximately 86% for the fourth quarter of 2014 at a weighted average price of $US 92.75 per barrel WTI. The Trust is also hedged at approximately 52% for the first half of 2015 at a weighted average price of $US 90.72 per barrel WTI, and at approximately 19% for the second half of 2015 at a weighted average price of $US 87.09 per barrel WTI.

On January 7, 2014, the Trust entered into a foreign exchange contract to mitigate the effects of foreign exchange rate ($CA/$US) fluctuations on monthly distribution payments. The foreign exchange contract had no significant impact on the cost of the Trust's monthly distributions as the Canadian dollar weakened throughout the fourth quarter. As a result, the asset position on the balance sheet at December 31, 2014 was reduced.

Finance expense

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	%	**Year Ended December 31, 2014**	Year Ended December 31, 2013	%
Finance expense	**$** 279	$ 861	(68)	**$** 2,655	$ 2,467	8
Per boe	**1.57**	3.13	(50)	**2.61**	2.25	16

Total finance expense for the three months ended December 31, 2014 decreased over the prior year's comparative quarter due to the full retirement of the Trust's outstanding advances on its credit facility from the disposition date of the Permian assets on August 29, 2014 to the acquisition of the Dixonville assets on December 18, 2014.

For the year ended December 31, 2014, total finance expense increased over the prior year's comparative period due to additional borrowing to fund the Hardeman and Dixonville property acquisitions.

As of December 31, 2014, the effective interest rate on bank debt for the period was 3.2%, which was less than the 3.5% incurred for the comparable period in 2013. During 2014, the Trust utilized advances using the LIBOR rate option which was lower than the base rate option on its borrowings.

Administrative expenses

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	%	**Year Ended December 31, 2014**	Year Ended December 31, 2013	%
Administrative expenses	**$** 3,778	$ 3,525	7	**$** 13,564	$ 8,998	51
Per boe	**21.34**	12.80	67	**13.36**	8.21	63

Administrative expenses for the fourth quarter of 2014 included $0.9 million ($5.11/boe) of one-time transaction costs relating to the acquisition of the Dixonville property including the special unitholders' meeting necessary to approve the amendment to the investment restrictions in Eagle's Trust Indenture to enable the Trust to invest in energy assets in Canada. Also, included in the fourth quarter administrative expenses are other typical fourth quarter charges, including audit and engineering costs.

For the year ended December 31, 2014, administrative expenses were $13.6 million, 51% above the year ended December 31, 2013. This increase was due to one-time costs associated with the disposition of the Permian properties, the acquisition of the Dixonville properties including the costs associated with the special unitholders' meeting, and the internal corporate reorganization. Further, over the past year, engineering, geological, and business development staff were added to assist with full cycle property development, acceleration of the strategic focus on potential acquisitions and management of planned activities. Staff and related employment costs account for 52% of administrative expenses and professional service costs, audit, legal, engineering and tax fees account for 18%.

Unit-based compensation

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	%	**Year Ended December 31, 2014**	Year Ended December 31, 2013	%
Unit-based compensation expense (recovery)	**$ (2,714)**	$ (287)	-	**$ (7,600)**	$ 5,049	-

The recovery of non-cash unit based compensation expense for the three months and year ended December 31, 2014 was due to: (i) a lower unit price at December 31, 2014 when compared to the unit price of prior periods, and (ii) a reduction in the expected unit price volatility since the 2014 calculation incorporates the trading history of the Trust's units rather than incorporating the trading history of a representative sample of peer group entities as was done last year.

The dollar amount of unit based compensation recovery or expense does not represent cash paid (or received) by the Trust.

The actual total value received by holders of the awards will depend on the accumulated distributions actually paid by the Trust combined with (i) the actual year over year price appreciation of the trust units (for holders of the restricted unit rights and unit rights); or (ii) the actual price of the units relative to the exercise price of the options at the time the options are exercised (for holders of options) and which would not result in a cash outlay for the Trust.

The Trust is, however, required to re-determine the fair value of the liability each quarter relating to: (i) the restricted unit rights; (ii) the options; and (iii) the unit rights. Any changes in fair value are recorded as an expense.

From one reporting period to the next, changes in the closing price of the units, accumulated distributions and expected future unit price volatility will increase or decrease the fair values of the unit based awards as calculated under the Black-Scholes valuation model. These fair value changes cause corresponding swings in the amount recorded in the income statement. For the three months and year ended December 31, 2014, the recovery was primarily due to the lower year to date price of the Trust's units.

During the fourth quarter, $0.2 million (three months ended December 31, 2013 - $0.2 million) was paid out in cash for amounts related to restricted unit rights and unit rights, and $0.7 million was paid for the year ended December 31, 2014 (year ended December 31, 2013 - $1.2 million). The liability that was, and continues to be, accrued from inception for these cash settled awards was reduced by such cash payments.

Tax horizon

The tax horizon, as determined from a full cycle corporate model incorporating cash flows from the year end reserves evaluation report plus all applicable Canadian and U.S. deductions, indicates that no material corporate Canadian or U.S. taxes are expected to be payable in respect of income attributable to Eagle's properties for several years. The Trust may be subject to state taxes (Texas) or an alternative minimum tax depending on the deductibility of certain capital expenditures. The Texas state tax and alternative minimum tax rates are at 1% and 20%, respectively. In the case of alternative minimum tax any amount paid can offset any future corporate tax payable. These taxes are not expected to be material.

The Trust is a "mutual fund trust" within the meaning of the Income Tax Act (Canada) (the "Tax Act"). On December 15, 2014, the holders of the Trust units (the "Unitholders") approved a special resolution to amend the investment restrictions contained in the trust indenture governing the Trust. The amendment broadens the investment powers of the Trust, including permitting the Trust, through its subsidiaries, to invest in Canadian energy assets. As a consequence of the investment by one of the Trust's Canadian subsidiaries (Eagle Energy Canada Inc.) in Canadian oil and gas assets on December 18, 2014, the Trust became a "SIFT trust" within the meaning of the Tax Act.

As a SIFT trust, the Trust is taxable only on income that: (i) constitutes "non-portfolio earnings" (within the meaning of the Tax Act); or (ii) is not distributed or distributable to the Unitholders. The Trust's indirect Canadian investment on December 18, 2014 is not anticipated to give rise to any "non-portfolio earnings" since the only income the Trust is expected to receive from the Canadian operations will be in the form of returns of capital or taxable dividends from its Canadian subsidiary. As taxable dividends are paid out of the subsidiary's after-tax corporate income, SIFT tax is not anticipated to apply to the Trust or its affiliates (consistent with the policy behind the SIFT tax regime). The Trust has distributed and will continue to distribute all of its taxable income to the Unitholders. As a consequence, it is not anticipated that the Trust will be subject to any Canadian federal income tax.

As the Trust now holds “taxable Canadian property” (as defined in the Tax Act) it is subject to certain limits on non-resident ownership, and the trust indenture provides certain powers to the trustee in relation thereto.

Summary of quarterly results

($000’s except for boe/d and per unit amounts)	Q4/2014	Q3/2014	Q2/2014	Q1/2014	Q4/2013	Q3/2013	Q2/2013	Q1/2013
Sales volumes – boe/d	1,929	2,859	3,341	3,010	2,994	3,052	3,022	2,928
Revenue, net of royalties	10,238	17,143	20,821	18,973	17,119	19,046	16,698	16,346
per boe	57.67	65.19	68.48	70.04	62.15	67.84	60.73	62.03
Field netback	6,841	12,832	16,144	14,705	13,106	15,945	14,352	13,857
per boe	38.54	48.80	53.10	54.29	47.58	56.79	52.20	52.59
Funds flow from operations	5,670	7,476	10,471	10,341	8,794	11,615	11,977	11,884
per boe	31.94	28.43	34.44	38.18	31.93	41.37	43.56	45.10
per unit – basic	0.16	0.22	0.32	0.32	0.28	0.37	0.39	0.40
per unit – diluted	0.15	0.16	0.28	0.25	0.28	0.37	0.39	0.40
Earnings (loss)	(35,192)	8,104	(23,158)	2,218	156	(3,241)	3,919	4,080
per unit – basic	(1.01)	0.24	(0.70)	0.07	0.00	(0.10)	0.13	0.14
per unit - diluted	(1.13)	0.18	(0.70)	0.02	0.00	(0.10)	0.13	0.14
Cash distributions declared	7,159	9,036	8,775	8,555	8,376	8,204	8,026	7,828
per issued unit	0.2050	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625
Current assets	33,245	76,566	8,802	9,116	9,889	9,950	11,443	9,913
Current Liabilities	10,720	13,587	32,878	33,348	30,461	20,942	19,874	11,982
Total assets	257,172	240,458	320,182	356,332	335,679	306,021	311,271	283,112
Total non-current liabilities	57,547	2,565	80,126	79,684	70,521	55,069	50,654	39,873
Unitholders’ equity	188,905	224,306	207,178	243,300	234,697	230,010	240,743	231,257
Units outstanding for accounting purposes	35,017	34,821	33,739	32,836	32,149	31,469	30,707(1)	29,260(1)
Units issued	35,017	34,821	33,739	32,836	32,149	31,469	30,813	30,066

Note:

(1) Units outstanding for accounting purposes exclude those units issued due to the performance conditions that had to be met to enable such units to be released from escrow.

Funds flow from operations is a non-IFRS financial measure. See “Non-IFRS financial measures”.

For the three months ended December 31, 2014, sales volumes decreased 33% compared to the previous quarter because fourth quarter sales volumes reflect the full quarter impact of the Permian property disposition on August 29, 2014. Prior to the third quarter 2014, with the exception of the fourth quarter 2013, which encountered non-recurring weather related delays and non-owned infrastructure problems, production has generally increased commensurate with well tie-ins and acquisitions. Refer to the sections of this MD&A titled “Liquidity and capital resources - Capital Expenditures, Acquisitions and Activity Summary” for additional information.

Funds flow from operations decreased in the fourth quarter of 2014 when compared to the prior quarter due to weaker commodity prices, the disposition of the Permian property, and additional administrative expenses typical for the fourth quarter. Fourth quarter 2014 funds flow from operations was further tempered by one-time transaction costs associated with the acquisition of the Dixonville property including the special meeting of the unitholders. Generally, in times of steady or increasing prices, funds flow from operations per boe increases when sales volumes increase and decreases when sales volumes decrease. This is because certain expenses tend to be more fixed in nature (such as operating costs, and general and administrative expenses) and do not decrease as sales volumes decrease.

Income (loss) on a quarterly basis often does not move directionally or by the same amount as movements in funds flow from operations. This is primarily due to non-cash items that factor into the calculation of income (loss), and other items which are required to be fair valued at each quarter end. By way of example, fourth quarter 2014 funds flow from operations decreased 24% from the third quarter while the absolute swing from third quarter income to a fourth quarter loss was by a much larger percentage. This occurred because an impairment charge was recognized on Eagle's oil and gas assets in relation to its Salt Flat properties. The effect of the impairment charge was slightly offset by a weaker forward commodity price environment that increased the fourth quarter fair market valuation of Eagle's forward commodity contracts, and the lower unit price at the end of the fourth quarter of 2014 that caused a higher unit-based compensation recovery to be recorded upon performing a fair market valuation of future unit-based payments.

Liquidity and capital resources

Generally, three sources of funding are available to the Trust: (i) internally generated funds flow from operations; (ii) debt financing, when appropriate; and (iii) the issuance of additional units, if available on favourable terms, including proceeds obtained from the Trust's distribution reinvestment program.

Management's objective is to target an external debt to cash flow ratio below 2.0 times. At December 31, 2014, the Trust's ratio of debt to trailing cash flow was approximately 1.1 to 1.0 and includes the December 2014 Dixonville acquisition for $100.9 million.

The Trust believes that its expected funds flow from operations and undrawn credit facility will be sufficient to fund its current and expected financial obligations. Refer to the "Outlook" section for a discussion of the Trust's future plans. Other than the items noted in the "Commitments" section of this MD&A, capital spending and distributions are discretionary.

Funds flow from operations

The following table summarizes funds flow from operations on an absolute and on a per boe basis:

	Three Months Ended December 31, 2014		Three Months Ended December 31, 2013		**Year Ended December 31, 2014**		Year Ended December 31, 2013	
($000's)	**$**	**$ $/boe**	$	$ $/boe	**$**	**$ $/boe**	$	$ $/boe
Field netback	6,841	38.53	13,106	47.58	50,521	49.75	57,260	52.23
Cash settled award payments	(166)	(0.93)	(166)	(0.60)	(694)	(0.68)	(1,189)	(1.08)
Administrative expenses	(3,788)	(21.34)	(3,525)	(12.80)	(13,564)	(13.36)	(8,997)	(8.21)
Realized risk management gain (loss)	3,153	17.76	183	0.66	149	0.15	(528)	(0.48)
Finance expense	(186)	(1.04)	(770)	(2.79)	(2,188)	(2.16)	(2,154)	(1.97)
Income taxes	(210)	(1.18)	-	-	(210)	(0.20)	-	-
Realized foreign exchange gain (loss)[1]	26	0.14	(34)	(0.12)	(56)	(0.06)	(121)	(0.11)
Funds flow from operations	**$ 5,670**	**$ 31.94**	$ 8,794	$ 31.93	**$ 33,958**	**$ 33.44**	$ 44,271	$ 40.38

Note:

(1) This represents settled foreign currency transactions related to operating activities.

Funds flow from operations is a non-IFRS financial measure. See "Non-IFRS financial measures".

Credit facility

As of December 31, 2014, the Trust had approximately $34.0 million ($US 29.3 million) of unused credit on its $81.2 million ($US 70 million) revolving credit facility, which is held indirectly through its subsidiaries with a syndicate of Canadian chartered banks.

As a result of the Dixonville acquisition on December 18, 2014, Eagle's credit facility was further expanded to $US 95 million in February 2015. Amounts drawn on the credit facility can be denominated in US or Canadian dollars and be used for activities in either the United States or Canada. Borrowing on the revolving credit facility is by way of LIBOR and base rate loans for amounts drawn in US funds and banker's acceptance and prime rate loans for amounts drawn in Canadian funds and are subject to a pricing grid based upon debt to EBITDAX rates not exceeding 3:1. The credit facility has a maturity date of May 27, 2016 and is subject to semi-annual redetermination by the credit facility no later than May 15 and October 16 of each year. The next redetermination date is April 1, 2015. EBITDAX is a non-IFRS financial measure. See "Non-IFRS financial measures."

Working capital

At December 31, 2014, the Trust had a working capital surplus, excluding non-cash unit-based payments and non-cash risk management asset, of approximately $8.9 million and $47.2 million ($US 40.7 million) drawn on its bank credit facility described above.

Unitholders' equity

All Trust capital issuances for the three months and year ended December 31, 2014 were issued pursuant to the distribution reinvestment plan as detailed below.

As a result of its DRIP, the Trust received proceeds resulting from the issuance of units from treasury to those unitholders who have opted to participate in the DRIP. Commencing with the distribution paid on October 23, 2014, Eagle suspended the Premium Distribution™ component of the DRIP and amended the DRIP to reduce the market discount that units can be acquired for under the regular distribution reinvestment component from 5% to 2%. Additionally, the Trust has suspended the regular distribution reinvestment component of the DRIP commencing with the distribution paid on February 23, 2015.

A summary of the number of units issued, proceeds resulting from the issuance of units and average price per unit resulting from the DRIP during the three months and year ended December 31, 2014 and December 31, 2013 were as follows:

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	%	**Year Ended December 31, 2014**	Year Ended December 31, 2013	%
Number of units issued	196,555	680,036	(71)	2,868,203	2,879,766	-
Fair market value of units issued under the DRIP	(62)	-	(100)	2,319	-	100
Net proceeds from issuance of Trust Capital (000's)	$ 773	$ 5,195	(85)	$ 17,421	$ 20,173	(16)
Average price per unit	$ 3.93	$ 7.64	(57)	$ 6.07	$ 7.30	(17)

Management may also seek to issue additional units in the future to provide sufficient capital to fund growth, including acquisition opportunities.

For the one year period commencing January 21, 2015 and ending January 20, 2016, the Trust initiated an NCIB. Eagle can purchase for cancellation up to 2,852,829 of its units, representing ten percent of its public float at January 16, 2015. Purchases will be made through an automatic unit purchase plan with a broker in order to facilitate the repurchase of the Trust's units under its NCIB. The purchase of units will be at the prevailing market price of the Trust's units at the time of purchase and will be subject to a maximum daily purchase volume of 30,732 units (being 25% of the average daily trading volume of the Trust's units from July 1, 2014 to December 31, 2014 of 122,928 units) except as otherwise permitted under the NCIB rules of the Toronto Stock Exchange.

Distributions and outstanding unit data

The Trust pays monthly distributions to unitholders at the discretion of the Board of Directors. Cash distributions paid in the fourth quarter (for the September, October, and November 2014 record dates) totaled approximately $9.2 million and totaled $35.2 million for the year.

At December 31, 2014, the Trust had issued 35,017,112 units (December 31, 2013 - 32,148,909 units).

As at the date of this MD&A, 35,023,364 units are issued and 3,338,418 options are outstanding. The Trust has purchased for cancellation 30,300 units under its NCIB.

As required by National Policy 41-201, "Income Trusts and Other Indirect Offerings", the following table outlines the differences between net income and cash distributions paid as well as the differences between net cash provided by operating activities and cash distributions paid.

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	**Year Ended December 31, 2014**	Year Ended December 31, 2013
(000's)	**$**	$	**$**	$
Earnings (loss) for the period	(35,192)	156	(48,028)	4,914
Cash distributions paid	(9,155)	(8,133)	(35,287)	(32,191)
Excess (shortfall) of earnings (loss) over cash distributions paid	**(44,347)**	(7,977)	**(83,315)**	(27,277)
Funds flow from operations(1)	5,670	8,794	33,958	44,271
Changes in working capital	870	(1,494)	2,579	(2,579)
Abandonment expenditures	(212)	-	(212)	(9)
Net cash provided by operating activities	6,328	7,300	36,325	41,683
Cash distributions paid	(9,155)	(8,133)	(35,287)	(32,191)
Excess (shortfall) of net cash provided by operating activities over cash distributions paid	**(2,827)**	(833)	**1,038**	9,492

Note:

(1) See "Non-IFRS financial measures".

For the three months and year ended December 31, 2014 and December 31, 2013, cash distributions paid exceeded earnings (loss) for the period due to the non-cash items that are deducted or added in determining earnings for the period. Earnings often does not move directionally or by the same amount as movements in net cash provided by operating activities. This is primarily due to items of a non-cash nature that factor into the calculation of earnings, as well as those that are required to be fair valued at each period end. Examples of non-cash items include depreciation, depletion and amortization, impairment, unit-based compensation and unrealized risk management losses, all of which have no impact on cash available to pay distributions.

For the three months ended December 31, 2014, cash distributions paid exceeded net cash provided by operating activities by approximately $2.8 million (December 31, 2013 – $0.8 million) due to: (i) the decrease in fourth quarter production revenue following the disposition of the Permian properties on August 29, 2014, (ii) increased general and administrative expenses from one-time transaction costs for the acquisition of the Dixonville property and the special unitholders' meeting; and (iii) lower realized commodity prices. Effective with the December 2014 distribution, the Trust took action to protect its balance sheet in light of current and expected commodity prices by lowering its monthly distribution to $0.03 per unit per month from $0.0875 per unit per month.

For the year end December 31, 2014 and December 31, 2013, net cash provided by operating activities were in excess of distributions paid.

Cash distributions paid in the fourth quarter of 2014 were 13% higher than in the fourth quarter of 2013 due to the higher number of outstanding units. Also, as a result of the low trading price of its units, the Trust suspended the Premium Distribution™ component of its DRIP and amended the DRIP to reduce the market discount that the Trust's units can be acquired for under the regular distribution reinvestment component from 5% to 2% in September 2014. Commencing with the distribution paid on February 23, 2015, the Trust suspended the regular distribution reinvestment component of the DRIP and initiated a NCIB which allows for purchase for cancellation of up to 2,852,829 units of the Trust.

Capital expenditures

Capital spending during the quarter and year ended December 31, 2014 and December 31, 2013 was as follows:

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	**Year Ended December 31, 2014**	Year Ended December 31, 2013
(000's)	**$**	$	**$**	$
Exploration and evaluation[1]	(16)	-	-	63
Acquisition – Hardeman-2013	-	27,087	-	27,087
Acquisition – Hardeman-2014	-	-	5,409	-
Acquisition - Permian - 7.5% interest	-	(62)	-	8,768
Disposition – Permian	6	-	(150,141)	-
Acquisition – Dixonville	100,910	-	100,910	-
Intangible drilling and completions	2,892	1,017	18,194	26,198
Seismic	458		3,742	
Well equipment and facilities	859	388	2,360	3,856
Proceeds from disposal of assets	-	(106)	-	(106)
Other	10	18	61	215
	$ 105,119	$ 28,342	**$ (19,465)**	$ 66,081

Note:

(1) Exploration and evaluation expenditures relate to amounts spent on land to which no proven reserves are yet assigned.

During the fourth quarter of 2014, the Trust spent $3.7 million on drilling, completions, tie-ins and recompletions. Of this total, $3.3 million was spent to drill and tie-in two Hardeman wells and $0.4 million to recomplete existing wells in Hardeman and Salt Flat. In addition, $0.5 million was spent for seismic processing in the Hardeman properties. Refer to the "Operations update" section of this MD&A.

Eagle is well positioned for growth with financial flexibility and operational strength. The Trust intends to continue to actively pursue acquisitions in the U.S. and Canada.

Property acquisitions

Dixonville property

On December 18, 2014, the Trust's newly established Canadian operating subsidiary, Eagle Energy Canada Inc., acquired a 50% non-operated working interest in producing properties in the Dixonville Montney "C" oil pool located in north central Alberta for cash consideration of $100.9 million, which includes preliminary closing adjustments of $909,620. The closing adjustments are subject to change. The acquisition established a new strategic Canadian property and diversified the Trust's portfolio of petroleum assets.

Consideration consisted of cash. The acquisition has been accounted for as a business combination with the fair value of the net assets as follows:

Identifiable assets acquired and liabilities assumed ($CA):

Oil and gas properties	$ 101,294
Decommissioning liabilities	(384)
	$ 100,910

Hardeman properties

On February 27, 2014, the Trust's U.S. operating subsidiary acquired undeveloped acreage and an average 66% working interest in producing properties in Hardeman County, Texas and in Greer, Harmon and Jackson counties, Oklahoma for cash consideration of $5.4 million. The acquisition increased Eagle's established position in Hardeman County.

Consideration consisted of cash. The acquisition has been accounted for as a business combination with the fair value of the net assets as follows:

Identifiable assets acquired and liabilities assumed ($CA):

Oil and gas properties	$	5,497
Decommissioning liabilities		(88)
	$	**5,409**

Property disposition

Permian property

On August 29, 2014, the Trust's U.S. operating subsidiary closed the sale of its entire working interest in oil and natural gas properties in the Permian Basin, located near Midland, Texas, for net proceeds of $150.1 million ($US 140 million) after closing adjustments. Prior to its disposition the Trust recognized an impairment charge on the asset, reducing its carrying value to its net realizable value. Accordingly, no gain or loss was recorded on the sale.

Proceeds consisted of cash. The disposition has been accounted for as follows:

Identifiable assets and liabilities disposed of ($CA):

Oil and gas properties	$	151,330
Decommissioning liabilities		(1,189)
	$	**150,141**

Activity summary

Wells drilled (rig-released)	**Three Months Ended December 31, 2014**		Three Months Ended December 31, 2013		**Year Ended December 31, 2014**		Year Ended December 31, 2013	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Salt Flat	-	-	1	1.0	3	2.4	7	6.2
Permian	-	-	-	-	2	2.0	5	5.0
Hardeman	2	2.0	-	-	2	2.0	-	-
Total	**2**	**2.0**	1	1.0	**7**	**6.4**	12	11.2

Wells brought on-stream	**Three Months Ended December 31, 2014**		Three Months Ended December 31, 2013		**Year Ended December 31, 2014**		Year Ended December 31, 2013	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Salt Flat	-	-	-	-	3	2.4	6	5.2
Permian	-	-	-	-	2	2.0	6	6.0
Hardeman	2	2.0	-	-	2	2.0	-	-
Total	**2**	**2.0**	-	-	**7**	**6.4**	12	11.2

Refer to the "Operations update" section at the beginning of this MD&A.

Commitments

The Trust has committed to future payments as follows:

(000's)		**Total**		**Less than 1 year**		**1 – 3 years**		**After 3 years**
Operating leases (1)(2)		2,524		823		1,660		41
Total contractual obligations	**$**	**2,524**	**$**	**823**	**$**	**1,660**	**$**	**41**

Notes:

(1) Calgary, Alberta office lease: On January 1, 2013, the Trust entered into a lease for office space in Calgary which has an approximate 61 month term from January 8, 2013 to February 7, 2018. Future minimum lease payments during the term of the lease approximate

$2.4 million and include an available leasehold improvements allowance up to $0.3 million, with 37 months and approximately $1.5 million remaining at December 31, 2014.

(2) Houston, Texas office lease: the Trust entered into a lease in Houston on April 1, 2011, which had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease was extended for an additional 63 month period from October 1, 2013 to December 31, 2017 and the premise space was expanded to incorporate additional square footage. Future minimum lease payments during the term of the lease include a leasehold improvements allowance of $US 0.1 million and approximate $US 0.9 million with 36 months and approximately $US 0.9 million remaining at December 31, 2014. In $CA the remaining future minimum lease payments approximate $1.0 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.16.

Legal proceedings

The Trust is involved in various litigation and claims in the normal course of the Trust's operations. Although the outcome of these claims cannot be predicted with certainty, the Trust does not expect these matters to have a material adverse effect on Eagle's financial position, cash flows or results of operations. If an unfavorable outcome were to occur, there exists the possibility of a material adverse impact on the Trust's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Trust determines that the loss is probable and the amount can be reasonably estimated. The Trust believes it has made adequate provision for such legal claims.

Transactions with related parties

Key management personnel

Key management personnel includes the Trust's Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, the four Vice-Presidents, General Counsel/Corporate Secretary and the four external Directors.

Intercompany transactions

There are certain intercompany transactions among the subsidiaries comprising the consolidated financial statements of the Trust. These transactions have been eliminated upon consolidation.

Critical accounting estimates and judgments

The Trust makes estimates and judgments concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. Such estimates and judgments are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Estimation of oil and gas reserves

Oil and gas reserves are the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of oil and gas reserves are inherently imprecise, require the application of judgment and are subject to future revision. Accordingly, financial and accounting measures (such as fair value less cost to dispose of property, plant and equipment for the impairment calculation, depletion and decommissioning provisions) that are based on reserves are also subject to change.

Capitalized exploration and evaluation expenditures

In making decisions about whether to continue to capitalize exploration and evaluation expenditures, it is necessary to make judgments about the commercial reserves and the level of activities that constitute on-going evaluation determination. If there is a change in any judgment in a subsequent period, then the related capitalized exploration and evaluation expenditure would be expensed in that period, resulting in a charge to income.

Business combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The consideration transferred in a business combination is measured as the fair value of the assets given, equity instruments issued and liabilities incurred at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the consideration transferred in a business combination over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. Any non-controlling interest or equity interest held which becomes a component of an acquisition is included in the computation of goodwill. If the cost of the acquisition is less than the fair value of the net assets of the subsidiary acquired, the fair value of the net assets is reassessed. Provided the cost remains less than the fair value of the net assets acquired, after reassessment, the difference is recognized in the income statement.

Decommissioning provision

Estimates of the amounts of provision for decommissioning recognized are based on current legal and constructive requirements, technology, and price levels. As actual outflows may be different from estimates due to changes in laws, regulations, technology, prices and conditions, and can take place in the future, the carrying amounts of provisions are regularly reviewed and adjusted to take account of such changes. The Trust has interpreted the accounting standard to use the risk-free discount rate for calculating the present value of the decommissioning obligation.

Impairment of property, plant and equipment

The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to dispose. These calculations require the use of estimates and assumptions. It is reasonably possible that the commodity price assumption may change, which may impact the estimated life of the asset and may require a material adjustment to the carrying value of assets. The Trust monitors recent transaction within the industry, long-term views of commodity prices, externally evaluated reserves volumes and discount rates specific to the CGU.

Income taxes

The Trust recognizes the net future tax benefit related to deferred income tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred income tax assets requires the Trust to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Trust to realize the net deferred tax assets recorded at the balance sheet date could be impacted.

Additionally, future changes in tax laws in the jurisdiction in which the Trust operates could limit the ability of the Trust to obtain tax deductions in future periods.

Derivative financial instruments

As described in the Risk Management section of this MD&A, derivative financial instruments are used by the Trust to manage its exposure to market risks relating to commodity prices. The Trust's policy is not to use derivative financial instruments for speculative purposes. Derivative financial instruments that do not qualify, or are not designated, as hedges for accounting are recorded at fair value. Instruments are recorded in the balance sheet as either an asset or a liability with changes in fair value recognized in the income statement. The estimate of fair value of all derivative instruments is based on quoted market prices, or in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Classification of trust units as equity

Trust units issued by income trusts give the holder the right to put the units back to the issuer in exchange for cash. IAS 32 "Financial Instruments: Presentation" establishes the general principle that an instrument which gives the holder the right to put the instrument back to the issuer for cash should be classified as a financial liability, unless such instrument has all of the features and meets the conditions of the IAS 32 "puttable instrument exemption". If these "puttable instrument exemption" criteria are met, the instrument is classified as equity. The Trust has examined the terms and conditions of its Trust Indenture and classifies its outstanding trust units as equity because the trust units meet the "puttable instrument exemption" criteria as there is no contractual obligation to distribute cash.

Contingencies

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

Unit-based compensation

The amount of compensation expense accrued for compensation arrangements is subject to Management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be. Certain obligations for payments under the compensation plans are measured at fair value and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on several assumptions including risk-free interest rate and the expected volatility of the unit price and therefore is subject to measurement uncertainty.

Accounting standards and interpretations adopted:

The Trust adopted the following new and revised standards, along with any consequential amendments, effective January 1, 2014. These changes were made in accordance with the applicable transitional provisions.

- On January 1, 2014, the Trust adopted International Financial Reporting Interpretations Committee ("IFRIC") Interpretation 21-Levies, which addresses payments to government bodies. There was no material impact to the Trust as a result of adopting the new standard.

- IAS 36 - Impairment of Assets - the IASB issued amendments to IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGU's is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. This amendment is effective for annual periods beginning on or after January 1, 2014.

The Trust will continue to monitor the adoption efforts of industry participants and the efforts of the CICA and industry groups. Additional adjustments to the Trust's accounting policies may be required upon completion of a separate IASB framework for extractive industries.

Accounting standards and interpretations not yet adopted:

- IFRS 9, Financial Instruments, replaces International Accounting Standard 39, Financial Instruments: Recognition and Measurement. IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Trust is currently evaluating the impact of adopting IFRS 9 on the consolidated financial statements.
- IFRS 15, Revenue from contracts with customers, replaces IAS 18 - Revenue and IAS 11 - Construction contracts and provides a new principle based model on revenue recognition to all contracts with customers. Mandatory adoption is effective for periods beginning on or after January 1, 2017. The Trust is currently evaluating the impact of adopting this standard on the consolidated financial statements.

Additional adjustments to the Trust's accounting policies may be required upon completion of a separate IASB framework for extractive industries.

Risk management

For a more detailed description of the risks and uncertainties faced by the Trust, refer to the Trust's Annual Information Form. The Trust's activities expose it to a variety of financial risks that arise as a result of its exploitation, development, production, and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

Credit risk is the risk of financial loss to the Trust if a customer, joint venture partner or counterparty to a financial instrument fails to meet its contractual obligations. It arises principally from the Trust's receivables from its product marketer and joint venture partners. Receivables from the Trust's marketer are normally collected in the month following production. The Trust's policy to mitigate credit risk associated with these balances is to establish marketing relationships with reputable purchasers with good credit and, over time, to spread this risk among as many different marketers as is reasonably feasible. Joint venture receivables are with customers in the oil and gas industry and are subject to normal industry credit risks. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. In certain circumstances, the Trust may request an operating advance or cash call a partner in advance of expenditures being incurred.

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. The approach to managing liquidity is to ensure, as far as possible, that the Trust will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Trust's reputation. At December 31, 2014, the Trust had a working capital surplus, excluding the non-cash current portion of unit based payments and current risk management contracts of approximately $8.9 million, and $ 47.2 million drawn on its $81.2 million ($US 70 million) Canadian dollar equivalent authorized credit facility. To better manage its liquidity risk, the Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil and natural gas revenue each month.

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Trust's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters while optimizing the return.

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar, but also world economic events that dictate the levels of supply and demand. The Trust enters into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. As at the date of this MD&A, the Trust has entered into contracts to mitigate the effect of commodity price fluctuations. Refer to the "Realized and unrealized risk management gain" section of this MD&A.

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. The Trust's operating cash flows are generated in US dollars and distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust's treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil are determined in global markets and denominated in US dollars. Generally, an increase in the value of the $CA as compared to the $US will reduce the prices received by the Trust for its petroleum and natural gas sales, but will also reduce the operating expenses associated with those sales as well as reduce the price paid by the subsidiary of the Trust for future asset acquisitions. During 2014, the Trust entered into foreign exchange contracts to mitigate its foreign exchange exposure on distributions which resulted in a realized net loss of $0.2 million for the year ended December 31, 2014. Refer to the "Realized and unrealized risk management gain" section of this MD&A.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. As at December 31, 2014, $47.2 million had been drawn against the $81.2 million credit facility (December 31, 2013 - $78.1 million drawn against the total credit facility of $95.7 million). The Trust did not hedge against any interest rate exposure.

Non-IFRS financial measures

Statements throughout this MD&A make reference to the terms "field netback", "funds flow from operations", "free cash flow", "basic payout ratio", "corporate payout ratio" and "EBITDAX", which are non-IFRS financial measures that do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that these terms provide useful information to investors and management since such measures reflect the quality of production, the level of profitability, the ability to drive growth through the funding of future capital expenditures and the sustainability of distributions to unitholders.

"**Funds flow from operations**" is calculated before changes in non-cash working capital and abandonment expenditures. Management considers funds flow from operations to be a key measure as it demonstrates Eagle's ability to generate the cash necessary to pay distributions, repay debt, fund decommissioning liabilities and make capital investments. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds flow from operations provides a useful measure of Eagle's ability to generate cash that is not subject to short-term movements in non-cash operating working capital. Refer to the table below for the reconciliation of funds flow from operations to earnings (loss).

"**Field netback**" is calculated by subtracting royalties and operating costs from revenues.

"**Free cash flow**" is calculated by subtracting capital expenditures from field netbacks for the property.

"**Basic payout ratio**" is calculated by dividing unitholder distributions by funds flow from operations.

"**Corporate payout ratio**" is calculated by dividing capital expenditures plus unitholder distributions by funds flow from operations.

"**EBITDAX**" means "earnings before interest, taxes, and depreciation, depletion, amortization and exploration expenses". It is one of the financial measures used in the provisions of the Trust's credit facility for purposes of determining the lending margin ratio and compliance with the borrowing covenants. See the "*Credit facility*" section of this MD&A for a description of the Trust's borrowing covenants.

The following table reconciles the non-IFRS financial measures “funds flow from operations” and “field netback” to “earnings (loss)”, the most directly comparable measure in the Trust’s consolidated financial statements:

(000’s)	**Three Months Ended December 31, 2014**	Three Months Ended December 31, 2013	**Year Ended December 31, 2014**	Year Ended December 31, 2013
Earnings (Loss)	**$ (35,192)**	$ 156	**$ (48,028)**	4,914
Add back (deduct) items not involving cash:				
Unit-based compensation – non-cash portion	(2,880)	(452)	(8,294)	3,859
Unrealized risk management loss (gain)	(13,190)	(97)	(15,718)	3,675
Depreciation, depletion and amortization and impairment	56,840	8,793	105,531	31,206
Loss on disposal of asset	-	303	-	303
Finance expense	92	91	467	314
Funds flow from operations	**$ 5,670**	$ 8,794	**$ 33,958**	44,271
Add back (deduct) items not directly related to field operations:				
Realized foreign exchange loss (gain)	(26)	34	56	121
Finance expense (cash portion)	186	770	2,188	2,154
Risk management (gain) loss-realized	(3,153)	(183)	(149)	528
Administrative expenses	3,788	3,525	13,564	8,997
Income taxes	210		210	
Cash settled award payments	166	166	694	1,189
Field netback	**$ 6,841**	$ 13,106	**$ 50,521**	50,260

Conclusions regarding the design and effectiveness of disclosure controls and procedures

Disclosure controls and procedures are controls and procedures designed to provide reasonable assurance that information required to be disclosed in reports filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis and is accumulated and communicated to the Trust’s management, including the Chief Executive Officer and the Chief Financial Officer as appropriate, to allow timely decisions regarding required disclosure. As at December 31, 2014, the Chief Executive Officer and the Chief Financial Officer evaluated the design and operation of the Trust’s disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the Trust’s disclosure controls and procedures were effective as at December 31, 2014.

Conclusions regarding the design and effectiveness of internal controls over financial reporting

Internal controls are processes designed and implemented by Management to provide reasonable assurance regarding the reliability of the Trust’s financial reporting and the preparation of financial statements and other financial information for external purposes in accordance with IFRS. Based on an evaluation of the Trust’s internal controls over financial reporting as at December 31, 2014, the Chief Executive Officer and the Chief Financial Officer concluded that the Trust’s internal controls over financial reporting were effective.

No change in internal controls over financial reporting during the period October 1, 2014 to December 31, 2014

During the period beginning on October 1, 2014 and ended on December 31, 2014, there was no change in the Trust’s internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust’s internal controls over financial reporting. It should be noted, that the Trust’s control system, no matter how well designed, can provide only reasonable, but not absolute, assurance of detecting, preventing and deterring errors or fraud.

Note about forward-looking statements

Certain of the statements made and information contained in this MD&A are forward-looking statements and forward looking information (collectively referred to as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historic fact are forward-looking statements. The Trust cautions investors that important factors could cause the Trust's actual results to differ materially from those projected, or set out, in any forward-looking statements included in this MD&A. 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 reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

In particular, and without limitation, this MD&A contains forward looking statements pertaining to the following:

- Eagle's 2015 capital and operating budget and specific uses, including Eagle's 2015 drilling plans and potential locations;
- Eagle's expectations regarding its 2015 average working interest production, operating costs, field netbacks, corporate decline rate and funds flow from operations;
- Eagle's expectation that as commodity prices recover, the percentage of free cash flow realized by the Trust will increase;
- Eagle's expectation that it is well positioned to achieve full year 2015 production targets and that its continued focus on operational efficiencies and capital discipline will lead to cost reductions;
- Eagle's expectation that its 2015 budget should be sufficient to sustain production levels and add a designated component of growth focused capital;
- Eagle's expectation that its funds flow from operations and undrawn credit facility will be sufficient to fund its current and expected financial obligations;
- Eagle's projected payout ratios and the sensitivities of funds flow and payout ratios to changes in production rates, exchange rates and commodity prices;
- Management's view in respect of Eagle's financial flexibility, operational strength and sustainability and the Trust's intention to continue to actively pursue acquisitions in the U.S. and Canada;
- projected amount of and sustainability of distributions on the Units;
- projected percentage weighting of oil, gas and NGLs in 2015 production;
- existing credit facilities and the availability of new credit facilities to fund acquisitions;
- the taxability of the Trust and the status of the Trust as a mutual fund trust and a SIFT trust;
- projected debt to cash flow, and management's objective to maintain a debt to cash flow ratio below 2 times;
- estimated reserve life index;
- Eagle's expectation that, on its Dixonville asset, future capital opportunities will arise which will serve to enhance the recovery factor of the field;
- Eagle's business model with respect to acquisitions and reserves booking; and
- estimated volumes and value of Eagle's reserves.

With respect to forward-looking statements contained in this MD&A, assumptions have been made regarding, among other things:

- future oil, natural gas and NGL prices and weighting;
- future currency exchange rates;
- the regulatory framework governing taxes in the US and Canada and the Trust's status as a "mutual fund trust" and a "SIFT trust";
- future production levels;
- future recoverability of reserves;
- future capital expenditures and the ability of the Trust to obtain financing on acceptable terms for its capital projects and future acquisitions;
- future distributions levels;
- the Trust's 2015 capital budget, which is subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions and regulations;
- not including capital required to pursue future acquisitions in the forecasted capital expenditures;
- the ability of the Trust to compete for new acquisitions;
- estimates of anticipated production, which is based on the proposed drilling program with a success rate that, in turn, is based upon historical drilling success and an evaluation of the particular wells to be drilled;
- projected operating costs, which are based on historical information and anticipated increases in the cost of equipment and services; and
- the accuracy of the estimates of Eagle's reserves volumes and values.

The Trust's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included in the Trust's Annual Information Form for the year ended December 31, 2014 ("**AIF**") available on SEDAR at www.sedar.com:

- volatility of oil, natural gas and NGL prices;
- changes in commodity supply and demand;
- fluctuations in currency and interest rates;
- inherent risks and changes in costs associated in the development of petroleum properties;
- ultimate recoverability of reserves;
- timing, results and costs of drilling and production activities;
- availability of financing and capital;
- the regulatory framework governing taxes in the U.S. and Canada and the Trust's status as a "mutual fund trust": and a "SIFT" trust; and
- new regulations and legislation that apply to the Trust and the operations of its subsidiaries.

Additional risks and uncertainties affecting the Trust are contained in the Trust's AIF under the heading "Risk Factors".

As a result of these risks, actual performance and financial results in 2015 may differ materially from any projections of future performance or results expressed or implied by these forward-looking statements. Eagle's production rates, operating costs, 2015 capital budget, funds flow, field netbacks, decline rates, reserves volumes and values, and the Trust's distributions are subject to change in light of ongoing results, prevailing economic circumstances, obtaining regulatory approvals, commodity prices, exchange rates and industry conditions and regulations. New factors emerge from time to time, and it is not possible for management to predict all of these factors or to assess, in advance, the impact of each such factor on the Trust's business, or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statement.

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward looking statements will not occur. Although Management believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date the forward-looking statements were made, there can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Trust and its unitholders. The Trust does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise.

Note regarding barrel of oil equivalency

This MD&A contains disclosure expressed as "boe" or "boe/d". All oil and natural gas equivalency volumes have been derived using the conversion ratio of six thousand cubic feet ("**Mcf**") of natural gas to one barrel ("**bbl**") of oil. Equivalency measures may be misleading, particularly if used in isolation. A 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 well head. In addition, given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of six to one, utilizing a boe conversion ratio of 6 Mcf: 1 bbl would be misleading as an indication of value.

Eagle Energy Trust

Consolidated Financial Statements
(in Canadian dollars)

For the Years Ended December 31, 2014 and December 31, 2013

Management's Report to the Unitholders of Eagle Energy Trust

The accompanying consolidated financial statements of Eagle Energy Trust are the responsibility of the Board of Directors (the "Board").

The consolidated financial statements have been prepared by Management, on behalf of the Board, in accordance with accounting policies disclosed in the notes to the consolidated financial statements. Where necessary, Management has made informed judgments and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of Management, the consolidated financial statements have been prepared within acceptable limits of materiality and are in accordance with International Financial Reporting Standards appropriate in the circumstances.

Management, with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Trust's disclosure controls and procedures and has concluded that such disclosure controls and procedures are effective.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are properly authorized, assets are safeguarded and financial records are properly maintained to provide reliable information for the preparation of financial statements. An independent firm of Chartered Accountants, as appointed by the Board, examines the consolidated financial statements in accordance with International Financial Reporting Standards and provides an independent professional opinion.

The Board carries out its responsibility for the financial reporting and internal controls principally through an Audit Committee. The committee has met with external auditors and Management in order to determine if Management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

(signed) Richard W. Clark
Richard W. Clark
President, Chief Executive Officer
and Director

MARCH 19, 2015

(signed) Kelly A. Tomyn
Kelly A. Tomyn
Chief Financial Officer

MARCH 19, 2015

Independent Auditor's Report to the Unitholders of Eagle Energy Trust

We have audited the accompanying consolidated financial statements of Eagle Energy Trust and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013 and the consolidated statements of earnings and comprehensive income, statements of changes in unitholders' equity and statements of cash flows for the years ended December 31, 2014 and December 31, 2013, and the related notes, which comprise a 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 International Financial Reporting Standards, 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.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit 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 auditor's judgment, including the assessments of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers 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 in our audit 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 financial position of Eagle Energy Trust and its subsidiaries as at December 31, 2014 and December 31, 2013 and its financial performance and its cash flows for the years ended December 31, 2014 and December 31, 2013 in accordance with International Financial Reporting Standards.

(Signed) PricewaterhouseCoopers LLP

Chartered Accountants

March 19, 2015
Calgary, Alberta

Eagle Energy Trust

Consolidated Balance Sheets

(Thousands of Canadian dollars)

	Note		December 31, 2014		December 31, 2013
ASSETS					
Current assets					
Cash		$	11,127	$	1,435
Trade and other receivables			6,669		7,826
Prepaid expenses			530		628
Risk management asset	4		14,919		-
			33,245		**9,889**
Non-current assets					
Exploration and evaluation	15		-		508
Oil and gas properties	16		222,939		324,349
Property, plant and equipment			219		327
Other intangible assets			769		606
			223,927		**325,790**
Total Assets		**$**	**257,172**	**$**	**335,679**
LIABILITIES					
Current liabilities					
Trade and other payables		$	8,316	$	5,929
Distributions payable			1,068		2,813
Unit-based payments	8		1,336		9,630
Risk management liability	4		-		1,453
Current debt			-		10,636
			10,720		**30,461**
Non-current liabilities					
Debt	17		47,200		67,485
Deferred income tax	11		-		-
Decommissioning liability	18		10,347		3,036
			57,547		**70,521**
Total Liabilities		**$**	**68,267**	**$**	**100,982**
UNITHOLDERS' EQUITY					
Trust capital	19	$	317,150		297,447
Currency reserves	9		29,494		11,100
Accumulated earnings			(41,424)		6,604
Accumulated cash distributions	20		(116,315)		(80,454)
Total Unitholders' Equity		**$**	**188,905**	**$**	**234,697**
Total Liabilities and Unitholders' Equity		**$**	**257,172**	**$**	**335,679**

The notes are an integral part of these financial statements.

See Note 22 "Commitments" and Note 23 "Subsequent events".

Eagle Energy Trust

Consolidated Statements of Earnings (Loss) and Comprehensive Income (Loss)

(Thousands of Canadian dollars, except per unit amounts)

	Note	**Year Ended December 31, 2014**	Year Ended December 31, 2013 - Revised[1]
Revenue		$ 92,413	$ 96,760
Royalties		(25,238)	(27,550)
		67,175	**69,210**
Operating expenses		16,062	11,412
Transportation and marketing expenses		592	538
Administrative expenses		13,564	8,998
Impairment	12	69,531	-
Depreciation, depletion and amortization	12	35,846	31,206
Exploration and evaluation	15	154	-
Operating profit (loss)		**(68,574)**	**17,056**
Unit based compensation expense (recovery)	8	(7,600)	5,049
Finance expense	10	2,655	2,467
Loss on disposal of assets		-	303
Risk management loss (gain)	4	(15,867)	4,203
Foreign exchange loss net	9	56	120
Earnings (loss) before taxes		**(47,818)**	**4,914**
Income tax expense	11	210	-
Earnings (loss)		**$ (48,028)**	**$ 4,914**
Other comprehensive income			
Items that may be reclassified subsequently to earnings			
Foreign currency translation gain	9	18,394	16,117
Comprehensive income (loss)		**$ (29,634)**	**$ 21,031**
Earnings (loss) per unit			
Basic	14	**(1.43)**	0.16
Diluted	14	**(1.55)**	0.16

[1] See note 2.2 “Changes in accounting policy and disclosures”.

The notes are an integral part of these financial statements.

Eagle Energy Trust

Consolidated Statement of Changes in Unitholders' Equity

For the years ended December 31, 2014 and December 31, 2013
(Thousands of Canadian dollars)

	Note	Number of Trust Units (000's)	Trust Capital	Currency Reserve	Accumulated Earnings/ Loss	Accumulated Cash Distributions	Deficit	**Total Unitholders' Equity**
Balance at December 31, 2012		**29,269**	**276,526**	**(5,017)**	**1,690**	**(48,020)**	**(46,330)**	**225,179**
Earnings		-	-	-	4,914	-	4,914	4,914
Foreign currency translation gain	9	-	-	16,117	-	-	-	16,117
Total comprehensive income		-	-	16,117	4,914	-	4,914	21,031
Issuance of Trust capital	19	2,880	21,032	-	-	-	-	21,032
Trust unit issuance costs	19	-	(111)	-	-	-	-	(111)
Unitholder distributions	20	-	-	-	-	(32,434)	(32,434)	(32,434)
		2,880	20,921	-	-	(32,434)	(32,434)	(11,513)
Balance at December 31, 2013		**32,149**	**297,447**	**11,100**	**6,604**	**(80,454)**	**(73,850)**	**234,697**
Earnings (loss)		-	-	-	(48,028)	-	(48,028)	(48,028)
Foreign currency translation gain	9	-	-	18,394	-	-	-	18,394
Total comprehensive income (loss)		-	-	18,394	(48,028)	-	(48,028)	(29,634)
Issuance of Trust capital	19	2,868	19,740	-	-	-	-	19,740
Trust unit issuance costs	19	-	(37)	-	-	-	-	(37)
Unitholder distributions	20	-	-	-	-	(35,861)	(35,861)	(35,861)
		2,868	19,703	-	-	(35,861)	(35,861)	(16,158)
Balance at December 31, 2014		**35,017**	**317,150**	**29,494**	**(41,424)**	**(116,315)**	**(157,739)**	**188,905**

The notes are an integral part of these financial statements.

Eagle Energy Trust

Consolidated Cash Flow Statements

For the year ended December 31, 2014 and December 31, 2013
(Thousands of Canadian dollars)

	Note	Year Ended December 31, 2014	Year Ended December 31, 2013
Cash flows from operating activities			
Earnings (loss)		$ (48,028)	$ 4,914
Adjustments for non-cash items:			
Impairment	12	69,531	-
Depreciation, depletion and amortization		35,846	31,206
Exploration & evaluation		154	-
Unit-based compensation - non-cash portion		(8,294)	3,859
Unrealized risk management loss (gain)		(15,718)	3,675
Loss on disposal of assets		-	303
Finance expense		467	314
		33,958	**44,271**
Changes in working capital:			
Trade and other receivables		1,757	290
Prepaid expenses		140	(62)
Trade and other payables		682	(2,807)
		2,579	(2,579)
Cash generated from operations		36,537	41,692
Abandonment expenditures		(212)	(9)
Income taxes paid		-	-
Net cash generated by operating activities		**$ 36,325**	$ **41,683**
Cash flows from investing activities			
Exploration and evaluation		-	(63)
Oil and gas properties		(24,297)	(30,054)
Property, plant and equipment		(61)	(215)
Acquisition of oil and gas assets	6	(106,319)	(35,855)
Disposition of oil and gas assets	6	150,141	106
Change in non-cash working capital		1,174	-
Net cash generated by (used in) investing activities		**$ 20,638**	**$ (66,081)**
Cash flows from financing activities			
Debt		(30,921)	34,827
Proceeds from issuance of units		17,421	21,032
Trust unit issuance costs		(37)	(111)
Cash distributions to unitholders		(35,287)	(32,191)
Deferred financing charges		(513)	(430)
Change in non-cash working capital		-	(859)
Net cash generated by (used in) financing activities		**$ (49,337)**	**$ 22,268**
Net increase (decrease) in cash and cash equivalents		**7,626**	**(2,130)**
Effects of exchange rates on cash and cash equivalents		2,066	(442)
Cash at beginning of the period		1,435	4,007
Cash at end of the period		**$ 11,127**	**$ 1,435**

The notes are an integral part of these financial statements.

Eagle Energy Trust

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and December 31, 2013
(in Canadian dollars)

1. Reporting entity / Structure of the Trust

Eagle Energy Trust was formed as an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta on July 20, 2010. The beneficiaries of the Trust are the unitholders.

Eagle Energy Trust's activities are restricted to owning property (other than real property or interests in real property), and it does not carry on business.

Throughout these notes to the consolidated financial statements, Eagle Energy Trust and its subsidiaries are referred to collectively as the "Trust" or "Eagle" for purposes of convenience. For a list of subsidiaries and a detailed description of the structure of the Trust, refer to note 5 "Subsidiaries and consolidated entities".

The Trust's subsidiaries completed an internal reorganization on June 16, 2014, pursuant to which the Trust's new indirect U.S. subsidiary, Eagle Hydrocarbons Inc., acquired all of the assets and assumed all of the obligations of Eagle Energy Acquisitions LP and its general partner, Eagle Hydrocarbons LLC. Management and the directors of Eagle Hydrocarbons Inc. are the same individuals as the management and directors of Eagle Hydrocarbons LLC. Eagle Energy Acquisitions LP and Eagle Hydrocarbons LLC were subsequently dissolved at the end of 2014.

The unitholders of the Trust approved a special resolution on December 15, 2014 to amend the investment restrictions in Eagle's Trust indenture. The change enables the Trust to invest in energy assets in Canada through its indirect Canadian subsidiary, Eagle Energy Canada Inc. The strategy of the Trust is to invest in operating subsidiaries that will acquire on-shore petroleum reserves and production in certain regions of Canada and the United States. The Trust's subsidiaries do not intend to engage substantively in exploration activities.

The Trust intends to make monthly distributions of a portion of its available cash to unitholders and use the remainder of its available cash to reinvest in its subsidiaries to fund growth through additional acquisitions and capital expenditures. Cash flow is provided to the Trust from properties owned and operated by the indirectly owned subsidiaries of the Trust, Eagle Hydrocarbons Inc. and Eagle Energy Canada Inc.

The address of the Trust is Suite 2710, 500 - 4th Avenue SW, Calgary, AB, T2P 2V6.

2.1. Basis of preparation

The foreign exchange rate at December 31, 2014 was $US 1 equal to $CA $1.16 (December 31, 2013 - $US 1 equal to $CA 1.06), and the average foreign exchange rate for the year ended December 31, 2014 was $US 1 equal to $CA 1.10 (for the year ended December 31, 2013 - $US 1 equal to $CA 1.03).

Basis of accounting

The consolidated financial statements were authorized for issue in accordance with a resolution of the Board of Directors made on March 19, 2015.

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The preparation of financial statements in conformity with IFRS requires Management to make estimates and assumptions that affect the reported amounts of revenues and expenses during the period, assets and liabilities, and the disclosure of contingent liabilities at the date of the financial statements. The key estimates and assumptions are set out in note 3 "Critical accounting estimates and judgments". Such estimates and assumptions are based on historical experience and various other factors that are believed to be reasonable in the circumstances and constitute Management's best judgment at the date of the financial statements. In the future, actual experience may deviate from these estimates and assumptions. This could affect future financial statements as the original estimates and assumptions are modified, as appropriate, in the year in which the circumstances change.

These financial statements have been prepared on the historical cost basis except for those items which are required to be stated at fair value, which include risk management assets or liabilities and liabilities associated with unit based compensation. Historical cost is generally based on the fair value of the consideration given in exchange for the asset. The principal accounting policies adopted are set out below in note 2.3 "Significant accounting policies".

Basis of consolidation

The consolidated financial statements incorporate the financial statements of the Trust and its subsidiaries up to the balance sheet date. Subsidiaries are all entities over which the Trust has the power to govern the financial and operating policies. Subsidiaries are fully consolidated from the date on which control is transferred and continue to be consolidated until the date that control ceases. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

A list of the subsidiaries has been included in note 5 "Subsidiaries and consolidated entities".

2.2 Changes in accounting policy and disclosures

Historically, the Trust has included crude oil transportation charges as a component of transportation and marketing expenses. Following a review of the Trust's crude oil contracts during the third quarter, it was determined that the criteria for revenue recognition are met at the point of sale before the crude oil is transported by its purchasers and any charges levied by its purchasers past the point of sale should be treated as a reduction of the Trust's revenue rather than as a transportation and marketing expense. Consequently, the Trust has stated its revenue and transportation and marketing expense for the year ended December 31, 2014, and restated its revenue and transportation and marketing expense retroactively for the comparative periods, to reflect this adjustment.

For the year ended December 31, 2014 and December 31, 2013, the impact of the oil transportation adjustment to revenue and transportation and marketing expenses was a $1.8 million and $2.0 million reduction, respectively.

Accounting pronouncements adopted

On January 1, 2014, the Trust adopted International Financial Reporting Interpretations Committee ("IFRIC") Interpretation 21-Levies, which addresses payments to government bodies. There was no material impact to the Trust as a result of adopting the new standard.

IAS 36 - Impairment of Assets - the IASB issued amendments to IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. This amendment is effective for annual periods beginning on or after January 1, 2014.

Accounting pronouncements not yet adopted

IFRS 9, Financial Instruments, replaces International Accounting Standard 39, Financial Instruments: Recognition and Measurement. IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Trust is currently evaluating the impact of adopting IFRS 9 on the consolidated financial statements.

IFRS 15, Revenue from contracts with customers, replaces IAS 18 - Revenue and IAS 11 - Construction contracts and provides a new principle based model on revenue recognition to all contracts with customers. Mandatory adoption is effective for periods beginning on or after January 1, 2017. The Trust is currently evaluating the impact of adopting this standard on the consolidated financial statements.

The Trust will continue to monitor the adoption efforts of industry participants and the efforts of the CICA and industry groups. Additional adjustments to the Trust's accounting policies may be required upon completion of a separate IASB framework for extractive industries.

2.3 Significant accounting policies

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements and have been applied consistently by the Trust and its subsidiaries.

Business combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The consideration transferred in a business combination is measured as the fair value of the assets given, equity instruments issued and liabilities incurred at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the consideration transferred in a business combination over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. Any non-controlling interest or equity interest held which becomes a component of an acquisition is included in the computation of goodwill. If the cost of the acquisition is less than the fair value of the net assets of the subsidiary acquired, the fair value of the net assets is reassessed. Provided the cost remains less than the fair value of the net assets acquired, after reassessment, the difference is recognized in the income statement.

Joint arrangements

Many of the Trust's oil and natural gas activities involve interests in joint arrangements. Joint arrangements are categorized as either joint operations or joint ventures, depending on the rights and obligations of the parties in the arrangement. Joint operations arise when the Trust has rights to the assets and obligations for the liabilities of the arrangement. The consolidated financial statements include the Trust's share of assets, liabilities, revenues and related costs of the joint operation. Joint ventures arise when the Trust has rights to net assets of the arrangement. Joint ventures are accounted for under the equity method.

Foreign currency

Items included in the financial statements of each of the Trust's entities are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The consolidated financial statements are presented in "Canadian dollars" ("$CA"), which is the functional and presentation currency of the Trust.

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at period end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in the income statement. Non-monetary assets that are measured at fair value are translated using the exchange rate at the date that the fair value was determined. Translation differences on equities and similar non-monetary items measured at fair value are recognized in profit or loss, except for differences on available-for-sale non-monetary financial assets such as equity shares, which are included in the fair value reserve in equity unless the asset is a hedged item in a fair value hedge.

The results and financial position of all the Trust entities (none of which has the currency of a hyper-inflationary economy) that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

(a) assets and liabilities for each balance sheet presented are translated at the closing rate at the date of that balance sheet;

(b) income and expenses for each income statement are translated at average exchange rates (unless the average is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions);

(c) all items included in the statement of changes in equity, other than net profit or loss, for the year, are translated at historical exchange rates; and

(d) all resulting exchange differences are recognized as a separate component of equity.

On consolidation, exchange differences arising from the translation of the net investment in foreign entities are taken to unitholders' equity. When a foreign operation is sold and control is lost, such exchange differences are recognized in the income statement as part of the gain or loss on sale.

Where a subsidiary that is a foreign operation repays or partially repays an equity-like loan or returns or partially returns trust unit capital but there is no change in the parent's proportionate percentage of ownership interest, the Trust's chosen accounting policy is that "ownership interest" refers only to the proportionate interest that the parent continues to own. Since the parent would continue to own the same percentage of the subsidiary and continue to control the foreign operation, no change in the parent's proportionate percentage of ownership interest would result and no disposal or partial disposal of ownership interest would occur that would have to be reclassified from the Cumulative Translation Adjustment (CTA) account into income.

Goodwill and fair value adjustments arising on the acquisition of a foreign entity are treated as assets and liabilities of the foreign entity and translated at the closing rate.

Financial instruments

Financial assets and financial liabilities are recognized in the balance sheet when the Trust becomes a party to the contractual provisions of the instrument. The effective interest rate method is a method of calculating the amortized cost of a financial asset or liability and allocating interest income or expense over the relevant period. The effective interest rate is the applicable discount rate for the estimated future cash receipts or payments over the expected life of the financial asset or liability.

A. Non-derivative financial instruments

Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit or loss, any directly attributable transaction costs.

An instrument is classified at fair value through profit or loss if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through profit or loss if the Trust manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Trust's risk management or investment strategy. Upon initial recognition, attributable transaction costs are recognized in profit or loss when incurred. Financial instruments at fair value through profit or loss are measured at fair value and changes therein are recognized in profit or loss.

Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

(a) Financial assets

Financial assets consist predominantly of loans and receivables. The classification depends on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

(i) Loans and receivables

The Trust's loans and receivables comprise cash and trade and other receivables.

Cash is comprised of cash on hand.

Trade and other receivables, which are non-derivative financial assets that have fixed or determinable payments that are not quoted in an active market, are classified as loans and receivables. They are included in current assets, except for those with maturities greater than 12 months after the balance sheet date, which are classified as non-current assets.

Loans and receivables are carried at their amortized cost using the effective interest rate method, net of any impairment. Interest income is recognized by applying the effective interest rate method, except for short-term receivables when the recognition of interest would be immaterial.

(ii) Impairment of financial assets

Financial assets are assessed for impairment at each balance sheet date. Financial assets are considered impaired when there is objective evidence that the estimated future cash flows of the asset have been negatively impacted. For loans and receivables, the amount of the impairment is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate.

In the event of impairment, the carrying amount of the financial asset is reduced by the impairment loss, except for trade receivables where the carrying amount is reduced through the use of an allowance account. When a trade receivable is uncollectible, it is written off against the allowance account, and the amount of the loss is recognized in the income statement. Subsequent recoveries of amounts previously written off are credited against the income statement.

(b) Financial liabilities and equity

Financial liabilities and equity instruments are classified in accordance with IAS 32 "Financial Instruments: Presentation".

(i) Trade payables and distributions payable

Trade payables and distributions payable are recognized initially at fair value and subsequently measured at amortized cost using the effective interest rate method. Interest income is recognized by applying the effective interest rate, except for short-term payables when the recognition of interest would be immaterial.

(ii) Borrowings

Borrowings are recognized initially at fair value net of debt issuance costs in the form of cash payments. Borrowings are subsequently stated at amortized cost, any difference between the proceeds and the redemption value is recognized over the term of the borrowings using the effective interest rate method and charged to the income statement as finance costs.

Borrowing costs incurred for the construction of any qualifying asset are capitalized during the period of time that is required to complete and prepare the asset for its intended use. To the extent that the Trust borrows funds generally and uses them for the purpose of obtaining a qualifying asset, the Trust determines the amount of borrowing costs eligible for capitalization by applying a capitalization rate to the expenditures on that asset. The capitalization rate is the weighted average of the borrowing costs applicable to the borrowings of the Trust that are outstanding during the period, other than borrowings made specifically for the purpose of obtaining a qualifying asset. The amount of borrowing costs that the Trust capitalizes during a period shall not exceed the amount of borrowing costs it incurred during that period. For funds borrowed specifically to obtain a qualifying asset, the borrowing costs eligible for capitalization are the actual borrowing costs incurred during the period less any investment income earned from the temporary investment of the borrowed funds.

All other borrowing costs are recognized in profit or loss using the effective interest method.

Where an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as derecognition of the original liability and recognition of a new liability. The difference between the carrying amounts of the original liability and the fair value of the new liability is recognized in the income statement.

Borrowings are classified as current liabilities unless the Trust has an unconditional right and the intent to defer settlement of the liability for at least 12 months after the balance sheet date.

(iii) Equity instruments

An equity instrument is any contract that evidences a residual interest in the assets of the Trust after deducting all of its liabilities. Equity instruments of the Trust are recorded at the proceeds received, net of incremental costs directly attributable to the issue of new Trust units or options, which are shown as a deduction, net of tax, from the proceeds. Trust units are classified as equity.

(iv) Compound instruments

The exceptions in IAS 32 which allow an entity such as a trust to classify “puttable” instruments as equity do not extend to instruments such as warrants, options and convertible debt that entitle the holder to acquire “puttable” instruments for a fixed price. Such instruments are classified as liabilities in their entirety under IAS 32.22A. Because of the “puttable” nature of trust units, there will always be an embedded derivative and the instrument shown as a liability.

B. Derivative financial instruments

The Trust enters into certain financial derivative contracts periodically in order to manage its exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Trust does not designate its financial derivative contracts as effective accounting hedges and thus does not apply hedge accounting (even though the Trust considers all commodity contracts to be economic hedges). As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the balance sheet at fair value. Related transaction costs are recognized in profit or loss when incurred.

The Trust may enter into forward physical delivery sales contracts. The policy is to account for these forward physical delivery sales contracts, which are entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements, as executory contracts. As such, these contracts are not considered to be derivative financial instruments and will not be recorded at fair value on the balance sheet. Settlements on these physical sales contracts would be recognized in revenue.

Embedded derivatives are separated from the host contract and accounted for separately if: (i) the economic characteristics and risks of the host contract and the embedded derivative are not closely related; (ii) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and (iii) the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in profit or loss.

(a) Fair Value Hierarchy

To estimate fair value of derivatives, the Trust uses quoted market prices when available, or third-party models and valuation methodologies that utilize observable market data. In addition to market information, the Trust incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The Trust characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities. *Active markets* are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace.

Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. In forming estimates, the Trust utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement.

Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell. Non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification. Oil and gas properties, property, plant and equipment and intangible assets once classified as held for sale are not depreciated.

Exploration and evaluation expenditures

In line with IFRS 6, pre-license costs, defined as those costs incurred before the legal right to explore has been acquired, are expensed in the period in which they are incurred. Exploration and evaluation costs of a type that are not sufficiently closely related to a specific resource to support capitalization are also expensed in the period in which they are incurred.

Exploration and evaluation costs associated with oil and gas exploration and investments are capitalized on a project by project basis (well, field or specific exploration licenses, as appropriate), pending determination of the technical feasibility and commercial viability of the project. Costs incurred include appropriate technical (geological and geophysical, or "G & G"), license acquisition and directly attributable operational overhead. Amounts recorded for these assets represent costs and are not intended to reflect present or future values.

The recoverability of all exploration and evaluation expenditures is dependent upon the discovery of economically recoverable reserves and future profitable production or proceeds from the disposition thereof. When proved plus probable reserves are assigned, the accumulated costs for the relevant area are tested for impairment and transferred from exploration and evaluation assets to oil and gas properties and further classified as either "Developed Oil and Gas Assets" or "Production Facilities and Equipment" (tangible fixed assets), as appropriate.

Oil and gas properties

The drilling of development wells (including unsuccessful development or delineation wells) as well as expenditures on the construction, installation or completion of infrastructure facilities such as pipelines are capitalized within oil and gas properties. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Within oil and gas properties, developed oil and gas assets and production facilities and equipment (tangible fixed assets) are stated at cost less accumulated depletion, depreciation and amortization along with accumulated impairment losses. When significant parts of an item of oil and gas properties have different useful lives, they are accounted for as separate items (componentized) and depreciated at that level.

The cost of oil and gas properties is amortized over total estimated proven and probable reserves using the unit-of-production method. Costs are amortized only once commercial reserves associated with a development project can be determined and commercial production has commenced.

The unit-of-production rate is calculated by reference to the ratio of production volumes during the period to the related proven and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves.

Changes in factors such as estimates of proven and probable commercial reserves that affect unit-of-production calculations do not give rise to prior financial period adjustments and are dealt with on a prospective basis.

Impairment - Exploration and evaluation expenditures

Exploration and evaluation assets are assessed for impairment if:

(i) sufficient data exists to determine technical feasibility and commercial viability; or

(ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

Sufficient data is considered to exist in order to determine the technical feasibility and commercial viability of extracting a resource when proved plus probable reserves are assigned. A review for indicators of impairment on a project by project basis (well, field or specific exploration licenses, as appropriate) is carried out, at least annually, to ascertain whether proved plus probable reserves have been assigned. If proved plus probable reserves have been assigned, exploration and evaluation assets attributable to those reserves are first tested for impairment (and any resulting impairment loss is recognized) and then reclassified from exploration and evaluation assets to oil and gas properties and amortized over the estimated life of the proven and probable reserves on a unit-of-production basis.

Exploration and evaluation costs for which technical feasibility has not yet been determined through the assignment of proved plus probable reserves are subject to technical, commercial and management review for indicators of impairment at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this intent no longer exists, such facts and circumstances might indicate that the carrying amount exceeds the recoverable amount. If this is the case, the costs are expensed. Costs associated with an exploratory dry hole are expensed immediately if commercially viable quantities of hydrocarbons are not found. Where a license is relinquished or project abandoned, the related costs are expensed. Where the Trust maintains an interest in a project, but the value of the project is considered to be impaired, a provision against the relevant capitalized costs will be provided.

For purposes of impairment testing, exploration and evaluation assets are allocated and added to the carrying amount of any oil and gas properties in the same cash-generating unit (“CGU”) and the combined carrying amount is tested for impairment by comparing the carrying amount to the recoverable amount.

Impairment – Oil and gas properties

Oil and gas properties (which are further classified as developed oil and gas assets and production facilities and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Oil and gas properties are grouped into CGUs for impairment testing. At this time, the Trust has grouped its oil and gas properties into three CGUs: the Salt Flat properties, the Hardeman properties, and the Dixonville properties. An impairment loss is recognized for the amount by which the asset’s or CGU’s carrying amount exceeds its recoverable amount. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to dispose. In determining fair value less costs to dispose, the Trust will consider recent transactions within the industry, long-term views of commodity prices, externally evaluated reserves volumes and discount rates specific to the CGU.

Decommissioning provision

Provision is made for the present value of the future cost of abandonment (dismantling, decommissioning, and site disturbance remediation activities) of oil and gas wells and related facilities using an appropriate risk-free rate. This provision is recognized when the legal or constructive obligation to abandon arises. The estimated costs, based upon engineering cost levels prevailing at the balance sheet date, are computed on the basis of the latest assumptions as to the scope and method of abandonment. The corresponding amount is capitalized as part of exploration and evaluation assets or oil and gas properties and is amortized on a unit-of-production basis as part of the depreciation, depletion and amortization charge.

The increase in the provision due to the passage of time (“accretion”) is treated as a component of finance costs.

Any adjustment to the provision arising from reassessment of the estimated cost of decommissioning are added to, or deducted from, the cost of the related asset in the current period. If a decrease in the liability exceeds the carrying amount of the asset, the excess is recognized immediately in profit or loss.

Property, plant and equipment

Property, plant and equipment is composed of non-oil and gas assets and is stated in the balance sheet at cost, less accumulated depreciation and any provision for impairment.

The initial cost of an asset comprises its purchase price or construction cost and any costs directly attributable to bringing the asset into operation. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Property, plant and equipment is depreciated on a straight line basis at rates sufficient to write off the cost, less estimated residual values, of individual assets over their estimated useful lives, as follows:

Improvements to leasehold property	2-10 years (or over the remaining life of the lease if shorter)
Office furniture, fixtures and equipment	3 years
Computer equipment	2 years
Vehicles	5 years

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each balance sheet date.

Revenue recognition

Revenue is comprised of the fair value of the consideration received or receivable for the sale of hydrocarbons in the ordinary course of the Trust's activities. Intercompany sales are eliminated during consolidation. With respect to royalties, the Trust is acting as a collection agent on behalf of others.

Revenue is recognized when the amount can be reliably measured, it is probable that future economic benefits will flow to the Trust, and when specific criteria have been met as described below. The amount of revenue is not considered to be reliably measurable until all contingencies relating to the sale have been resolved. The Trust bases its estimates on historical results, taking into consideration the type of customer, the type of transaction, the nature of the product and the specifics of each arrangement.

Revenues from the sale of crude oil and natural gas sales are recognized when the significant risks of loss and rewards of ownership have transferred i.e., when legal title passes to the third-party purchaser. This is generally at the time the product enters collection facilities or pipeline facilities. The Trust uses the entitlement method to account for revenue whereby revenue recognition is based upon the Trust's direct ownership interest in the underlying oil and gas properties.

Costs associated with the sale of crude oil, natural gas liquids and natural gas such as taxes and field operating expenses are reflected individually.

Unit-based compensation

The Trust uses the fair value method of valuing compensation expense associated with the Trust's unit option plan. The units issued pursuant to the option plan are not considered equity settled stock-based compensation since the IAS 32 "puttable instrument exemption" does not extend to unit-based payments made by a Trust. Therefore, options issued subject to the option plan are treated similar to a cash settled stock-based compensation arrangement, with the associated liability being fair-valued at the end of each reporting period and the corresponding change to fair value being recognized in the income statement.

The Trust has established other unit-based compensation plans whereby cash settled notional units are granted to employees. The fair value of these notional units is estimated and recorded as a cash settled unit-based compensation arrangement. The offsetting amount is recorded as accrued liabilities or other long-term liabilities. A realization of the expense and a resulting reduction in cash provided by operating activities occurs when a cash payment is made.

Finance income and expense

Finance expense comprises interest expense on borrowings, amortization of deferred financing costs, bank fees, and accretion of the discount on the decommissioning provision.

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

Unitholder distributions

Unitholder distributions are declared and paid monthly. Unitholders' equity is reduced by the amount of the declared distribution at the record date.

Taxation

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity. Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Tax on income in interim periods is accrued using the tax rate that would be applicable to expected total annual earnings.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. The effect of any change in income tax rates is recognized in the current period income. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

The Trust is a “mutual fund trust” within the meaning of the Income Tax Act (Canada) (the "Tax Act"). On December 15, 2014, the holders of the Trust units (the "Unitholders") approved a special resolution to amend the investment restrictions contained in the trust indenture governing the Trust. The amendment broadens the investment powers of the Trust, including permitting the Trust, through its subsidiaries, to invest in Canadian energy assets. As a consequence of the investment by one of the Trust's Canadian subsidiaries (Eagle Energy Canada Inc.) in Canadian oil and gas assets on December 18, 2014, the Trust became a "SIFT trust" within the meaning of the Tax Act.

As a SIFT trust, the Trust is taxable only on income that: (i) constitutes "non-portfolio earnings" (within the meaning of the Tax Act); or (ii) is not distributed or distributable to the Unitholders. The Trust's indirect Canadian investment on December 18, 2014 is not anticipated to give rise to any "non-portfolio earnings" since the only income the Trust is expected to receive from the Canadian operations will be in the form of returns of capital or taxable dividends from its Canadian subsidiary. As taxable dividends are paid out of the subsidiary's after-tax corporate income, SIFT tax is not anticipated to apply to the Trust or its affiliates (consistent with the policy behind the SIFT tax regime). The Trust has distributed and will continue to distribute all of its taxable income to the Unitholders. As a consequence, it is not anticipated that the Trust will be subject to any Canadian federal income tax.

As the Trust now holds “taxable Canadian property” (as defined in the Tax Act) it is subject to certain limits on non-resident ownership, and the trust indenture provides certain powers to the trustee in relation thereto.

The Trust's indirect Canadian subsidiary is in the business of acquiring, developing and producing oil and natural gas reserves in Canada. Canadian corporate subsidiaries of the Trust that own Canadian oil and gas assets will be taxed in the same manner as other Canadian oil and gas corporations, including being subject to Canadian federal income tax to the extent that taxable income cannot be reduced by claiming permitted deductions (such as wages and other employment expenses, interest payments, various Canadian resource expenditures and certain capital expenditures). It is anticipated that the Trust’s Canadian corporate subsidiaries, like many Canadian petroleum exploration and production companies, will maximize available deductions in order to minimize corporate tax. The Trust expects that the after-tax cash flow of any Canadian subsidiary will be distributed to the Trust by way of returns of capital and taxable dividends. As such, any income tax borne by a corporate subsidiary will reduce the amount available for distribution to Unitholders.

The Trust’s indirect US subsidiary is in the business of acquiring, developing and producing oil and natural gas reserves in the United States. As a general rule, a foreign corporation engaged in a United States trade or business is subject to U.S. federal income tax on income that is effectively connected (effectively connected income, or “ECI”) with the United States trade or business and, if an income tax treaty with the United States applies, is attributable to a permanent establishment maintained by the foreign corporation in the United States. ECI is subject to United States federal income tax on a net basis at the regular United States federal graduated rates of tax that apply to United States persons. A foreign corporation’s taxable income is computed by claiming deductions that are attributable to the effectively connected gross income on a timely filed return. A foreign corporation that derives ECI is generally required to make quarterly payments of estimated United States tax, and is required to file a United States federal income tax return. Eagle Hydrocarbons Inc. deducts interest paid on certain intercompany notes and other deductible expenses, including intangible drilling and developments costs and depletion in calculating its US taxable income.

Trust unit calculations

The Trust uses the treasury stock method to determine the dilutive effect of Trust unit options. Under the treasury stock method, outstanding and exercisable instruments that will have a dilutive effect are included in per-unit diluted calculations, ordered from most dilutive to least dilutive.

The dilutive effect of convertible obligations or instruments is determined using the "if-converted" method, whereby the outstanding convertibles at the end of the period are assumed to have been converted at the beginning of the period or at the time of issue if issued during the period. Amounts charged to income or loss which relate to the outstanding convertibles are added back to net income for the diluted calculation. The units issued upon conversion are included in the denominator of per-unit basic calculations from the date of issue.

3. Critical accounting estimates and judgments

The Trust makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. Such estimates and assumptions are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Estimation of oil and natural gas reserves

Oil and natural gas reserves are the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of oil and natural gas reserves are inherently imprecise, require the application of judgment and are subject to future revision. Accordingly, financial and accounting measures (such as fair value less costs to dispose of property, plant and equipment for the impairment calculation, depletion, and decommissioning provisions) that are based on reserves are also subject to change.

Capitalized exploration and evaluation expenditures

In making decisions about whether to continue to capitalize exploration and evaluation expenditures, it is necessary to make judgments about the commercial reserves and the level of activities that constitute on-going evaluation determination. If there is a change in any judgment in a subsequent period, then the related capitalized exploration and evaluation expenditure would be expensed in that period, resulting in a charge to income.

Business combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The consideration transferred in a business combination is measured as the fair value of the assets given, equity instruments issued and liabilities incurred at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the consideration transferred in a business combination over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. Any non-controlling interest or equity interest held which becomes a component of an acquisition is included in the computation of goodwill. If the cost of the acquisition is less than the fair value of the net assets of the subsidiary acquired, the fair value of the net assets is reassessed. Provided the cost remains less than the fair value of the net assets acquired, after reassessment, the difference is recognized in the income statement.

Decommissioning provision

Estimates of the amounts of provision for decommissioning recognized are based on current legal and constructive requirements, technology and price levels. As actual outflows may be different from estimates due to changes in laws, regulations, technology, prices, and conditions, and can take place in the future, the carrying amounts of provisions are regularly reviewed and adjusted to take account of such changes. The Trust has interpreted the accounting standard to use the risk-free discount rate for calculating the present value of the decommissioning obligation.

Impairment of property, plant and equipment

The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to dispose. These calculations require the use of estimates and assumptions. It is reasonably possible that the commodity price assumption may change, which may impact the estimated life of the asset and may require a material adjustment to the carrying value of assets. The Trust monitors recent transactions within the industry, long-term views of commodity prices, externally evaluated reserves volumes and discount rates specific to the CGU.

Income taxes

The Trust recognizes the net future tax benefit related to deferred income tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred income tax assets requires the Trust to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Trust to realize the net deferred tax assets recorded at the balance sheet date could be impacted.

Additionally, future changes in tax laws in the jurisdiction in which the Trust operates could limit the ability of the Trust to obtain tax deductions in future periods.

Derivative financial instruments

As described in note 4 “Financial risk management”, derivative financial instruments are used by the Trust to manage its exposure to market risks relating to commodity prices. The Trust’s policy is not to use derivative financial instruments for speculative purposes. Derivative financial instruments that do not qualify, or are not designated, as hedges for accounting are recorded at fair value. Instruments are recorded in the balance sheet as either an asset or a liability with changes in fair value recognized in the income statement. The estimate of fair value of all derivative instruments is based on quoted market prices, or in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Classification of Trust units as equity

Trust units issued by the Trust give the holder the right to put the units back to the issuer in exchange for cash. IAS 32 “Financial Instruments: Presentation” establishes the general principle that an instrument which gives the holder the right to put the instrument back to the issuer for cash should be classified as a financial liability, unless such instrument has all of the features and meets the conditions of the IAS 32 “puttable instrument exemption”. If these “puttable instrument exemption” criteria are met, the instrument is classified as equity. The Trust has examined the terms and conditions of its Trust Indenture and classifies its outstanding Trust units as equity because the Trust units meet the “puttable instrument exemption” criteria as there is no contractual obligation to distribute cash.

Contingencies

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

Unit Based Compensation

The amount of compensation expense accrued for compensation arrangements is subject to Management’s best estimate of whether or not the performance criteria will be met and what the ultimate payout will be. Certain obligations for payments under the compensation plans are measured at fair value and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on several assumptions including the risk-free interest rate and the expected volatility of the unit price and therefore is subject to measurement uncertainty.

4. Financial risk management

The Trust’s activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Trust finances its operations through a combination of cash, loans from banks (lines of credit) and trust unit equity. Finance requirements such as equity, debt, and project finance are reviewed by the Board when funds are required for acquisition, exploration, and development projects.

The Trust's treasury management function is responsible for managing funding requirements and investments which include banking and cash flow management. Interest and foreign exchange exposure are key functions of treasury management to ensure adequate liquidity at all times to meet cash requirements.

The principal financial instruments of the Trust are cash held in banks, trade receivables, distributions payable, debt, and risk management contracts. These instruments are for the purpose of meeting its requirements for operations.

Credit risk

Credit risk is the risk of financial loss to the Trust if a customer, joint venture partner or counterparty to a financial instrument fails to meet its contractual obligations. It arises principally from the Trust's receivables from its product marketer and joint venture partners. The maximum exposure to credit risk was as follows:

$000's		**December 31, 2014**		December 31, 2013
Cash	$	11,127	$	1,435
Trade and other receivables		6,669		7,826
Risk management asset		14,919		-
	$	**32,715**	$	9,261

Cash

The Trust limits its exposure to credit risk by investing only in liquid securities and only with counterparties with a strong credit rating. Additionally, the Trust enters into certain risk management contracts periodically to economically hedge a portion of its oil and natural gas sales. Given this approach, Management does not expect any counterparty to fail to meet its obligations as at December 31, 2014.

Trade and other receivables

The Trust's operations are conducted in Canada and the United States. Exposure to credit risk is primarily influenced by the individual characteristics of each customer.

Receivables from the Trust's product marketers are normally collected in the month following production. The Trust's policy to mitigate credit risk associated with these balances is to establish marketing relationships with reputable purchasers with good credit. The Trust historically has not experienced collection issues with its marketers. The Trust does not typically obtain collateral from its marketers.

Joint venture receivables are with customers in the oil and gas industry and are subject to normal industry credit risks. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. In certain circumstances, the Trust may request an operating advance or cash call a partner in advance of capital expenditures being incurred. With respect to receivables related to non-operated properties, provisions in the joint operating agreement allow the Trust to assume operatorship in certain circumstances.

The Trust does not anticipate any default as it transacts with creditworthy customers and Management does not expect any losses from non-performance by these customers. As such, no provision for doubtful accounts has been recorded at December 31, 2014 and December 31, 2013.

Risk management asset

The Trust enters into certain risk management contracts periodically to economically hedge a portion of its oil and natural gas sales and manage its foreign exchange exposure. The counterparties to these instruments are highly rated corporate, investment banking, and capital markets groups. See "Market risk" and "Commodity price risk" for further discussion regarding these risk management contracts.

The maximum exposure to credit risk for loans and receivables at the reporting dates by type of customer was:

$000's	December 31, 2014	December 31, 2013
Oil and natural gas marketing companies	$ 4,978	$ 6,458
Receivable from joint venture working interest owners	1,388	1,158
Other	303	210
	$ 6,669	$ 7,826

The Trust's most significant customers are two US oil and natural gas marketers and account for approximately 75% or $5.0 million of trade receivables at December 31, 2014 and approximately 83% or $6.5 million at December 31, 2013. Additionally, 21% or $1.4 million represents billed and accrued receivables from joint venture working interest partners at December 31, 2014 and 15% or $1.2 million at December 31, 2013. As of December 31, 2014 and December 31, 2013, substantially all of the receivables were considered current (less than 90 days old) and none were considered impaired.

Liquidity risk

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

At December 31, 2014, the Trust had a working capital surplus, excluding the risk management asset, of approximately $8.9 million and a $81.2 million ($US 70.0 million) Canadian dollar equivalent authorized credit facility. At December 31, 2014, $34.0 million ($US 29.3 million) credit was available under the facility. See note 17 "Debt". To better manage its liquidity risk, the Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures ("AFEs") on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil and natural gas revenue each month.

The following are the contractual undiscounted maturities of financial liabilities, including estimated interest payments, as applicable, at December 31, 2014:

$ 000's	Carrying amount	Contractual cash flows	Less than one year	One – two years	Two – five years	More than five years
Trade and other payables	$ 8,316	$ 8,316	$ 8,316	$ -	-	-
Distributions payable	1,068	1,068	1,068	-	-	-
Debt	47,200	47,200	-	47,200	-	-
Interest	-	2,842	-	2,842		
	$ 56,584	**$ 59,246**	**$ 9,384**	**$ 50,042**	-	-

Contractual cash flows at December 31, 2014 exclude the current portion of unit-based compensation of $1,336,016.

The following were the contractual undiscounted maturities of financial liabilities, including estimated interest payments, as applicable, at December 31, 2013:

$ 000's	Carrying amount	Contractual cash flows	Less than one year	One – two years	Two – five years	More than five years
Trade and other payables	$ 5,929	$ 5,929	$ 5,929	$ -	-	-
Distributions payable	2,813	2,813	2,813	-	-	-
Risk management liability	1,453	1,453	1,453	-	-	-
Current debt	10,636	10,695	10,695		-	-
Long-term debt	67,485	67,485	-	67,485	-	-
Interest	2,082	2,082	59	2,023		
	$ 90,398	$ 90,398	$ 19,496	$ 69,508	-	-

Contractual cashflows at December 31, 2013 exclude the current portion of unit-based compensation of $10,025,021.

The Trust units contain a redemption feature, see note 18 “Trust capital”. Utilizing the terms of redemption as outlined in note 18, the total market redemption price for all outstanding units at December 31, 2014 would be $81,624,880 ($2.59 per unit 10 day volume weighted average price x 90% x 35,017,112 units); and $229,446,764 ($7.93 per unit 10 day volume weighted average price x 90% x 32,148,909 units) at December 31, 2013. As the maximum cash outlay required by the Trust is capped at $100,000 per month or $1,200,000 per year, the Trust would have approximately 68 years to pay out this commitment (191 years at December 31, 2013).

Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Trust’s income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters while optimizing the return.

The Trust may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand.

The Trust enters into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Trust does not apply hedge accounting for these contracts. The Trust’s production is either sold using “spot” or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price or by way of fixed term, fixed price marketing contracts.

Summary of Unrealized Risk Management Position

As at December 31, 2014, the Trust has entered into the following financial contracts to mitigate the effects of fluctuating prices on a portion of its production:

Oil Fixed Price	***Volume***	***Measure***	***Beginning***	***Term***	***Floor $US***	***Ceiling $US***		***Current fair value $000’s $CA***	***Non-current fair value $000’s $CA***
NYMEX (i)	190	bbls/d	Jan-15	Dec-15	85.40	85.40		2,332	-
NYMEX (ii)	1,000	bbls/d	Jan-15	Jun-15	90.10	92.00		7,317	-
NYMEX (i)	400	bbls/d	Jul-15	Dec-15	87.90	87.90		2,267	-
NYMEX (ii)	400	bbls/d	Jan-15	Jun-15	90.50	94.35		3,003	-
Commodity - unrealized risk management asset							**$**	**14,919**	**-**

(i) Represents a fixed price financial swap transaction with a set forward sale price (WTI reference prices).
(ii) Represents costless collar transaction created by buying puts and selling calls (WTI reference prices).

As at December 31, 2013, the Trust had entered into the following financial contracts to mitigate the effects of fluctuating prices on a portion of its production:

	Volume	***Measure***	***Beginning***	***Term***	***Floor $US***	***Ceiling $US***		***Current fair value $000’s CA***	***Non-current fair value $000’s $CA***
Oil Fixed Price									
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	98.00	98.00		374	-
NYMEX (i)	500	bbls/d	Jan-14	Dec-14	91.15	91.15		(860)	-
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	91.15	91.15		(688)	-
NYMEX (ii)	250	bbls/d	Jan-14	Dec-14	90.00	94.95		(237)	-
NYMEX (ii)	100	bbls/d	Jan-14	Dec-14	93.00	95.35		(42)	-
Commodity - unrealized risk management asset							$	(1,453)	-

(i) Represents costless collar transactions created by buying puts and selling calls (WTI reference prices).
(ii) Represents a fixed price financial swap transaction with a set forward sale price (WTI reference prices).

Reconciliation of Net Risk Management Position

	December 31, 2014				December 31, 2013			
$000's		Fair value		Total net risk management asset (liability)		Fair value		Total net risk management asset (liability)
Fair value of contracts, beginning of year	$	(1,453)	$	(1,453)	$	2,191	$	2,191
Fair value of contracts realized during the period		149		149		(528)		(528)
Fair value of contracts unrealized during the period		15,718		15,718		(3,675)		(3,675)
Effects of exchange rate		505		505		559		559
Fair value of contracts	**$**	**14,919**	**$**	**14,919**	$	(1,453)	$	(1,453)

The total net fair value of Eagle's risk management positions at December 31, 2014 is an asset of $14.9 million (December 31, 2013 - $1.5 million liability) and has been calculated using both quoted prices in active markets and observable market-corroborated data consistent with a Level 2 valuation.

As at December 31, 2014, there were no unrealized foreign exchange contracts outstanding.

Earnings Impact of Realized and Unrealized Risk Management Gain (Loss)

	December 31, 2014						December 31, 2013					
$000's		Realized gain (loss)		Unrealized gain (loss)		Total net gain (loss)		Realized gain (loss)		Unrealized gain (loss)		Total net gain (loss)
Net effect - commodity	**$**	302	**$**	15,718	**$**	16,020	$	(528)	$	(3,675)	$	(4,203)
Net effect - foreign exchange		(153)		-		(153)		-		-		-
Net effect - risk management		**148**		**15,718**		**15,867**		(528)		(3,675)		(4,203)

A 10% increase (decrease) in the market price of crude oil from its 2014 year average of $US 93.00 WTI would have increased (decreased) income by approximately $1.9 million based on the risk management instruments outstanding at December 31, 2014. A 10% increase (decrease) in the market price of crude oil from its 2013 year average of $US 97.98 WTI would have increased (decreased) income by approximately $2.0 million in 2013. This analysis assumes that all other variables remain constant.

Foreign exchange risk

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. Since the acquisition of the Canadian Dixonville property was not effective until January 1, 2015, the Trust's operating cash flows during 2014 were entirely generated in US dollars while distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust's treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil are determined in global markets and generally denominated in US dollars. Generally an increase in the value of the $CA as compared to the $US will reduce the Canadian dollar equivalent prices received by the Trust for its petroleum and natural gas sales in the U.S. but will also reduce the Canadian dollar equivalent operating expenses associated with those sales.

The following financial instruments were denominated in U.S. dollars:

As at December 31, 2014 ($ 000's)		$US		$CA
Cash	$	7,824	$	9,077
Trade and other receivables		5,488		6,366
Trade and other payables		(6,009)		(6,971)
Risk management asset		12,860		14,919
	$	**20,163**	**$**	**23,391**

The average exchange rate during the year ended December 31, 2014 was $US 1 equal to $CA 1.10, and the exchange rate at December 31, 2014 was $US 1 equal to $CA 1.16.

A 10% strengthening (weakening) of the Canadian dollar against the US dollar from its 2014 year average of $CA 1.10 ($US 0.90) would have decreased (increased) income by approximately $2.6 million. This analysis assumes that all other variables remain constant.

As at December 31, 2013 ($ 000's)		$US		$CA
Cash	$	23	$	24
Trade and other receivables		7,160		7,615
Trade and other payables		(4,593)		(4,885)
Risk management liability		(1,366)		(1,453)
Current debt		(10,000)		(10,636)
Long-term debt		(63,450)		(67,485)
	$	**(72,226)**	**$**	**(76,820)**

The average exchange rate during the period ending December 31, 2013 was $US 1 equal to $CA 1.03, and the exchange rate at December 31, 2013 was $US 1 equal to $CA 1.06.

A 10% strengthening (weakening) in the Canadian dollar against the US dollar at December 31, 2013 of $CA 1.03 ($US 0.97) would have decreased (increased) income by approximately $1.0 million. This analysis assumes that all other variables remain constant.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. As at December 31, 2014, $47.2 million ($US 40.7 million) had been drawn against the revolving $81.2 million ($US 70 million) credit facility. Borrowings are by way of Banker's Acceptance (BA's) and prime rate loans. The carrying value of the Trust's debt outstanding on its revolving credit facility approximates its fair value and is consistent with a Level 2 valuation. See note 17 "Debt". At December 31, 2014 and December 31, 2013, there were no covenant violations to the loan agreement.

A 1% increase (decrease) in the interest rate would have decreased (increased) income by approximately $0.6 million based on an average outstanding total debt balance of $57.5 million for the period ended December 31, 2014. A 1% increase (decrease) in the interest rate would have decreased (increased) income by approximately $0.5 million based on an average outstanding total debt balance of $53.1 million for the period ended December 31, 2013.

Capital management

The Trust's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Trust manages its capital structure and makes adjustments to it based upon economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include working capital, loans and borrowing, and unitholders' equity. In order to maintain or adjust the capital structure, the Trust may issue units, engage in external debt financing, and adjust its capital spending to manage current and projected debt levels. The Trust monitors capital based on the ratio of external debt to cash generated from operations. This ratio is calculated as external debt, defined as outstanding loans and borrowings, plus or minus working capital deficit or surplus divided by annualized cash generated from operations before changes in non-cash working capital. Management's objective is to maintain an external debt to estimated future annual cash flow ratio below 2.0. This ratio may increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Trust prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at December 31, 2014, the Trust's ratio of external debt to annualized cash flow was within the range targeted by the Trust.

There were no changes in the Trust's approach to capital management during the period.

Draws against the existing credit facility are subject to established covenants. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves. See note 17 "Debt".

5. Subsidiaries and consolidated entities

The following table summarizes the structure of the Trust. All subsidiaries of the Trust are directly or indirectly wholly-owned by the Trust.

Subsidiary	Country of Formation	Nature of Business	Footnotes
1857515 Alberta Ltd.	Canada	Alberta Corporation	(1)
Eagle Energy Canada Inc.	Canada	Alberta Corporation	(2)
Eagle Energy Holdings Inc.	Canada	Alberta Corporation	(3)
Eagle Hydrocarbons Inc.	United States	Delaware Corporation	(4)
Eagle Energy Commercial Trust	Canada	Alberta Trust	(5)
Eagle Energy Acquisitions LP	United States	Delaware Limited Partnership	(6)
Eagle Hydrocarbons LLC	United States	Delaware Limited Liability Company	(7)

(1) 1857515 Alberta Ltd. is an Alberta Corporation incorporated under the laws of the Province of Alberta on October 31, 2014. 1857515 Alberta Ltd. was created to acquire and hold a 100% interest in Eagle Energy Canada Inc.

(2) Eagle Energy Canada Inc. is an Alberta Corporation incorporated under the laws of the Province of Alberta on October 31, 2014. Eagle Energy Canada Inc. was formed with a general mandate to engage in the business of acquiring, developing, and producing oil and natural gas reserves in Canada.

(3) Eagle Energy Holdings Inc. is an Alberta Corporation incorporated under the laws of the Province of Alberta on May 28, 2014. Eagle Energy Holdings Inc. was created to acquire and hold a 100% interest in Eagle Hydrocarbons Inc.

(4) Eagle Hydrocarbons Inc. is a Delaware corporation incorporated on May 28, 2014. Eagle Hydrocarbons Inc. was formed with a general mandate to engage in the business of acquiring, developing, and producing oil and natural gas reserves in the United States.

(5) Eagle Energy Commercial Trust, an unincorporated open ended trust established under the laws of the Province of Alberta on September 28, 2010, was formed by way of a trust indenture. All outstanding Eagle Energy Commercial Trust Units are owned by the Trust. Eagle Energy Commercial Trust units are issued only when fully paid in money, property or past services and are not subject to future calls or assessments. Eagle Energy Commercial Trust was created to acquire and hold a 99.999% interest in Eagle Energy Acquisitions LP.

(6) Eagle Energy Acquisitions LP, a limited partnership, was created on September 28, 2010 by Eagle Energy Commercial Trust by way of a certificate of limited partnership. Eagle Energy Acquisitions LP was a limited partnership formed under the laws of the State of Delaware with a general mandate to engage in the business of acquiring, developing, and producing oil and natural gas reserves in the United States. Pursuant to the internal reorganization completed on June 16, 2014, Eagle Energy Acquisitions LP transferred all of its assets and liabilities to Eagle Hydrocarbons Inc. Eagle Energy Acquisitions LP was dissolved on December 30, 2014.

(7) Eagle Hydrocarbons LLC was formed on September 28, 2010 to be the general partner of, and acquire and hold the remaining 0.001% interest in, Eagle Energy Acquisitions LP. Eagle Hydrocarbons LLC was a limited liability company formed under the laws of the State of Delaware. Pursuant to the internal reorganization completed on June 16, 2014, Eagle Hydrocarbons LLC transferred all of its assets and liabilities to Eagle Hydrocarbons Inc. Eagle Hydrocarbons LLC was dissolved on December 31, 2014.

The results of the above subsidiaries, together with Eagle Energy Inc. (as further described below) have been included in the consolidated financial statements in accordance with IFRS 10 - Consolidation. All of the entities have December 31 year ends.

Eagle Energy Inc. is the Administrator of the Trust and was formed under the laws of the Province of Alberta on March 28, 2008. The sole shareholder of Eagle Energy Inc. is EEI Holdings Inc. and the sole shareholder of EEI Holdings Inc. is Richard Clark, President, Chief Executive Officer and a director of the Administrator. Eagle Energy Inc. is not a legal subsidiary of the Trust.

EEI Holdings Inc., the sole shareholder of Eagle Energy Inc., has entered into a voting agreement which entitles unitholders of the Trust to elect 100% of the directors of Eagle Energy Inc. EEI Holdings Inc. has also waived certain shareholder rights, including the right to appoint an auditor, dissent rights, and oppression rights. Eagle Energy Inc. is therefore controlled exclusively by the unitholders of the Trust.

Computershare Trust Company of Canada, the Trustee of Eagle Energy Trust, has delegated much of the responsibility for conducting the Trust's affairs to the Administrator, Eagle Energy Inc., pursuant to an administrative services agreement. The Board of Directors of the Administrator therefore performs the majority of the oversight and governance role for the Trust. As Trust Administrator, Eagle Energy Inc. performs services pursuant to the administrative services agreement on a cost recovery basis and no additional fees are payable by the Trust to the Administrator.

Eagle Energy Inc. is a structured entity that has been designated so that voting or similar rights are not the dominant factor in deciding who controls the entity. The relevant activities of Eagle Energy Inc. are directed by means of contractual arrangements. These contractual arrangements give the Trust the current ability to direct the relevant activities of Eagle Energy Inc. As such, Eagle Energy Inc. has been consolidated in these financial statements.

6. Business combinations

At December 31, 2014, Eagle's business combinations consisted of the following:

Property acquisitions

Dixonville property

On December 18, 2014, (with an effective date of January 1, 2015) the Trust's newly established Canadian operating subsidiary, Eagle Energy Canada Inc. acquired a 50% non-operated working interest in producing properties in the Dixonville Montney "C" oil pool located in north central Alberta for cash consideration of $100.9 million, which includes preliminary closing adjustments of $909,620. The closing adjustments are subject to change. The acquisition established a new strategic Canadian property and diversified the Trust's portfolio of petroleum assets.

The acquisition has been accounted for as a business combination with the fair value of the net assets as follows:

Identifiable assets acquired and liabilities assumed ($CA):		
Oil and gas properties	$	101,294
Decommissioning liabilities		(384)
	$	**100,910**

Although the effective date of the acquisition is January 1, 2015, the estimated amount of revenue (net of royalties) and operating income from this acquisition for the year ended December 31, 2104 is $19.4 million and $13.3 million respectively.

Hardeman properties

On February 27, 2014, the Trust's U.S. operating subsidiary acquired undeveloped acreage and an average 66% working interest in producing properties in Hardeman County, Texas and in Greer, Harmon and Jackson counties, Oklahoma for cash consideration of $5.4 million ($US 4.9 million). The acquisition increased Eagle's previously established position in Hardeman County.

The acquisition has been accounted for as a business combination with the fair value of the net assets as follows:

Identifiable assets acquired and liabilities assumed ($CA):		
Oil and gas properties	$	5,497
Decommissioning liabilities		(88)
	$	**5,409**

The amount of revenue, net of royalties and operating income included in the consolidated statement of comprehensive earnings for the year ended December 31, 2014 from this acquisition was approximately $1.4 million and $0.8 million respectively. It is impracticable to determine the effect of this transaction on net income in the current reporting period.

Property disposition

Permian property

On August 29, 2014, the Trust's U.S. operating subsidiary sold its entire working interest in oil and natural gas properties in the Permian Basin located near Midland, Texas, for net proceeds of $150.1 million ($US 140 million) after closing adjustments. Prior to its disposition the Trust recognized an impairment charge on the asset, reducing its carrying value to its net realizable value. Accordingly, no gain or loss was recorded on the sale.

The disposition has been accounted for as follows:

Identifiable assets and liabilities disposed of ($CA):		
Oil and gas properties	$	151,330
Decommissioning liabilities		(1,189)
	$	**150,141**

At December 31, 2013, Eagle's business combinations consisted of the following:

Acquisitions

Non-Financial forward purchase contract

On April 22, 2013, the Trust announced that it had acquired all of the remaining interest in its oil and natural gas properties in the Permian Basin (the "7.5% Permian Acquisition") located near Midland, Texas for cash consideration of $8.8 million, which includes a closing adjustment credit of $0.1 million. The 7.5% Permian Acquisition had an effective date of January 1, 2013. The Trust now owns a 100% working interest in its Permian area properties.

The 7.5% Permian Acquisition was made pursuant to the terms and conditions of the April 30, 2012 purchase and sale agreement for the Trust's initial acquisition of its interest in the Permian area properties, which closed on May 18, 2012. The terms of the purchase and sale agreement provided the Trust with the right and obligation to purchase the seller's remaining 7.5% undivided interest by April 30, 2013 based on the net present value of such assets as of January 1, 2013, as determined in an independent engineering report.

Consideration was comprised of cash. The acquisition has been accounted for as a business combination with the fair value of the net assets as follows:

Identifiable assets acquired and liabilities assumed ($000's):

Oil and gas properties	$	8,914
Decommissioning liabilities		(84)
	$	**8,830**

Hardeman properties

On November 25, 2013, the Trust acquired producing properties in Hardeman County, Texas (the "Hardeman Acquisition") for cash consideration of $27.1 million, which includes a preliminary closing adjustment credit of $0.6 million. The Hardeman Acquisition had an effective date of October 1, 2013.

Consideration was comprised of cash. The acquisition has been accounted for as a business combination with the fair value of the net assets as follows:

Identifiable assets acquired and liabilities assumed ($000's):

Oil and gas properties	$	27,675
Decommissioning liabilities		(588)
	$	**27,087**

Had this transaction closed on January 1, 2013, the additional revenue, net of royalties, would have been approximately $US 5.8 million for the period ended December 31, 2013. The net income effect is not determinable.

7. Segmented information

Eagle's reportable segments are determined based on the Trust's operations and geographic locations as follows:

- Canadian operations - includes oil and gas exploration, development and the sale of hydrocarbons and related activities in Canada.
- United States operations - includes oil and gas exploration, development and the sale of hydrocarbons and related activities in the continental United States.
- Corporate - Eagle has a corporate head office in Calgary, Alberta and a corporate office in Houston, Texas. Costs incurred in the corporate segment relate to hedging and other expenses incurred in overall financing and management of the Trust.

The Canadian operations segment arose due to the acquisition of the Dixonville property. See note 6 "Business combinations". As the effective date of the acquisition is January 1, 2015, the Trust has not disclosed its operating activities by segment at December 31, 2014. The results from operations for the period December 18, 2014 (the closing date of the acquisition) to December 31, 2014 are immaterial.

Going forward, Eagle's management intends to review financial performance by assessing the funds flow from operations of each operating segment. Funds flow from operations is measured before changes in non-cash operating working capital and provides a measure of each segment's ability to generate cash necessary to fund distributions, capital expenditures and asset retirement obligations.

Total assets of the Trust's reportable segments at December 31, 2014 were as follows:

$000's	Year ended December 31, 2014 Canada	United States	Corporate	Total
Risk management asset	-	-	14,919	14,919
Oil and gas properties, property, plant and equipment	108,539	114,619	-	223,158
Other assets	77	19,018	-	19,095
Total assets	**$ 108,616**	**$ 133,637**	**$ 14,919**	**$ 257,172**

8. Unit-based payments

The following table reconciles unit-based compensation expense (recovery).

$ 000's	Note	**Year Ended December 31, 2014**	Year Ended December 31, 2013
Units issued on performance option surrender	8 (a)	-	270
Restricted unit rights	8 (b)	(515)	762
Unit options	8 (c)	(6,067)	3,016
Unit rights	8 (d)	(1,018)	1,001
Total unit-based compensation expense (recovery)		**$ (7,600)**	$ 5,049

The following table recognizes the unit-based payments liability.

$ 000's	Note	**Year Ended December 31, 2014**	Year Ended December 31, 2013
Units issued on performance option surrender	8 (a)	-	-
Restricted unit rights	8 (b)	61	1,240
Unit options	8 (c)	932	6,998
Unit rights	8 (d)	343	1,392
Total unit-based payments liability		**$ 1,336**	$ 9,630

Grant, surrender and replacement of performance options

On September 14, 2010, performance options were granted as compensation to persons who provided substantial services and expertise in the creation of the Trust and sourcing the acquisition of the Salt Flat Interest. After determining that the performance options would not meet imposed regulatory requirements, the Trust entered into performance option exchange and escrow agreements with holders of the performance options that saw holders surrender their performance options, concurrent with the November 24, 2010 closing of the Trust's initial public offering, in exchange for:

(i) Cash and units equal to the fair market value of the performance options; and

(ii) Cash settled Restricted Unit Rights ("RURs") to capture the foregone distributions and capital appreciation resulting from the fewer number of units that were being issued in exchange for the surrendered performance options.

Note (a)

Units issued upon surrender of performance options

At December 31, 2014, no escrowed units were outstanding. On November 24, 2010, the Trust issued and placed into escrow 387,500 units upon surrender of performance options. The fair value estimate associated with the escrowed units was expensed in the income statement over the escrow period, which is the same period as the performance conditions, with the offsetting entry to unit-based payments liability. Upon release of the units from escrow, the accumulated liability was then transferred to Trust capital.

Note (b)

Cash settled RURs issued upon surrender of performance options

At December 31, 2014, all RURs had vested. Each RUR entitles the holder to receive cash payments equal to the distributions payable on one unit as well as capital appreciation of units. For the year ended December 31, 2014, an aggregate of $664,072 has been paid to the RUR holders (year ended December 31, 2013 - $1,110,734).

The fair value estimate associated with the RURs is expensed or recovered in the income statement with the offsetting entry to unit-based payments liability. At December 31, 2014, the fair value of the RURs was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period with the corresponding change to fair value being recognized in the income statement.

The following schedule shows the continuity of cash settled RURs issued upon surrender of performance options:

	Year Ended December 31, 2014	Year Ended December 31, 2013
Balance, beginning of period	632,500	632,500
Issued	-	-
Forfeited	-	-
Balance, end of period	**632,500**	632,500
Number of RURs vested	**632,500**	632,500

The fair value of the RURs was estimated using the Black-Scholes valuation model with the following inputs:

	Year Ended December 31, 2014	Year Ended December 31, 2013
Fair value at the balance sheet date	**$** 0.10	$ 2.55
Volatility	36%	32%
Life of RURs	6.0 years	7.0 years
Risk-free interest rate	1.83%	2.70%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Effective January 1, 2014, the expected unit price volatility was calculated using the trading history of the Trust's units from November 24, 2010 to December 31, 2014. Prior to January 1, 2014, a representative sample of peer group entities was used in order to determine expected unit price volatility.

Note (c)

Unit option plan

The Trust has an option plan that entitles directors, officers, employees and certain consultants to purchase units of the Trust. The purpose of the option plan is to aid in attracting, retaining and motivating eligible employees and other service providers by enabling such persons to participate in the growth and development of the Trust.

Options are granted at a price equal to the fair market value of the units at the time of grant. The option exercise price is reduced by the amount of distributions paid on the units subsequent to the date of grant, subject to certain conditions specified by the option plan. The options have a 10 year term and vest as to one-third on each of the first, second and third anniversaries of the date of grant. Options granted are not subject to any performance criteria apart from, in respect of directors, officers, employees and certain consultants, their continued service with or employment by the Trust. Options are forfeited if the option holder leaves before the options vest.

The fair value estimate associated with the options is expensed or recovered in the income statement over the vesting period with the offsetting entry to unit-based payments liability. At December 31, 2014, the fair value of the options was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period with the corresponding change to fair value being recognized in the income statement.

The number and weighted average exercise prices of unit options are as follows:

	Year Ended December 31, 2014			Year Ended December 31, 2013		
	Number of options		Weighted average exercise price	Number of Options		Weighted average exercise price
Outstanding, beginning of period	3,126,750	$	7.05	2,214,668	$	8.23
Forfeited	(45,000)		5.51	(249,918)		7.69
Exercised	-		-	-		-
Granted	350,000		5.35	1,162,000		6.72
Outstanding at end of period	**3,431,750**	**$**	**5.94**	3,126,750	$	7.05
Exercisable at end of period	**2,109,095**	**$**	**6.01**	1,411,010	$	7.00

The range of exercise prices of the outstanding options is as follows at December 31, 2014:

		Weighted average exercise price	Weighted average contractual life (years)
$4.87 - $7.52	**$**	**5.94**	**7.6**

The fair value of the options was estimated using the Black-Scholes model with the following inputs:

		Year Ended December 31, 2014		Year Ended December 31, 2013
Fair value - at balance sheet date	**$**	0.37	$	3.76
Unit trading price - closing	**$**	2.33	$	8.07
Exercise price – weighted average	**$**	5.94	$	7.05
Volatility		36%		32%
Option life – weighted average		7.6 years		8.4 years
Distributions – none estimated, due to declining strike price feature		0%		0%
Risk-free interest rate		1.83%		2.70%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. This estimate will be adjusted to the actual forfeiture rate. Effective January 1, 2014, the expected unit price volatility was calculated using the trading history of the Trust's units from November 24, 2010 to December 31, 2014. Prior to January 1, 2014, a representative sample of peer group entities was used in order to determine expected unit price volatility.

Note (d)

Unit Rights (URs) plan

Effective June 14, 2011, the Trust implemented a cash settled Unit Rights ("URs") plan that entitles United States based directors, officers, employees and certain consultants of Eagle Hydrocarbons Inc. (an indirectly held wholly owned subsidiary of the Trust) to participate.

The purpose of the plan is to provide incentive bonus compensation based on the capital appreciation of the units of the Trust and distributions payable in respect of units of the Trust until the URs' termination date, thereby rewarding efforts in the year of grant and providing additional incentive for continued efforts in promoting the growth and success of the Trust and its affiliates, as well as assisting Eagle Hydrocarbons Inc. in attracting and retaining management personnel.

The URs have a 10 year term and vest as to one-third on each of the first, second and third anniversaries of the date of grant. URs granted are not subject to any performance criteria apart from continued service or employment. URs are forfeited if the holder leaves before vesting. Until vested, UR payments will be accrued for the benefit of the holders. Holders of the URs are entitled to receive cash payments on a calendar year basis once the URs vest.

For the year ended December 31, 2014, an aggregate of $29,573 has been paid to the UR holders (year ended December 31, 2013 - $ 78,668).

The fair value estimate associated with the URs is expensed or recovered in the income statement over the vesting period with the offsetting entry to unit-based payments liability. At December 31, 2014, the fair value of the URs was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period with the corresponding change to fair value being recognized in the income statement.

The following schedule shows the continuity of cash settled URs issued:

	Year Ended December 31, 2014	Year Ended December 31, 2013
Balance, beginning of period	997,000	493,000
Issued	-	649,000
Forfeited	(60,000)	(145,000)
Balance, end of period	**937,000**	997,000
Number of unit rights vested	**465,007**	152,670

The Black-Scholes valuation model is used to determine the fair value of the URs issued by the Trust. The fair value of the URs was estimated using the following inputs:

	Year Ended December 31, 2014	Year Ended December 31, 2013
Fair value at the balance sheet date	**$** 0.50	$ 3.62
Volatility	36%	32%
Life of restricted URs	8.1 years	9.2 years
Risk-free interest rate	1.83%	2.70%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Effective January 1, 2014, the expected unit price volatility was calculated using the trading history of the Trust's units from November 24, 2010 to December 31, 2014. Prior to January 1, 2014, a representative sample of peer group entities was used in order to determine expected unit price volatility.

9. Foreign exchange

The Trust has recognized the following in the profit or loss on account of foreign currency fluctuations:

$ 000's	**Year Ended December 31, 2014**	Year Ended December 31, 2013
Net loss arising on settlement of foreign currency transactions arising out of operating activities	**$ 56**	$ 120

The currency in which these transactions and balances are primarily denominated is US dollars and, as such, the Trust is not exposed to significant foreign exchange risk. See note 4 "Financial risk management".

The Trust has recognized the following in unitholders' equity due to the translation of its US subsidiary, which has a US dollar functional currency, to the presentation currency of the Trust, being the Canadian dollar, for financial statement presentation:

$ 000's		**Year Ended December 31, 2014**		Year Ended December 31, 2013
Beginning balance	$	11,100	$	(5,017)
Foreign currency translation gain (loss)		18,394		16,117
Ending balance	**$**	**29,494**	$	11,100

10. Finance expense

$ 000's		**Year Ended December 31, 2014**		Year Ended December 31, 2013
Interest expense on debt	$	2,026	$	2,082
Amortization of deferred financing costs		389		254
Standby and bank fees		162		72
Accretion of decommissioning provision		78		59
Finance expense	**$**	**2,655**	$	2,467

11. Taxation

Reconciliation of effective tax rate

The income tax provision differs from the expected amount calculated by applying the Trust's combined federal and state income tax rate of 35% as follows:

$ 000's		**Year Ended December 31, 2014**		Year Ended December 31, 2013
Earnings (loss) before taxation	$	(47,818)	$	4,914
Expected tax rate		35%		35%
Expected income tax provision		(16,736)		1,720
Decrease (Increase) resulting from:				
Non-deductible items – permanent differences				
Administrative expenses of the Trust		712		266
Unit-based compensation		(2,660)		1,767
Other expenses of the Trust		10		58
Changes in temporary differences for which no amounts are recognized		23,393		2,827
Return to provision true up		55		(848)
Items deductible at the subsidiary level				
Interest on internal debt of subsidiary		(5,877)		(5,530)
Realized foreign exchange gain(1)		2,919		-
Other		(1,606)		(260)
Total income tax expense(2)	**$**	210	$	-

(1) The realized foreign exchange gain is a result of the August 29, 2014, Permian disposition and the subsequent partial repayment of internal debt.

(2) Total income tax expense relates to Texas Franchise Tax.

Deferred tax assets and liabilities:

Deferred tax assets and liabilities are attributable to the following items:

$ 000's		Year Ended December 31, 2014		Year Ended December 31, 2013
Deferred tax liabilities:				
Oil and gas properties in excess of tax value	$	3,422	$	21,440
		3,422		21,440
Less deferred tax assets:				
Non-capital losses – US based		(32,216)		(26,841)
Net deferred tax liability (asset) – before valuation allowance		(28,794)		(5,401)
Unrecognized deferred tax asset		28,794		5,401
Net deferred tax liability (asset)	$	-	$	-

Movement in temporary differences during the year:

$ 000's	Statement of earnings		Balance sheet	
For the year ended December 31,	**2014**	2013	**2014**	2013
Oil and gas properties	$ (18,018)	$ 3,452	$ 3,422	$ 21,440
Non-capital tax losses - U.S. based	(5,375)	(6,279)	(32,216)	(26,841)
	$ (23,393)	$ (2,827)	$ (28,794)	$ (5,401)

The U.S. based tax losses can be used for 20 years and start to expire in 2030. Deferred tax assets have not been recognized in respect of this tax loss due to the entities being newly formed and having a limited history of operations. At this time, it is therefore not probable that future taxable profit will be available against which this benefit can be utilized.

12. Depreciation, depletion and impairment

Depreciation, depletion and impairment are included with the following headings in the income statement:

	Year ended December 31, 2014					
$ 000's		Oil and gas properties		Property, plant and equipment		Total
Depreciation, depletion and amortization	$	35,659	$	187	$	35,846
Impairment		69,531		-		69,531
	$	**105,190**	**$**	**187**	**$**	**105,377**

	Year ended December 31, 2013					
$ 000's		Oil and gas properties		Property, plant and equipment		Total
Depreciation, depletion and amortization	$	31,007	$	190	$	31,197
Impairment		-		-		-
Decommissioning liability loss		9		-		9
	$	31,016	**$**	190	**$**	31,206

Impairment oil and gas properties

For the year ended December 31, 2014, the Trust recognized a $69.5 million (year ended December 31, 2013 - $nil) impairment on its oil and gas properties in relation to the Salt Flat and Permian CGUs. For the three months ended December 31, 2014, the Trust recognized a $49.2 million (three months ended December 31, 2013 - $nil) impairment on its oil and gas properties in the Salt Flat CGU. The impairment was primarily a result of: (i) the decrease in forecast benchmark commodity prices at December 31, 2014 compared to December 31, 2013, (ii) a higher risk adjusted discount rate of 10% used at December 31, 2014 compared to a discount rate of 8% used at December 31, 2013, and (iii) minor technical revisions that resulted in a year over year reduction of the producing component of the probable reserves in Salt Flat. The risk adjusted rate of 10% used to determine the fair value at the measurement date was based on Level 3 value inputs. The remaining impairment charge of $20.3 million related to the sale of the Permian property assets on August 29, 2014 as the disposition proceeds were less than the book value of the Permian CGU.

13. Employees and key management

The aggregate remuneration of employees and executive management was as follows:

$ 000's		**Year ended December 31, 2014**		Year ended December 31, 2013
Salaries and wages	$	7,140	$	5,138
Benefits and other personnel costs		746		503
Unit-based payments (i)		(6,130)		3,791
Total employee and executive remuneration	**$**	**1,756**	$	9,432

(i) Represents the amortization of unit based compensation as recorded in the financial statements. See Note 8 "Unit-based payments".

Key management personnel include the Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, the four Vice-Presidents, the General Counsel/Corporate Secretary and the four external Directors. The aggregate remuneration of key management personnel was as follows:

$ 000's		**Year ended December 31, 2014**		Year ended December 31, 2013
Directors' fees	$	255	$	171
Salaries and wages		3,241		2,469
Benefits and other personnel costs		175		121
Unit-based payments (i)		(6,638)		4,254
Total key management remuneration	**$**	**(2,967)**	$	7,015

(i) Represents the amortization of unit based compensation (recovery) as recorded in the financial statements. See note 8 "Unit-based payments".

No personnel expenses have been capitalized or included in property, plant and equipment or intangible exploration assets.

Key management personnel are entitled to certain amounts and benefits payable in the event of termination of their employment without cause and in the event of a change of control, as outlined in their respective employment agreements.

In the event of termination without just cause, 18 months' salary is payable in the case of the Chief Executive Officer, 12 months' salary in the case of Chief Financial Officer, Chief Operating Officer, Vice President Corporate and Business Development, Vice President, Commercial and Business Development and Vice President Capital Markets and Business Development and 6 months' salary in the case of the Vice President Finance and General Counsel/Corporate Secretary. In addition, in the event of termination without just cause, in the case of the Chief Executive Officer and the Chief Financial Officer, the amount of the last annual bonus received is payable. In the event of termination without just cause of the others officers, a pro-rata portion of the annual discretionary bonus that he or she would have been entitled to receive for the calendar year in which his or her employment was terminated is payable.

In the event of a change of control as defined in the employment agreement, each is entitled to the severance described above if (i) his or her employment is subsequently or contemporaneously terminated without just cause within 12 months of the date of a change of control; (ii) he or she does not continue to be employed as the same level of responsibility or level of compensation and elects within 12 months of the date of the change of control to treat his or her employment as being terminated as a result of such reduction; or (iii) the person elects for any reason to terminate his or her employment within 12 months of the date of the change of control.

14. Earnings (Loss) per unit

$ 000's		Year Ended December 31, 2014		Year Ended December 31, 2013
Earnings (loss) attributable to unitholders (basic)	$	(48,028)	$	4,914
Earnings (loss) attributable to unitholders (diluted)		(52,350)		4,914
Weighted average number of units outstanding (basic)		33,676		30,650
Weighted average number of units outstanding (diluted)		33,811		30,650
Earnings (loss) per unit (basic)	**$**	**(1.43)**	$	0.16
Earnings (loss) per unit (diluted)	**$**	**(1.55)**	$	0.16

Calculation

Basic income per unit for the year ended December 31, 2014 is calculated by dividing the income attributable to unitholders of the Trust by the weighted average number of units outstanding during the period. Diluted income per unit is calculated using the income for the period divided by the weighted average number of units outstanding adjusted for the effects of all potentially dilutive units.

Per unit amounts

Included in the diluted number of units outstanding for the year ended December 31, 2014 is the effect of 135,602 units issuable under the 3,431,750 options outstanding under the unit option plan.

15. Exploration and evaluation assets

$ 000's		December 31, 2014		December 31, 2013
Beginning balance	$	508	$	422
Additions		-		86
Transferred to oil and gas properties		(409)		-
Expense		(154)		-
Foreign exchange adjustment		55		-
Ending balance	**$**	**-**	$	508

At December 31, 2014, the Trust expensed $0.2 million (December 31, 2013 - nil) of exploration and evaluation assets related to a non-operated drilling project that was not commercially viable and for which the Trust did not receive an assignment of economical recoverable reserves.

As most of the activities in the Salt Flat and Hardeman properties are focused on developing the existing proved and probable reserves, exploration and evaluation expenditures are limited.

16. Oil and gas properties

$ 000's		Developed oil and gas assets		Production facilities and equipment		Capitalized future decom-missioning costs		Total
Cost								
At December 31, 2013	$	392,404	$	7,106	$	2,944	$	402,454
Additions		61,781		980		6,766		69,527
Acquisitions		106,319		-		472		106,791
Disposals		(182,734)		-		(1,189)		(183,923)
At December 31, 2014	**$**	**377,770**	**$**	**8,086**	**$**	**8,993**	**$**	**394,849**
Accumulated depreciation and impairment								
At December 31, 2013	$	(73,818)	$	(3,999)	$	(288)	$	(78,105)
Depreciation		(43,316)		(1,722)		(618)		(45,656)
Disposals		23,549		-		1,311		24,860
Impairment		(73,009)		-		-		(73,009)
At December 31, 2014	**$**	**(166,594)**	**$**	**(5,721)**	**$**	**405**	**$**	**(171,910)**
Net book value								
At December 31, 2013	$	318,586	$	3,107	$	2,656	$	324,349
Net change for the period		(107,410)		(742)		6,742		(101,410)
At December 31, 2014	**$**	**211,176**	**$**	**2,365**	**$**	**9,398**	**$**	**222,939**

$ 000's		Developed oil and gas assets		Production facilities and equipment		Capitalized future decom-missioning costs		Total
Cost								
At December 31, 2012	$	304,175	$	6,962	$	1,715	$	312,852
Additions		88,229		581		1,229		90,039
Disposals		-		(437)		-		(437)
At December 31, 2013	$	392,404	$	7,106	$	2,944	$	402,454
Accumulated depreciation and impairment								
At December 31, 2012	$	(41,184)	$	(2,435)	$	-	$	(43,619)
Depreciation		(32,634)		(1,564)		(288)		(34,486)
At December 31, 2013	$	(73,818)	$	(3,999)	$	(288)	$	(78,105)
Net book value								
At December 31, 2012	$	262,991	$	4,527	$	1,715	$	269,233
Net change for the period		55,307		(1,420)		1,229		55,116
At December 31, 2013	$	318,298	$	3,107	$	2,944	$	324,349

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $42,864,322 (December 31, 2013 - $107,887,542) were included in the depletion calculation. 2014 additions to "Developed oil and gas assets" include both the Hardeman property and Dixonville property acquisitions. See note 6 "Business combinations".

Impairment provision

The Trust recognized impairment charges during 2014. See note 12 "Depreciation, depletion, and impairment".

The recoverable amount of the Salt Flat CGU was calculated as $68.1 million based on the greater of its value in use and its fair value less costs to dispose. To determine fair value less costs to dispose, the Trust considered recent transactions within the industry, long-term views of commodity prices, externally evaluated reserve volumes and discount rates specific to the CGU.

The calculation of the recoverable amount is sensitive to the assumptions regarding production volumes, discount rates and commodity prices. A 1% increase (decreased) in the discount rate would have decreased (increased) the fair value estimate by approximately $2.2 million. In addition, a 10% increase (decrease) in the estimated future cash flows would have increased (decreased) the fair value estimate by $5.5 million.

The following commodity price estimates were used in determining whether an impairment to the carrying value of the CGUs existed at December 31, 2014:

	WTI Oil ($US/bbl)	***Edmonton Light Crude ($CAD/bbl)***	***Henry Hub Gas ($US/MMBtu)***	***AECO Spot Gas ($CAD/MMBtu)***
2015	65.00	68.60	3.30	3.50
2016	75.00	83.20	3.80	4.00
2017	80.00	88.90	4.05	4.25
2018	84.90	94.60	4.30	4.50
2019	89.30	99.60	4.55	4.70
2020	93.80	104.70	4.85	5.00
2021	95.70	106.90	5.10	5.30
2022	97.60	109.00	5.30	5.50
2023	99.60	111.20	5.50	5.70
2024	101.60	113.50	5.70	5.90
Escalate thereafter at	2.0%/year	2.0%/year	2.0%/year	2.0%/year

17. Debt

The Trust has entered into a credit facility with a syndicate of Canadian chartered banks. The credit facility is a $US 350 million senior secured revolving facility, which is secured by a first priority security interest on substantially all of the property and assets of Eagle Hydrocarbons Inc. and Eagle Energy Canada Inc. (each a borrower under the credit facility), including all of their respective oil and natural gas properties, and substantially all of the property and assets of Eagle Energy Trust, its other subsidiaries and the administrator of Eagle Energy Trust. Credit facility obligations are also guaranteed by the Trust, its subsidiaries and the administrator of Eagle Energy Trust.

The credit facility is used for general corporate purposes, including working capital, capital expenditures and future acquisitions. Concurrent with the closing of the Dixonville property acquisition on December 18, 2014, the borrowing base was increased from $US 55 million to $US 70 million. On February 11, 2015, the borrowing base was further increased to $US 95 million.

Amounts drawn on the credit facility can be denominated in U.S. or Canadian dollars and may be used for activities in either the U.S. or Canada. The credit facility provides for borrowing by way of LIBOR and base rate loans for amounts drawn in U.S. funds and bankers' acceptances and prime rate loans for amounts drawn in Canadian funds. The margins above base rate, prime rate, LIBOR and bankers' acceptance rate, as applicable, for the credit facility are subject to a pricing grid based on the then applicable ratio of consolidated debt to EBITDAX (the "Margin Ratio"). The credit facility documentation also provides for (i) a standby fee for each lender calculated on the lesser of (a) the unused amount of such lender's commitment and (b) the unused amount of such lender's pro rata share of the borrowing base then in effect, at a percentage based on the applicable Margin Ratio and (ii) an issuance fee on the outstanding amount of any letter of credit equal to the margin applicable to LIBOR loans (subject to a reduction in fees for non-financial letters of credit).

The credit facility has a maturity date of May 27, 2016 and is subject to semi-annual redetermination of the borrowing base by the credit facility lenders no later than May 15 and October 16 of each year. Borrowing base redeterminations are based on, among other things, the proven reserves of Eagle Hydrocarbons Inc. and Eagle Energy Canada Inc.

Under the credit facility, the Trust is required to satisfy certain customary affirmative and negative covenants (including financial covenants). The credit facility documentation provides for customary negative covenants which, among other things, limit the Trust in making distributions to its unitholders if any default, event of default or borrowing base deficiency has occurred and is continuing or would result from such distribution, or if the cash distributions made in any quarter exceed the Available Distributable Cash Flow (as defined in the credit facility agreement) of the Trust for the most recently completed quarter. The credit facility documentation also includes other customary restrictive covenants including limitations on indebtedness, liens, contingent obligations, investments, dispositions, mergers, consolidations, liquidations and dissolutions. In addition, the Trust must maintain, as at the end of each fiscal quarter, a minimum current ratio (the ratio of current assets plus the unused availability under the credit facility to current liabilities excluding any amounts owing under the credit facility) of not less than 1.00 to 1.00, a minimum interest expense coverage ratio of not less than 3.00 to 1.00, and a maximum debt to EBITDAX ratio of 3.00 to 1.00.

Failure to comply with any of these financial covenants, as well as any of the other affirmative and negative covenants, would result in an event of default, which, if not cured or waived, would permit acceleration of the indebtedness pursuant to the credit facility. At December 31, 2014, there were no covenant violations under or in connection with the credit facility.

At December 31, 2014, details of the Trust's credit facility are as follows:

$000's		$US		$CA
Authorized (revolving)	$	70,000	$	81,207
Less:				
Amounts drawn		40,686		47,200
Available	**$**	**29,314**	**$**	**34,007**

The exchange rate in effect at December 31, 2014 was $US 1 equal to $CA 1.16. The amount drawn on the credit facility at December 31, 2014 is denominated in Canadian funds. Subsequent to year end, the Trust's credit facility was expanded to $US 95 million. See note 23 "Subsequent events".

At December 31, 2013, details of the Trust's credit facility are as follows:

$000's		$US		$CA
Non-revolving	$	10,000	$	10,636
Revolving		80,000		85,088
Total authorized		90,000		95,724
Less: Current debt		10,000		10,636
Long-term debt		63,450		67,485
Available	$	16,550	$	17,603

The exchange rate in effect at December 31, 2013 was $US 1 equal to $CA 1.06.

18. Decommissioning liability

$000's		**December 31, 2014**		December 31, 2013
Beginning balance	$	3,036	$	1,744
Acquisition		472		672
Additions		344		191
Changes in estimates		7,981		315
Disposition		(1,189)		-
Abandonment expenditures		(212)		(9)
Accretion (unwinding of discount)		78		61
Effects of exchange rate		(163)		62
Ending balance	**$**	**10,347**	$	3,036

The decommissioning provision reflects the present value of internal estimates of future decommissioning costs of the Trust's net ownership position in oil and gas wells and related facilities at the relevant balance sheet date determined using local pricing conditions and requirements. The liability would be incurred over the life of the assets, with the majority after the year 2050. The timing of payments related to provisions is uncertain and is dependent on various items which are not always within Management's control.

The provision was estimated using existing technology, at current prices (adjusted for a 2% inflation rate), and discounted using a risk-free discount rate of 2% (December 31, 2013 – 3%) for the Salt Flat properties, and 2.7% for the Hardeman and Dixonville properties (December 31, 2013 - 3% for Hardeman and Permian properties). A 1% decrease in the risk-free discount rate would have increased the liability by $3,186,736 as at December 31, 2014 (December 31, 2013 - $617,305).

Included in the balance at December 31, 2014 is $88,253 of decommissioning liability recorded as part of the Hardeman property acquisition, a $1,189,278 reduction in decommissioning liability recorded as part of the Permian disposition, and $384,278 of decommissioning liability recorded as part of the Dixonville property acquisition. See note 6 “Business combinations”.

19. Trust capital

Authorized

The beneficial interests in the Trust are represented and constituted by one class of units. An unlimited number of common voting Trust units may be issued pursuant to the Trust Indenture. Each unit represents an equal, undivided beneficial interest in the net assets of the Trust, and all units rank equally and ratably with all other units. Each unit entitles the holder to one vote at all meetings of unitholders. Unitholders are entitled to receive non-cumulative distributions from the Trust if, as, and when declared by the Trust.

Trust units are redeemable at any time on demand by the holders thereof. Upon receipt of a redemption request by the Trust, the holder is entitled to receive a price per Trust unit (the “Market Redemption Price”) equal to the lesser of: (i) 90% of the volume weighted average trading price of a unit during the last 10 trading days; and (ii) 100% of the volume weighted average trading price of a unit on the redemption date. The aggregate Market Redemption Price payable by the Trust in respect of any units tendered for redemption during any calendar month shall be satisfied by way of a cash payment on or before the fifth business day after the end of the calendar month following the calendar month in which the units were tendered for redemption. Unitholders are not entitled to receive cash upon the redemption of their units if the total amount payable by the Trust in respect of such units and all other units tendered for redemption in the same month exceeds $100,000. If a unitholder is not entitled to receive cash, the redemption may be satisfied by distributing notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust units tendered for redemption. It is anticipated that the redemption right will not be the primary mechanism for unitholders to dispose of their units.

At December 31, 2014, the Trust units outstanding were as follows:

	December 31, 2014			December 31, 2013		
$000’s	**Number of units**		**Amount**	Number of units		Amount
Beginning balance	32,149	$	297,447	29,269	$	276,526
Issuance of Trust capital pursuant to DRIP	2,868		17,421	2,775		20,173
Fair value adjustment	-		2,319	-		-
Units released from escrow	-		-	105		859
Trust Unit issuance costs	-		(37)			(111)
Ending balance	**35,017**	**$**	**317,150**	32,149	$	297,447

For the year ended December 31, 2014, the Trust incurred $37,099 (December 31, 2013 - $111,434) of unit issuance costs in conjunction with the DRIP. The Trust issued 2,868,203 units at a weighted average price of $6.07 per unit for total gross proceeds of $17,421,160 under the DRIP (as described below).

DRIP Plan (Premium Distribution and Distribution Reinvestment Plan)

The Distribution Reinvestment Plan (the “Plan”) provided eligible unitholders with the opportunity to reinvest their monthly cash distributions in new trust units at a discount to the average market price (as defined in the Plan) on the applicable distribution payment date. Commencing with the distribution paid on October 23, 2014, the Trust suspended the Premium Distribution™ component of the Plan and amended the Plan to reduce the market discount that Trust units can be acquired for under the regular distribution reinvestment component from 5% to 2%. Commencing with the distribution paid on February 23, 2015, the Trust also suspended the regular distribution reinvestment component of the Plan. See note 23 “Subsequent events”.

20. Accumulated cash distributions

$ 000's		December 31, 2014		December 31, 2013
Beginning balance	$	(80,454)	$	(48,020)
Accumulated cash distributions		(33,524)		(32,434)
Fair market value of units issued under the DRIP		(2,337)		-
Total accumulated cash distributions	**$**	**(116,315)**	$	(80,454)

In accordance with IFRS 13, at December 31, 2014, the Trust recorded a non-cash fair value adjustment of $2.3 million (December 31, 2013 - $nil) for units issued under the DRIP.

21. Related party disclosures

The Trust has no party holding voting control.

Key management

Key management personnel include the Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, the four Vice-Presidents, General Counsel/Corporate Secretary and the four external Directors. Refer to note 14 "Employees and key management".

Intercompany transactions

There are certain intercompany transactions among the subsidiaries comprising these consolidated financial statements of the Trust. These transactions have been eliminated in consolidation.

22. Commitments

Operating lease commitment – head office lease in Calgary, Alberta

On January 1, 2013, the Trust entered into a lease for office space in Calgary which has an approximate 61 month term from January 8, 2013 to February 7, 2018. Future minimum lease payments during the term of the lease approximate $2.4 million and include a leasehold improvements allowance up to $0.3 million, with 37 months and approximately $1.5 million remaining at December 31, 2014.

Operating lease commitment – office lease in Houston, Texas

The Trust entered into a lease in Houston on April 1, 2011, which originally had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease was extended for an additional 63 month period from October 1, 2013 to December 31, 2017 and the premise space was expanded to incorporate additional square footage. Future minimum lease payments during the term of the lease include a leasehold improvement allowance of $US 0.1 million and approximate $US 0.9 million, with 36 months and approximately $US 0.9 million remaining at December 31, 2014. In $CA the remaining future minimum lease payments approximate $1.0 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.16.

Legal proceedings

The Trust is involved in various litigation and claims in the normal course of the Trust's operations. Although the outcome of these claims cannot be predicted with certainty, the Trust does not expect these matters to have a material adverse effect on Eagle's financial position, cash flows or results of operations. If an unfavorable outcome were to occur, there exists the possibility of a material adverse impact on the Trust's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Trust determines that the loss is probable and the amount can be reasonably estimated. The Trust believes it has made adequate provision for such legal claims.

23. Subsequent events

Normal course issuer bid

On January 19, 2015, the Trust announced that it had received acceptance from the Toronto Stock Exchange (the "TSX") of Eagle's notice of intention to make a Normal Course Issuer Bid ("NCIB"). Under the NCIB, during the one-year period commencing January 21, 2015 and ending January 20, 2016, Eagle can purchase for cancellation up to 2,852,829 of its units ("Units"), representing ten percent of its public float as of January 16, 2015. The NCIB will be administered through the facilities of the TSX, or alternative trading systems, if eligible, and will conform to their regulations.

The actual number of Units purchased under the NCIB, the timing of such purchases and the price at which the Units are bought will depend upon future market conditions, and upon potential alternative uses for Eagle's cash resources. Any purchases will be made by Eagle at the prevailing market price of the Units at the time of purchase and will be subject to a maximum daily purchase volume of 30,732 Units (being 25% of the average daily trading volume of the Units from July 1, 2014 to December 31, 2014 of 122,928 units) except as otherwise permitted under the TSX NCIB rules. All Units purchased under the NCIB will be cancelled.

Eagle also announced that it had entered into an automatic unit purchase plan (the "Plan") with a broker in order to facilitate repurchases of its Units under its NCIB. Under Eagle's Plan, Eagle's broker may repurchase Units under the NCIB at any time including without limitation when Eagle would ordinarily not be permitted to due to regulatory restrictions or self-imposed trading blackout periods. Purchases will be made by Eagle's broker based on the parameters prescribed by the TSX and the terms of the Plan. The Plan will be in place for the one-year period of the NCIB. The Plan has been reviewed by the TSX.

Suspension of DRIP

On January 19, 2015, Eagle announced that commencing with the distribution paid on February 23, 2015 for unitholders of record on January 30, 2015, Eagle's Distribution Reinvestment Plan ("DRIP") was suspended until further notice. Unitholders who had elected to participate in the DRIP will receive cash distributions on the payment date. Unitholders that were enrolled in the DRIP when the plan is suspended will remain enrolled at reinstatement and will automatically resume participation in the DRIP if, and when, the DRIP is reinstated.

Expanded credit facility

Effective February 11, 2015, Eagle's credit facility has expanded to $US 95 million. Amounts drawn on the credit facility can be denominated in US or Canadian dollars and be used for activities in either the United States or Canada. As part of this credit facility expansion, Eagle added a third bank, National Bank Financial, to the existing syndicate, which continues to be led by Scotiabank, with CIBC as the other participant. The credit facility provides for semi-annual evaluation no later than May 15 and October 15 of each year.

Corporate Information

Board of Directors

David M. Fitzpatrick
Chairman of the Board

Bruce K. Gibson (1)
Director

Warren D. Steckley (2)
Director

Joseph W. Blandford (3)
Director

Richard W. Clark
President, Chief Executive Officer and Director

(1) Audit Committee Chair
(2) Reserves & Governance Committee Chair
(3) Compensation Committee Chair

Officers

Richard W. Clark
President, Chief Executive Officer and Director

Kelly A. Tomyn
Chief Financial Officer

J. Wayne Wisniewski
Chief Operating Officer

M. Scott Lovett
Vice President, Corporate and Business Development

Eric C. McFadden
Vice President, Capital Markets and Business Development

Jo-Anne M. Bund
General Counsel and Corporate Secretary

Auditors

PricewaterhouseCoopers LLC

Trustee and Transfer Agent

Computershare Trust Company of Canada

Engineering Consultants

Netherland Sewell and Associates, Inc.
McDaniel and Associates Consultants Ltd.

Bankers

Bank of Nova Scotia
Canadian Imperial Bank of Commerce
National Bank of Canada

Legal Counsel

Bennett Jones LLP

TSX: EGL.UN

EAGLE ENERGY™ TRUST

Calgary Office

Eagle Energy Inc.
Suite 2710, 500 – 4th Avenue SW
Calgary, Alberta T2P 2V6

Phone: (403) 531-1575
Fax: (403) 508-9840
Email: info@eagleenergytrust.com

Houston Office

Eagle Hydrocarbons Inc.
Suite 3005, 333 Clay Street
Houston, Texas 77002

Phone: (713) 300-3245
Fax: (713) 300-3240
Email: info@eagleenergytrust.com

www.EagleEnergyTrust.com