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First Quarter 2015 Financial Report

EAGLE ENERGY™
TRUST

Management's Discussion and Analysis

May 7, 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 May 7, 2015, should be read in conjunction with the Trust's unaudited interim condensed consolidated financial statements and accompanying notes for the three months ended March 31, 2015 ("**Interim Financial Statements**") and the Trust's audited consolidated financial statements and accompanying notes and related MD&A for the year ended December 31, 2014 and the Trust's Annual Information Form dated March 19, 2015 ("**AIF**"), which are available online at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

The Condensed Consolidated Interim 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 condensed consolidated interim 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 March 31, 2015 was $US 1 equal to $CA 1.27 (December 31, 2014 - $US 1 equal to $CA 1.16), and the average foreign exchange rate for the three months ended March 31, 2015 was $US 1 equal to $CA 1.24 (for the three months ended March 31, 2014 - $US 1 equal to $CA 1.10).

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 and refers to non-IFRS financial measures. Investors should read the "Note about forward-looking statements" and "Non-IFRS financial measures" sections at the end of this MD&A.

Other financial data has been prepared in accordance with IFRS.

Overview 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 in the United States and Canada 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.

This MD&A discusses the Trust's operating segments in the United States and Canada, in addition to its Corporate segment. The United States segment relates to the Trust's assets in Texas and Oklahoma and the Canadian segment relates to the Trust's assets in Alberta. The Corporate segment includes expenditures related to the Trust's hedging program, public company, and other expenses incurred in the overall financing and administration of the Trust.

Highlights for the three months ended March 31, 2015

- First quarter average working interest sales volumes of 2,995 barrels of oil equivalent per day ("boe/d") (97% oil, 2% natural gas liquids, 1% natural gas) with production on track to meet 2015 full year guidance of 2,950 to 3,150 boe/d.
- First quarter funds flow from operations of $7.8 million ($28.67 per boe).
- A strong hedging position that held quarter over quarter cash flow to a decrease of 25%, despite a 48% drop in realized field prices over the same period.
- First quarter unitholder distributions maintained at $0.09 per unit ($0.03 per unit per month), with a 2015 projected corporate payout ratio of 94%.
- Eagle has renewed its credit facility at $US 85 million, previously $US 95 million, realizing annual savings of more than $80,000 through reduced commitment and extension fees. Eagle was only 35% drawn on the facility at quarter end, leaving approximately $60 million of undrawn availability on the facility. During the semi-annual borrowing base review, the maturity date of the credit facility was extended to May 26, 2017. Pricing remained the same and there were no material changes made to the credit facility conditions or covenants.

2015 Outlook

This outlook section is intended to provide unitholders with information about Eagle's expectations 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.

Eagle's 2015 guidance for its capital budget, production and operating costs is unchanged. Forecast funds flow from operations and debt to trailing cash flow have been updated to include first quarter actual results and April to December forecast results. Eagle's guidance is summarized 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	$28.1 mm	4
Debt to Trailing Cash Flow	1.3x	

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.

a. Based on a forecast $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 94%.

b. Eagle's 2015 capital budget of $13.7 million consists of the following:

- Salt Flat, Texas
  - 3 (3.0 net) horizontal oil wells
  - Seismic processing, horizontal pump installations
- 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

(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) 2015 forecast funds flow from operations is approximately $28.1 million based on the following assumptions:

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

b. Forecast 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".

2015 Sensitivities

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

Sensitivity to Commodity Price

	2015 Average WTI (Production 3,050 boe/d)		
	$US 50 (FX 1.30)(5)	$US 60 (FX 1.25)(5)	$US 70 (FX 1.20)(5)
Cash Flow	$25.6	$28.1	$30.3
Corporate Payout Ratio	105%	94%	86%
Debt to Trailing Cash Flow	1.5x	1.3x	1.1x

Sensitivity to Production

	2015 Average Production (boe/d) (WTI $US 60, F/X 1.25)		
	2,950	3,050	3,150
Cash Flow	$27.3	$28.1	$29.0
Corporate Payout Ratio	97%	94%	91%
Debt to Trailing Cash Flow	1.3x	1.3x	1.2x

Assumptions:

(1) Annual distribution is $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
Gas price[(2)]	+ USD $0.10/mcf Henry HUB	9	0.00
Oil price [(2)]	+ USD $1.00/bbl WTI	236	0.01
Gas production	+1000 mcf/d	134	0.00
Oil production	+100 bbls/d	167	0.00
Currency [(2)]	+CDN weaken by $0.01	61	0.00
Interest rate	+1% prime	(119)	0.00

Notes:

(1) Per unit figures are based on 35,031,926 weighted average basic units outstanding for the three months ended March 31, 2015.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate equal to year to date average working interest sales volumes of 2,995 boe/d.

Consolidated results of operations

Production

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	%
Oil (bbl/d)	2,895	2,545	14
Natural gas (Mcf/d)	273	1,316	(79)
Natural gas liquids (bbl/d)	55	246	(78)
Oil equivalent sales volumes (boe/d @ 6:1)	2,995	3,010	(1)

Working interest sales volumes for the first quarter of 2015 averaged 2,995 boe/d (97% oil, 2% natural gas liquids, 1% natural gas). The January 1, 2015 Dixonville asset acquisition has effectively replaced the Permian Basin production, which was sold effective August 29, 2014. In addition, the Permian divestiture and subsequent Dixonville acquisition increased the percentage of oil production from 85% to 97%.

Revenue

($000's)		Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	%
Oil	$	13,034	$	24,527	(47)
Natural gas		71		587	(88)
Natural gas liquids		85		955	(91)
Other		203		-	100
Sales before royalties	$	13,393	$	26,069	(49)

Realized prices					
Oil ($/bbl)	$	50.03	$	107.07	(53)
Natural gas ($/Mcf)		2.89		4.96	(42)
Natural gas liquids ($/bbl)		17.30		43.24	(60)
Other ($/bbl)		0.75		-	100
Sales before royalties ($/boe)		49.69		96.23	(48)
Royalties ($/boe)		(13.62)		(26.19)	(48)
Revenue ($/boe)	$	36.07	$	70.04	(48)

Benchmark prices					
Oil – WTI ($US/bbl)	$	48.63	$	98.68	(51)
Natural gas – Henry HUB ($US/Mcf)	$	2.81	$	4.73	(41)

The Trust's quarterly revenue is 97% derived from oil. Realized oil prices in Canadian dollars were essentially level with benchmark $US WTI for the quarter. 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 March 31, 2015, the benchmark WTI price decreased 51% from the prior year's comparative quarter. This is comparable to the decrease in the realized oil price, as the negative effect of the increase in the differential between the Trust's realized oil price and the WTI benchmark was offset by the positive effect of a much weaker Canadian dollar.

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 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 $7.3 million ($27.07/boe) for the three months ended March 31, 2015. See *Realized and unrealized risk management gain/loss.*

The overall royalty rate of approximately 27% was consistent with prior periods.

Operating costs

		Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	%
Transportation and marketing expenses		40		196	(80)
Operating costs		5,938		4,072	46
	$	5,978		4,268	40
Per boe:					
Transportation and marketing expenses		0.15		0.72	(79)
Operating costs		22.03		15.03	47
	$	**22.18**	$	15.75	41

The Trust intends to continue to improve efficiencies and maintains its 2015 operating expense guidance of $1.8 million to $2.0 million per month. Refer to the "Segmented operations" section of this MD&A.

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 of 2014, 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 restated its revenue and transportation and marketing expense for the prior year comparative period to reflect this adjustment.

For the three months ended March 31, 2014, the impact of the oil transportation restatement to both revenue and transportation and marketing expenses was a $0.5 million reduction.

Depreciation, depletion and amortization

	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014		%
	$	**/boe**	$	/boe	
Depreciation, depletion and amortization		**22.76**		32.07	(29)

The depletion, depreciation, and amortization provision for the three months ended March 31, 2015 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 report prepared by the Trust's independent reserves evaluators.

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 and lower future development costs associated with the reserves. As commodity prices recover, the percentage of free cash flow realized by the Trust will increase.

Field netback

	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	
($000's)	**$**	**$ /boe**	$	$ /boe
Sales before royalties	13,393	49.69	26,069	96.23
Royalties	(3,671)	(13.62)	(7,096)	(26.19)
Operating expenses	(5,938)	(22.03)	(4,072)	(15.03)
Transportation and marketing expenses	(40)	(0.15)	(196)	(0.72)
Field netback	**$** 3,744	**$** 13.89	$ 14,705	$ 54.29
Sales volumes (boe/d)		**2,995**		3,010

During the quarter, benchmark WTI averaged $US 48.63 per barrel and the Trust realized a field netback of $13.89 per boe. On a year over year comparison, field netbacks decreased 75% on a per barrel basis due to the sharp drop in commodity prices. Monthly operating costs are tracking to 2015 guidance of $1.8 million to $2.0 million per month. Refer to the "Segmented operations" 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
NYMEX (1)	500 bbls/d	Jul 2015 to Sep 2015	$55.45
NYMEX (1)	200 bbls/d	Jul 2015 to Sep 2015	$55.60
NYMEX (1)	400 bbls/d	Oct 2015 to Dec 2015	$57.10

(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 March 31, 2015	Three Months Ended March 31, 2014	%
Realized gain (loss)	7,295	(818)	992
Unrealized gain (loss)	(4,183)	(1,114)	(275)
Net gain (loss) - Commodity	**$ 3,112**	$ (1,932)	261
Realized gain (loss)	-	(24)	-
Unrealized gain (loss)	-	(194)	-
Net gain (loss) - Foreign exchange	-	(218)	-
Total net gain (loss)	**$ 3,112**	$ (2,150)	245

On a quarter over quarter 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 the contracts that are in place, 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, hence the change in value of the unrealized portion of the commodity contracts. Continued weakness in the forward commodity pricing environment since the previous quarter has strengthened the future values of the unrealized contracts on the balance sheet at March 31, 2015.

Eagle had approximately 1,600 barrels of oil per day hedged at an average WTI price of $US 90.72 per barrel during the first quarter of 2015. For the second quarter of 2015, 1,600 barrels of oil per day are hedged at an average WTI price of $US 90.72; for the third quarter of 2015, 1,300 barrels of oil per day are hedged at an average WTI price of $US 69.95; and for the fourth quarter of 2015, 990 barrels of oil per day are hedged at an average WTI price of $US 74.98.

Finance expense

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	%
Finance expense	772	877	(12)
Per boe	**$ 2.87**	$ 3.24	(11)

For the three months ended March 31, 2015, finance expense decreased over the prior year's comparative quarter due to the decrease of the Trust's outstanding advances on its credit facility.

As of March 31, 2015, the effective interest rate on bank debt for the period was 4.2% compared to 3.7% for the comparable period in 2014. During the quarter, the Trust borrowed by way of banker's acceptance (funds drawn were denominated in Canadian dollars), which was lower than the prime rate option on its borrowings. The prior year's comparative quarter utilized borrowings by way of LIBOR loans (funds drawn were denominated in US dollars), which was lower than the base rate option on its borrowings.

Administrative expenses

		Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	%
Administrative expenses		2,460		2,555	(4)
Per boe	**$**	**9.13**	$	9.43	(3)

Total administrative expenses for the first quarter were $2.5 million, representing approximately 22% of full year 2015 expected levels. Staff and related employment costs accounted for 75% of administrative expenses. In light of the weakened commodity price environment, Eagle undertook a comprehensive review of administrative expenses which resulted in a reduction or termination of various consulting contracts and a 15% reduction in the number of full time employees.

Unit based compensation

		Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	%
Unit-based compensation recovery	**$**	**(123)**	$	(1,874)	93

A non-cash unit based compensation recovery of $0.1 million was recorded during the first quarter of 2015 ($1.9 million recovery for the three months ended March 31, 2014). This was due to the change in fair market valuation as a result of an increase in the expected unit price volatility calculation based on the trading history of the Trust's units when compared to the prior year's comparative quarter.

The dollar amount of unit-based compensation recovery does not represent cash paid by the Trust.

The actual total value received by holders of the unit-based compensation awards will depend on the accumulated distributions actually paid by the Trust combined with (1) the actual year over year price appreciation of the trust units (for holders of restricted unit rights and unit rights), or (2) 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: (1) the restricted unit rights, (2) the options and (3) the unit rights. Any changes in fair value are recorded as an expense or recovery.

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 ended March 31, 2015, the recovery was due to the lower year to date price of the Trust's units. The average exercise price of the unit options of $5.70 is still significantly below the March 31, 2015 closing unit price of $2.41.

During the first quarter, $56,925 million (three months ended March 31, 2014 - $166,037 million) was paid out in cash for amounts related to vested restricted unit rights. The decrease in payments related to vested restricted unit rights is due to the reduction in the cash distribution amounts paid. Effective with the January 23, 2015 payment (for distributions declared in December 2014), the distribution amount paid per unit was reduced from $0.0875 to $0.03 per unit per month. The liability that was, and continues to be, accrued from inception for these cash settled awards was reduced by such cash payments.

Summary of quarterly results

	Q1/2015	Q4/2014	Q3/2014	Q2/2014	Q1/2014	Q4/2013	Q3/2013	Q2/2013
($000's except for boe/d and per unit amounts)								
Sales volumes – boe/d	2,995	1,929	2,859	3,341	3,010	2,994	3,052	3,022
Revenue, net of royalties	9,722	10,238	17,143	20,821	18,973	17,119	19,046	16,698
per boe	36.07	57.67	65.19	68.48	70.04	62.15	67.84	60.73
Field netback	3,744	6,841	12,832	16,144	14,705	13,106	15,945	14,352
per boe	13.89	38.54	48.80	53.10	54.29	47.58	56.79	52.20
Funds flow from operations	7,727	5,670	7,476	10,471	10,341	8,794	11,615	11,977
per boe	28.67	31.94	28.43	34.44	38.18	31.93	41.37	43.56
per unit – basic	0.22	0.16	0.22	0.32	0.32	0.28	0.37	0.39
per unit – diluted	0.22	0.15	0.16	0.28	0.25	0.28	0.37	0.39
Earnings (loss)	5,477	(35,192)	8,104	(23,158)	2,218	156	(3,241)	3,919
per unit – basic	0.16	(1.01)	0.24	(0.70)	0.07	0.00	(0.10)	0.13
per unit - diluted	0.16	(1.13)	0.18	(0.70)	0.02	0.00	(0.10)	0.13
Cash distributions declared	3,153	7,159	9,036	8,775	8,555	8,376	8,204	8,026
per issued unit	0.0900	0.2050	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625
Current assets	31,459	33,245	76,566	8,802	9,116	9,889	9,950	11,443
Current liabilities	8,642	10,720	13,587	32,878	33,348	30,461	20,942	19,874
Total assets	265,342	257,172	240,458	320,182	356,332	335,679	306,021	311,271
Total non-current liabilities	60,835	57,547	2,565	80,126	79,684	70,521	55,069	50,654
Unitholders' equity	195,865	188,905	224,306	207,178	243,300	234,697	230,010	240,743
Units outstanding for accounting purposes	35,023	35,017	34,821	33,739	32,836	32,149	31,469	30,707(1)
Units issued	35,023	35,017	34,821	33,739	32,836	32,149	31,469	30,813

Note:

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

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

For the three months ended March 31, 2015, sales volumes increased 55% compared to the previous quarter because first quarter sales volumes reflect the full quarter of the newly acquired the Dixonville properties. With the exception of the third and fourth quarters of 2014 (which had reduced sales volumes due to the Permian property disposition) and the fourth quarter of 2013, (which encountered non-recurring weather related delays and non-owned infrastructure problems), production has generally increased commensurate with well tie-ins and acquisitions.

Funds flow from operations increased in the first quarter of 2015 when compared to the prior quarter due to (i) higher sales volumes resulting from the Dixonville acquisition, (ii) lower general and administrative expenses, and (iii) stronger realized hedging gains. These were partially offset by (i) significantly lower realized commodity prices, and (ii) higher operating costs. Generally, in times of steady or increasing prices, funds flow from operations grows faster as sales volumes increase (and vice versa). This is because certain expenses tend to be more fixed in nature, such as general and administrative expenses, and do not decrease as sales volumes decrease.

Earnings (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 items of a non-cash nature that factor into the calculation of earnings (loss), and those that are required to be fair valued at each quarter end. By way of example, first quarter 2015 funds flow from operations increased 36% from the fourth quarter 2014 while the absolute swing from a loss in the fourth quarter to first quarter earnings was by a much larger percentage. This occurred primarily due to a non cash foreign exchange gain recognized on the loan to the Trust's US subsidiary. Additionally, higher sales volumes were recognized in the first quarter of 2015 but tempered by lower commodity prices. The weakened forward commodity price environment has increased the fair market valuation of Eagle's forward commodity contracts in the first quarter.

Eagle had approximately 1,600 barrels of oil per day hedged at an average WTI price of $US 90.72 per barrel during the first quarter of 2015. For the second quarter of 2015, 1,600 barrels of oil per day are hedged at an average WTI price of $US 90.72; for the third quarter of 2015, 1,300 barrels of oil per day are hedged at an average WTI price of $US 69.95; and for the fourth quarter of 2015, 990 barrels of oil per day are hedged at an average WTI price of $US 74.98.

Segmented operations

The Trust's operating activities relate solely to the exploration, development and production of petroleum and natural gas resources in the United States and Canada. Costs incurred in the Corporate segment relate to The Trust's hedging program and other expenses incurred in overall financing and administration of the Trust.

United States

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	%
Production			-
Oil (bbls/d)	1,765	2,545	(31)
Natural gas (mcf/d)	231	1,316	(82)
Natural gas liquids (bbls/d)	55	246	(78)
Oil equivalent sales volumes (boe/d @ 6:1)	**1,859**	3,010	(38)
Activity			
Capital expenditures ($000's)	**$ 2,210**	$ 16,838	(87)
Wells drilled (rig-released)			
Gross	-	2.0	-
Net	-	1.6	-
Wells brought on-stream			
Gross	-	2.0	-
Net	-	1.6	-

($000's)	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	%
Sales before royalties	$ 9,602	$ 26,069	(63)
Royalties	(2,802)	(7,096)	(61)
Operating expenses	(3,856)	(4,072)	(5)
Transportation and marketing expenses	(31)	(196)	(84)
Field netback	**$ 2,913**	$ 14,705	(80)
($/boe)			
Sales before royalties	$ 57.39	96.23	(40)
Royalties	(16.75)	(26.19)	(36)
Operating expenses	(23.05)	(15.03)	53
Transportation and marketing expenses	(0.19)	(0.72)	(74)
Field netback	**$ 17.40**	$ 54.29	(68)

The Trust spent a total of $2.2 million on capital activity in the United States during the first quarter of 2015 with average working interest sales volumes of 1,859 boe/d. To date, results from the capital program have met expectations and the Trust is on track to meet its 2015 guidance.

Salt Flat Properties, Texas

For the three months ended March 31, 2015, $1.2 million was spent drilling the first well of a three well program (rig released in April) and purchasing production equipment.

Hardeman Properties, Texas and Oklahoma

For the three months ended March 31, 2015, $1.0 million was spent drilling the first well of a three well program and a salt water disposal well (both rig released in April). Eagle has implemented a number of enhancements that have resulted in production gains, and 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.

Canada

		Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	%
Production					
Oil (bbls/d)		1,129		-	-
Natural gas (mcf/d)		42		-	-
Natural gas liquids (bbls/d)		-		-	-
Oil equivalent sales volumes (boe/d @ 6:1)		**1,136**		-	-
Activity					
Capital expenditures ($000's)	**$**	**850**	$	-	-

($000's)		Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	%
Sales before royalties	$	3,791	$	-	-
Royalties		(869)		-	-
Operating expenses		(2,082)		-	-
Transportation and marketing expenses		(9)		-	-
Field netback	**$**	**831**	$		-
($/boe)					
Sales before royalties	**$**	37.08	$	-	-
Royalties		(8.50)		-	-
Operating expenses		(20.36)		-	-
Transportation and marketing expenses		(0.08)		-	-
Field netback	**$**	**8.14**	$		-

Dixonville Properties, Alberta

Effective January 1, 2015, a subsidiary of the Trust acquired a 50% non-operated working interest in the Dixonville Montney "C" oil pool, located in the Peace River region of Alberta, Canada. Eagle's 2015 budget in Canada will be limited to maintenance capital at Dixonville.

For the three months ended March 31, 2015, $0.9 million was spent on pipeline facilities. Production volumes for the three months ended March 31, 2015 were 1,136 boe/d. In the quarter, the majority of the remaining pipeline and infrastructure work was delayed until February due to warmer than expected January weather causing access issues into some parts of the field. Due to these delays, a full production restart in these areas did not commence until March. Run times in the field continued to improve throughout March. It is expected that production will continue to ramp up through the second quarter with continued increased run-times on the wells.

Corporate

($000's)		Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	%
Administrative expenses	$	(508)	$	(371)	37
Risk management gain (loss) - realized		7,295		(842)	966
Cash settled award payments		(57)		(166)	(66)
Realized foreign exchange gain (loss)		(224)		(43)	420
Finance expense		(571)		(758)	(25)
Funds flow from operations	**$**	**5,935**	$	(2,180)	372

At the Corporate level, on a quarter over quarter basis, the net value of 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.

As a result of the Trust reducing the distribution from $0.0875 to $0.03 per unit per month, cash settled award payments decreased 66% when compared to the same quarter of the previous year.

The average foreign exchange rate for the three months ended March 31, 2015 was $US 1 equal to $CA 1.24 (for the three months ended March 31, 2014 - $US 1 equal to $CA 1.10). The increase in realized foreign exchange loss is due to the weakened Canadian dollar.

Finance expense is incurred on borrowings under the Trust's revolving credit facility. The decrease in quarter over quarter finance expense is due to decreased borrowings under the Trust's credit facility.

Liquidity and capital resources

Generally, three sources of funding are available to the Trust: (1) internally generated funds flow from operations; (2) debt financing, when appropriate; and (3) the issuance of additional units, if available on favourable terms.

The external debt to cash flow ratio is currently well below 2.0 times. This ratio may increase at certain times as a result of acquisitions or phasing of the capital program. As at March 31, 2015, the Trust's ratio of ending debt to trailing cash flow on an annualized basis was approximately 1.2 to 1.0. Year end 2015 ending debt to trailing cash flow based on 2015 guidance is 1.3 times. Refer to the "2015 Outlook" section of this MD&A.

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 "2015 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 March 31, 2015		Three Months Ended March 31, 2014	
($000's)	**$**	**$ /boe**	$	$ /boe
Field netback	3,744	13.89	14,705	54.29
Cash settled award payments	(57)	(0.21)	(166)	(0.61)
Administrative expenses	(2,460)	(9.13)	(2,555)	(9.43)
Realized risk management gain (loss)	7,295	27.07	(842)	(3.11)
Finance expense	(571)	(2.12)	(758)	(2.80)
Realized foreign exchange gain (loss) (1)	(224)	(0.83)	(43)	(0.16)
Funds flow from operations	**$ 7,727**	**$ 28.67**	$ 10,341	$ 38.18

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 a result of the Dixonville acquisition and the expansion of the banking syndicate, Eagle's credit facility was further expanded to $US 95 million on February 11, 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.

In May 2015, Eagle renewed its credit facility at $US 85 million, previously $US 95 million, realizing annual savings of more than $80,000 through reduced commitment and extension fees. Eagle was only 35% drawn on the facility at quarter end, leaving approximately $60 million of undrawn availability on the facility. During the semi-annual borrowing base review, the maturity date of the credit facility was extended to May 26, 2017. Pricing remained the same and there were no material changes made to the credit facility conditions or covenants. The next semi-annual borrowing base review by credit facility lenders is scheduled for October 16, 2015.

As of March 31, 2015, the Trust had approximately $60 million ($US 47.3 million) of unused credit on its now current $108 million ($US 85 million) revolving credit facility, which is held indirectly through its subsidiaries with a syndicate of Canadian chartered banks.

Working capital

At March 31, 2015, the Trust had a working capital surplus, excluding non-cash unit-based payments and non-cash risk management asset, of approximately $11.7 million and $47.7 million ($US 37.6 million) drawn on its bank credit facility described above.

Unitholders' equity

Commencing with the January 2015 distribution paid on February 23, 2015, the Trust suspended the regular distribution reinvestment component of the DRIP and no material Trust capital issuances therefore occurred during the first quarter.

For the one year period commencing January 21, 2015 and ending January 20, 2016, the Trust initiated a Normal Course Issuer Bid ("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.

During the first quarter of 2015, the Trust had purchased for cancellation 30,300 units at a weighted average market price of $1.94 per unit pursuant to the NCIB.

A summary of the number of units issued, proceeds resulting from the issuance of units and average price per unit resulting from the DRIP and units purchased and cancelled under the NCIB at March 31, 2015, December 31, 2014 and March 31, 2014 were as follows:

		Three Months Ended March 31, 2015		Year Ended December 31, 2014		Three Months Ended March 31, 2014
Number of units issued under the DRIP		36,552		2,868,203		687,356
Fair market value of units issued under the DRIP	$	-	$	2,319	$	-
Net proceeds from issuance of Trust capital (000's)	$	67	$	17,421	$	5,241
Average price per unit issued under the DRIP		1.84	$	6.07	$	7.63
Number of trust units cancelled pursuant to the NCIB		(30,300)		-		-
Reduction of Trust capital pursuant to the NCIB (000's)	$	(292)	$	-	$	-
Average price per unit cancelled pursuant to the NCIB	$	1.94	$	-	$	-

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

Distributions and outstanding unit data

The Trust pays monthly distributions to unitholders at the discretion of the Board of Directors. Commencing with the distribution paid on January 23, 2015, the Trust took action to protect its balance sheet in light of current and expected commodity prices by lowering its monthly distribution from $0.0875 to $0.03 per unit per month. Cash distributions paid in the first quarter (for the December 2014, and January and February 2015 record dates) totaled approximately $3.2 million.

At March 31, 2015, the Trust had issued 35,023,364 units (December 31, 2014 – 35,017,112; March 31, 2014 – 32,836,265).

As at the date of this MD&A, 34,997,364 units are issued and 3,241,750 options are outstanding.

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

(000's)	Three Months Ended March 31, 2015 $	Three Months Ended March 31, 2014 $
Earnings for the period	5,477	2,218
Cash distributions paid	(3,153)	(8,495)
Excess (shortfall) of earnings over cash distributions paid	**2,324**	(6,277)
Funds flow from operations[1]	7,727	10,341
Changes in operating working capital	(5,408)	373
Net cash provided by operating activities	2,319	10,714
Cash distributions paid	(3,153)	(8,495)
Excess (shortfall) of net cash provided by operating activities over cash distributions paid	**(834)**	2,219

Note:

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

For the three months ended March 31, 2015, earnings exceeded cash distributions paid for the period. For the three months ended March 31, 2014, cash distributions paid exceeded earnings. 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, and are required to be fair valued at each period end. Examples of non-cash items include depreciation, depletion and amortization, unit-based compensation, foreign exchange impact on intercompany loans, and unrealized risk management gains and losses, all of which have no impact on cash available to pay distributions.

For the three months ended March 31, 2015, cash distributions paid exceeded net cash provided by operating activities by $0.9 million, but funds flow from operations (before changes in working capital) exceeded cash distributions paid by approximately $4.6 million. For the three months ended March 31, 2014, net cash provided by operating activities exceeded cash distributions paid.

Capital expenditures

Capital expenditures during the three months ended March 31, 2015 and March 31, 2014 were as follows:

(000's)	Three Months Ended March 31, 2015 $	Three Months Ended March 31, 2014 $
Exploration and evaluation[1]	-	16
Acquisition - Hardeman	-	5,310
Intangible drilling and completions	1,964	9,018
Seismic	-	2,200
Well equipment and facilities	1,096	283
Other	-	11
	$ 3,060	$ 16,838

Note:

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

Refer to the "Segmented operations" section of this MD&A for a discussion of these capital expenditures.

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]	2,404	793	1,611	-
Total contractual obligations	**$ 2,404**	**$ 793**	**$ 1,611**	**$ -**

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 34 months and approximately $1.4 million remaining at March 31, 2015.

(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 33 months and approximately $US 0.8 million remaining at March 31, 2015. 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 1.27.

Non-IFRS financial measures

Statements throughout this MD&A make reference to the terms "field netback", "funds flow from operations", "corporate payout ratio" and "free cash flow", which are non-IFRS financial measures that do not have a standardized meaning prescribed by IFRS and may not 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.

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

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 condensed consolidated interim financial statements:

(000's)		**Three Months Ended March 31, 2015**		Three Months Ended March 31, 2014
Earnings (loss)	**$**	**5,477**	$	2,218
Add back (deduct) items not involving cash:				
Unit-based compensation – non-cash portion		(180)		(2,040)
Unrealized risk management loss (gain)		4,183		1,308
Depreciation, depletion and amortization and Impairment		6,170		8,736
Finance expense		201		119
Foreign exchange loss (gain) on intercompany loan		(8,124)		
Funds flow from operations	**$**	**7,727**	$	10,341
Add back (deduct) items not directly related to field operations:				
Realized foreign exchange loss (gain)		224		43
Finance expense (cash portion)		571		758
Risk management (gain) loss-realized		(7,295)		842
Administrative expenses		2,460		2,555
Cash settled award payments		57		166
Field netback	**$**	**3,744**	$	14,705

No change in internal controls over financial reporting and disclosure controls and procedures during the period January 1, 2015 to March 31, 2015

During the period beginning on January 1, 2015 and ended on March 31, 2015, there was no change in the Trust's internal controls over financial reporting and disclosure controls and procedures that has materially affected, or is reasonably likely to materially affect, the Trust's internal controls over financial reporting and disclosure controls and procedures. 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.

Critical accounting estimates

There have been no changes to the Trust's critical accounting estimates and judgments in the first quarter of 2015. Further information about the Trust's critical accounting estimates and judgments can be found in the notes to the consolidated financial statements and MD&A for the year ended December 31, 2014.

Accounting standards and interpretations

The accounting policies followed in these condensed consolidated interim financial statements are consistent with those of the previous financial year.

There were no new or amended standards issued during the three months ended March 31, 2015 that are applicable to the Trust in future periods. Additional adjustments to the Trust's accounting policies may be required upon completion of a separate IASB framework for extractive industries.

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.

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

- the Trust's 2015 capital budget and specific uses;
- the Trust's expectations regarding its 2015 full year average working interest production, operating costs and field netbacks;
- the Trust's expectations regarding its 2015 funds flow from operations, corporate payout ratio and debt to trailing cash flow, and sensitivities of these metrics to production rates, exchange rates and commodity prices;
- estimated corporate decline rates, sustaining capital and future development costs associated with reserves;
- anticipated crude oil, natural gas liquids and natural gas production levels;
- the Trust's expectations regarding production from the Dixonville property during the second quarter of 2015;
- projected debt to cash flow, and management's objective to maintain a debt to cash flow ratio below 2.0 times; and
- the Trust's belief that its expected funds flow from operations and undrawn credit facility will be sufficient to fund its current and expected financial obligations.

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

- future oil, natural gas liquid and natural gas 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 distribution levels;
- future capital expenditures and the ability of the Trust to obtain financing on acceptable terms for its capital projects and future acquisitions;
- 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;
- estimates of anticipated future 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; and
- projected operating costs, which are based on historical information and anticipated increases in the cost of equipment and services.

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 those in the AIF:

- volatility of oil, natural gas liquid, and natural gas prices;
- 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; 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 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. The Trust's production rates, operating costs, field netbacks, drilling program, 2015 capital budget, funds flow from operations, and distributions are subject to change in light of ongoing results, prevailing economic circumstances, obtaining regulatory approvals, commodity prices 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

Interim Condensed Consolidated Financial Statements
(in Canadian dollars) (unaudited)

For the three months ended March 31, 2015 and March 31, 2014

Eagle Energy Trust

Condensed Consolidated Balance Sheets

(Thousands of Canadian dollars) (unaudited)

	Note		March 31, 2015		December 31, 2014
ASSETS					
Current assets					
Cash		$	10,646	$	11,127
Trade and other receivables			8,383		6,669
Prepaid expenses			410		530
Risk management asset	3		12,020		14,919
			31,459		**33,245**
Non-current assets					
Oil and gas properties	9		232,833		222,939
Property, plant and equipment			198		219
Other intangible assets			852		769
			233,883		**223,927**
Total Assets		**$**	**265,342**	**$**	**257,172**
LIABILITIES					
Current liabilities					
Trade and other payables		$	6,435	$	8,316
Distributions payable			1,051		1,068
Unit-based payments	5		1,156		1,336
			8,642		**10,720**
Non-current liabilities					
Debt	10		47,650		47,200
Deferred income tax	7		-		-
Decommissioning liability	11		13,185		10,347
			60,835		**57,547**
Total Liabilities		**$**	**69,477**	**$**	**68,267**
UNITHOLDERS' EQUITY					
Trust capital	12	$	316,925	$	317,150
Currency reserves			34,104		29,494
Accumulated loss			(35,714)		(41,424)
Accumulated cash distributions	13		(119,450)		(116,315)
Total Unitholders' Equity		**$**	**195,865**	**$**	**188,905**
Total Liabilities and Unitholders' Equity		**$**	**265,342**	**$**	**257,172**

The notes are an integral part of these condensed financial statements.

See note 14 “Commitments” and note 15 “Subsequent events”.

Eagle Energy Trust

Condensed Consolidated Statements of Earnings and Comprehensive Income

(Thousands of Canadian dollars, except per unit amounts) (unaudited)

	Note		Three Months Ended March 31, 2015		Three Months Ended March 31, 2014- Revised[1]
Revenue		$	13,393	$	26,069
Royalties			(3,671)		(7,096)
			9,722		**18,973**
Operating expenses			5,938		4,072
Transportation and marketing expenses			40		196
Administrative expenses			2,460		2,555
Depreciation, depletion and amortization			6,170		8,736
Operating profit (loss)			**(4,886)**		**3,414**
Unit based compensation recovery	5		(123)		(1,874)
Finance expense	6		772		877
Risk management loss (gain)	3		(3,112)		2,150
Foreign exchange loss net			224		43
Foreign exchange gain on intercompany loan			(8,124)		-
Earnings before taxes			**5,477**		**2,218**
Income tax expense (recovery)	7		-		-
Earnings		**$**	**5,477**	**$**	**2,218**
Other comprehensive earnings					
Items that may be reclassified subsequently to earnings					
Foreign currency translation gain			4,610		9,744
Comprehensive income		**$**	**10,087**	**$**	**11,962**
Earnings per unit					
Basic	8	**$**	**0.16**	**$**	**0.07**
Diluted	8	**$**	**0.16**	**$**	**0.02**

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

The notes are an integral part of these condensed financial statements.

Eagle Energy Trust

Condensed Consolidated Statements of Changes in Unitholders' Equity

For the three months ended March 31, 2015 and March 31, 2014
(Thousands of Canadian dollars) (unaudited)

	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, 2013		**32,149**	**297,447**	**11,100**	**6,604**	**(80,454)**	**(73,850)**	**$ 234,697**
Earnings	8	-	-	-	2,218	-	2,218	2,218
Foreign currency translation gain		-	-	9,744	-	-	-	9,744
Total comprehensive earnings		-	-	9,744	2,218	-	2,218	11,962
Issuance of trust capital		687	5,241	-	-	-	-	5,241
Trust unit issuance costs		-	(45)	-	-	-	-	(45)
Unitholder distributions		-	-	-	-	(8,555)	(8,555)	(8,555)
			5,196	-	-	(8,555)	(8,555)	(3,359)
Balance at March 31, 2014		**32,836**	**302,643**	**20,844**	**8,822**	**(89,009)**	**(80,187)**	**$ 243,300**
Balance at December 31, 2014		**35,017**	**317,150**	**29,494**	**(41,424)**	**(116,315)**	**(157,739)**	**188,905**
Earnings	8	-	-	-	5,477	-	5,477	5,477
Foreign currency translation gain		-	-	4,610	-	-	-	4,610
Total comprehensive earnings		-	-	4,610	5,477	-	5,477	10,087
Issuance of trust capital	12	36	67	-	-	-	-	67
Cancellation of trust capital pursuant to NCIB	12	(30)	(292)	-	233	-	233	(59)
Trust unit issuance costs	12	-	-	-	-	-	-	-
Unitholder distributions	13	-	-	-	-	(3,135)	(3,135)	(3,135)
		6	(225)	-	233	(3,135)	(2,902)	(3,127)
Balance at March 31, 2015		**35,023**	**316,925**	**34,104**	**(35,714)**	**(119,450)**	**(155,164)**	**195,865**

The notes are an integral part of these condensed financial statements.

Eagle Energy Trust

Condensed Consolidated Cash Flow Statements

For the three months ended March 31, 2015 and March 31, 2014
(Thousands of Canadian dollars) (unaudited)

	Note		**Three Months Ended March 31, 2015**		Three Months Ended March 31, 2014
Cash flows from operating activities					
Earnings		**$**	5,477	$	2,218
Adjustments for non-cash items:					
Depreciation, depletion and amortization			6,170		8,736
Unit-based compensation – non-cash portion			(180)		(2,040)
Unrealized risk management loss			4,183		1,308
Foreign exchange gain on intercompany loan			(8,124)		
Finance expense			201		119
			7,727		10,341
Changes in working capital:					
Trade and other receivables			(1,149)		(411)
Prepaid expenses			155		72
Trade and other payables			(4,414)		712
			(5,408)		373
Net cash generated by operating activities		**$**	**2,319**	$	**10,714**
Cash flows from investing activities					
Exploration and evaluation			-		(16)
Oil and gas properties			(3,059)		(11,500)
Property, plant and equipment			(1)		(12)
Acquisition of oil and gas assets			-		(5,310)
Change in non-cash working capital			2,535		2,363
Net cash generated by (used in) investing activities		**$**	**(525)**	**$**	**(14,475)**
Cash flows from financing activities					
Debt			450		5,634
Proceeds from issuance of units			67		5,241
Purchase of trust units for cancellation			(59)		-
Trust unit issue costs			-		(45)
Cash distributions to unitholders			(3,153)		(8,495)
Deferred financing charges			(176)		-
Change in non-cash working capital			-		(145)
Net cash generated by (used in) financing activities		**$**	**(2,871)**	**$**	**2,190**
Net increase (decrease) in cash and cash equivalents			**(1,077)**		**(1,571)**
Effects of exchange rates on cash and cash equivalents			596		136
Cash at beginning of the period			11,127		1,435
Cash at end of the period		**$**	**10,646**	**$**	**-**

The notes are an integral part of these condensed financial statements.

Eagle Energy Trust

Notes to Condensed Consolidated Financial Statements (unaudited)

For the three months ended March 31, 2015 and March 31, 2014
(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.

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 March 31, 2015 was $US 1 equal to $CA 1.27 (December 31, 2014 - $US 1 equal to $CA 1.16), and the average foreign exchange rate for the three months ended March 31, 2015 was $US 1 equal to $CA 1.24 (for the three months ended March 31, 2014 - $US 1 equal to $CA 1.10).

Basis of accounting

The condensed consolidated interim financial statements were authorized for issue in accordance with a resolution of the Board of Directors made on May 7, 2015.

These condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including IAS 34, Interim Financial Reporting and have been prepared following the same accounting policies as the annual audited IFRS Consolidated Financial Statements for the year ended December 31, 2014, except for income tax expense for an interim period which is based on an estimated average annual effective income tax rate. The condensed consolidated interim financial statements should be read in conjunction with the annual financial statements for the year ended December 31, 2014, which have been prepared in accordance with IFRS as issued by the IASB.

2.2. Changes in accounting policy and disclosures

The accounting policies followed in these condensed consolidated interim financial statements are consistent with those of the previous financial year.

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 of 2014, 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 restated its revenue and transportation and marketing expense for the prior year comparative period to reflect this adjustment.

For the three months ended March 31, 2014, the impact of the oil transportation restatement to both revenue and transportation and marketing expenses was a $0.5 million reduction.

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.

A description of accounting policies and disclosures that were adopted by the Trust can be found in the notes to the annual consolidated financial statements for the year ended December 31, 2014. Additional adjustments to the Trust's accounting policies may be required upon completion of a separate IASB framework for extractive industries.

3. Financial risk management and financial instruments

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 changes in the Trust's exposure to each of the above risks since the year ended December 31, 2014.

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 Trust limits its exposure, in this regard, by investing only in liquid securities and only with counterparties with a strong credit rating.

At March 31, 2015, there was no material change in credit risk compared to the year end.

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 March 31, 2015, there was no material change in the contractual undiscounted cash outflow for financial liabilities compared to year end.

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 Positions

As at March 31, 2015, the Trust has 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)	190	bbls/d	Jan-15	Dec-15	85.40	85.40	2,174	-
NYMEX (ii)	1,000	bbls/d	Jan-15	Jun-15	90.10	92.00	4,654	-
NYMEX (i)	400	bbls/d	Jul-15	Dec-15	87.90	87.90	3,164	-
NYMEX (ii)	400	bbls/d	Jan-15	Jun-15	90.50	94.35	1,880	-
NYMEX (i)	500	bbls/d	Jul-15	Sep-15	55.45	55.45	148	-
Commodity - unrealized risk management position							12,020	-

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

Reconciliation of Net Management Positions

	March 31, 2015		December 31, 2014	
$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	$ 14,919	$ 14,919	$ (1,453)	$ (1,453)
Fair value of contracts realized during the period	(7,295)	(7,295)	149	149
Fair value of contracts unrealized during the period	4,183	4,183	15,718	15,718
Effects of exchange rate	213	213	505	505
Fair value of contracts	**$ 12,020**	**$ 12,020**	$ 14,919	$ 14,919

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

	March 31, 2015			March 31, 2014		
$000's	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)
Net effect - commodity	(7,295)	4,183	(3,112)	818	1,114	1,932
Net effect - foreign exchange	-	-	-	24	194	218
Net effect - risk management	**$ (7,295)**	**4,183**	**(3,112)**	$ 842	$ 1,308	$ 2,150

Determination of fair values

The net fair value of Eagle's unrealized risk management positions at March 31, 2015 is an asset of $12.0 million (December 31, 2014 - $14.9 million asset). The carrying value of the Trust's risk management position has been calculated using both quoted prices in active markets and observable market-corroborated data consistent with a Level 2 valuation.

The fair values of cash, trade and other receivables, trade and other payables and distributions payable approximate their carrying amount due to the short-term maturity of those instruments.

Debt is a financial liability with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest rate method. The carrying value of the Trust's debt is equal to the fair value and the determination of the fair value of the debt is consistent with a level 2 valuation.

4. Segmented information

The Trust's operating activities relate solely to the exploration, development and production of petroleum and natural gas resources in the United States and Canada. Costs incurred in the Corporate segment relate to the Trust's hedging program, public company, and other expenses incurred in overall financing and administration of the Trust.

Eagle's management reviews 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.

Details of the Trust's reportable segments at March 31, 2015 are as follows:

	Three months ended March 31, 2015			
$000's	Canada	United States	Corporate	Total
Risk management asset	-	-	12,020	12,020
Oil and gas properties and Property, plant and equipment	111,724	121,307	-	233,031
Other assets	26	20,265	-	20,291
Total assets	**$ 111,750**	**$ 141,572**	**$ 12,020**	**$ 265,342**
Revenue	3,791	9,602	-	13,393
Royalties	(869)	(2,802)	-	(3,671)
Revenue, net of royalties	2,922	6,800	-	9,722
Operating expenses	2,082	3,856	-	5,938
Transportation and marketing expenses	9	31	-	40
	$ 831	**$ 2,913**	**$ -**	**$ 3,744**
Administrative expenses	46	1,906	508	2,460
Cash settled award payments	-	-	57	57
Risk management loss (gain) - realized	-	-	(7,295)	(7,295)
Finance expense (cash portion)	-	-	571	571
Realized foreign exchange loss (gain)	-	-	224	224
Funds flow from operations	**$ 785**	**$ 1,007**	**$ 5,935**	**$ 7,727**

Reconciliation of funds flow from operations to net earnings (loss) for each reportable segment is as follows:

	Three months ended March 31, 2015			
$000's	Canada	United States	Corporate	Total
Funds flow from operations	**$ 785**	**$ 1,007**	**$ 5,935**	**$ 7,727**
Unit based compensation - non-cash portion	-	-	(180)	(180)
Risk management loss (gain) - unrealized	-	-	4,183	4,183
Depreciation, depletion and amortization	1,284	4,886	-	6,170
Foreign exchange gain on intercompany loan	-	-	(8,124)	(8,124)
Finance expense (non-cash portion)	-	-	201	201
Earnings (loss)	**$ (499)**	**$ (3,879)**	**$ 9,855**	**$ 5,477**

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

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

The Canadian segment arose due to the acquisition of the Dixonville property on December 18, 2014. The effective date of the acquisition was January 1, 2015 therefore the Trust did not disclose its operating activities by segment at December 31, 2014.

The exchange rate in effect at December 31, 2014 was $US 1 equal to $CA 1.16.

5. Unit-based payments

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

$ 000's	Note	**Three Months Ended March 31, 2015**	Three Months Ended March 31, 2014
Restricted unit rights	5(a)	6	(379)
Unit options	5(b)	28	(1,425)
Unit rights	5(c)	(157)	(70)
Total unit-based compensation expense (recovery)		**$ (123)**	$ (1,874)

The following table reconciles the unit-based payments liability.

$ 000's	Note	**March 31, 2015**	December 31, 2014
Restricted unit rights	5(a)	9	61
Unit options	5(b)	960	932
Unit rights	6(c)	187	343
Total unit-based payments liability		**$ 1,156**	$ 1,336

Note (a)

Cash settled Restricted Unit Rights (RURs) issued upon surrender of performance options

For the three months ended March 31, 2015, $56,925 has been paid to the RUR holders (year ended December 31, 2014 - $664,072, three months ended March 31, 2014 – $166,037).

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

	Three Months Ended March 31, 2015	Year Ended December 31, 2014	Three Months Ended March 31, 2014
Balance, beginning of period	632,500	632,500	632,500
Issued	-	-	-
Forfeited	-	-	-
Balance, end of period	632,500	632,500	632,500
Number of RURs vested	632,500	632,500	632,500

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

	March 31, 2015	December 31, 2014	March 31, 2014
Fair value at the balance sheet date	$ 0.11	$ 0.10	$ 5.09
Volatility	35%	36%	27%
Life of RURs	5.8 years	6.0 years	6.8 years
Risk-free interest rate	1.37%	1.83%	2.46%

A forfeiture rate of 5% was used, which is an estimated expected rate. The expected unit price volatility was calculated using the trading history of the Trust's units.

Note (b)

Unit option plan

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

	Three Months Ended March 31, 2015		Year Ended December 31, 2014		Three Months Ended March 31, 2014	
	Number of options	**Weighted average exercise price**	Number of Options	Weighted average exercise price	Number of Options	Weighted average exercise price
Outstanding, beginning of period	3,431,750	$ 5.94	3,126,750	$ 7.05	3,126,750	$ 7.05
Forfeited	(93,332)	1.82	(45,000)	5.51	-	-
Exercised	-	-	-	-	-	-
Granted	-	-	350,000	5.35	50,000	8.31
Outstanding at end of period	**3,338,418**	**$ 5.70**	3,431,750	$ 5.94	3,176,750	$ 6.81
Exercisable at end of period	**2,125,762**	**$ 5.71**	2,109,095	$ 6.01	1,425,176	$ 6.75

The range of exercise prices of the outstanding options is as follows at March 31, 2015:

	Weighted average exercise price	Weighted average contractual life (years)
$4.78- $7.43	**$ 5.70**	**7.3**

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

	March 31, 2015	December 31, 2014	March 31, 2014
Fair value - at balance sheet date	$ 0.37	$ 0.37	$ 2.69
Unit trading price - closing	$ 2.41	$ 2.33	$ 7.13
Exercise price – weighted average	$ 5.70	$ 5.94	$ 6.81
Volatility	35%	36%	27%
Option life – weighted average	7.3 years	7.6 years	8.1 years
Distributions – none estimated, due to declining strike price feature	0%	0%	0%
Risk-free interest rate	1.37%	1.83%	2.46%

A forfeiture rate of 5% was used, which is an estimated expected rate. This estimate will be adjusted to the actual forfeiture rate. The expected unit price volatility was calculated using the trading history of the Trust's units.

Note (c)

Unit Rights (URs) plan

For the three months ended March 31, 2015, $nil has been paid to the UR holders (year ended December 31, 2014 - $29,573, three months ended March 31, 2014 - $nil).

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

	Three Months Ended March 31, 2015	Year Ended December 31, 2014	Three Months Ended March 31, 2014
Balance, beginning of period	937,000	997,000	997,000
Issued	-	-	-
Forfeited	(197,500)	(60,000)	-
Balance, end of period	739,500	937,000	997,000
Number of unit rights vested	**340,839**	465,007	169,336

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:

	March 31, 2015	December 31, 2014	March 31, 2014
Fair value at the balance sheet date	$ 0.32	$ 0.50	$ 3.57
Volatility	35%	36%	27%
Life of restricted URs	8.0 years	8.1 years	8.9 years
Risk-free interest rate	1.37%	1.83%	2.46%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. The expected unit price volatility was calculated using the trading history of the Trust's units.

6. Finance expense

$ 000's	**Three Months Ended March 31, 2015**	Three Months Ended March 31, 2014
Interest expense on debt	$ 488	$ 753
Amortization of deferred financing costs	134	96
Standby and bank fees	82	5
Accretion of decommissioning provision	68	23
Finance expense	**$ 772**	$ **877**

7. Taxation

Reconciliation of effective tax rate

The income tax provision differs from the amount that would have been expected if the reported earnings had been subject only to the statutory Canadian income tax rate of 25% (2014, U.S. Federal and state combined rate of 35%) as follows:

$ 000's	**Three Months Ended March 31, 2015**	Three Months Ended March 31, 2014
Earnings before taxation	$ 5,477	$ 2,218
Expected tax rate	25%	35%
Expected income tax provision (recovery)	1,369	776
Decrease (Increase) resulting from:		
Non-deductible items – permanent differences		
Administrative expenses of the Trust	138	322
Unit-based compensation	(17)	(656)
Foreign exchange gain, net	(4,693)	(214)
Foreign tax rate differentials[(1)]	(359)	-
Changes in temporary differences for which no amounts are recognized	4,148	1,133
Items deductible at the subsidiary level		
Interest on internal debt of subsidiary	(606)	(1,364)
Other	20	3
Total income tax expense (recovery)	**$ -**	$ -

(1) Combined tax rate is 25% in Canada and 35% in the United States.

Deferred tax assets and liabilities:

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

$ 000's	**March 31, 2015**	December 31, 2014
Deferred tax liabilities		
Oil and gas properties in excess of tax value	$ 4,367	$ 3,422
Less deferred tax assets:		
Non-capital losses	(37,343)	(32,216)
Net deferred tax liability (asset) – before valuation allowance	(32,976)	(28,794)
Unrecognized deferred tax asset	32,976	28,794
Net deferred tax liability (asset)	**$ -**	$ -

The U.S. and Canadian tax losses can be utilized for 20 years and start to expire in 2030 and 2034 respectively. Deferred tax assets have not been recognized in respect of these tax losses, as there is not sufficient certainty regarding the future utilization.

8. Earnings per unit

$ 000's		Three Months Ended March 31, 2015		Three Months Ended March 31, 2014
Earnings attributable to unitholders (basic)	$	5,477	$	2,218
Earnings attributable to unitholders (diluted)	$	5,477	$	793
Weighted average number of units outstanding (basic)		35,032		32,427
Weighted average number of units outstanding (diluted)		35,032		35,266
Earnings per unit (basic)	**$**	**0.16**	$	0.07
Earnings per unit (diluted)	**$**	**0.16**	$	0.02

9. Oil and gas properties

$ 000's		Developed oil and gas assets		Production facilities and equipment		Impairment		Total
Cost								
At December 31, 2014	$	445,606	$	8,086	$	-	$	453,692
Additions		4,801		824		-		5,625
Effects of foreign exchange		27,751		734		-		28,485
At March 31, 2015	**$**	**478,158**	**$**	**9,644**	**$**	**-**	**$**	**487,802**
Accumulated depreciation, depletion and amortization								
At December 31, 2014	$	(170,083)	$	(5,721)	$	(54,949)	$	(230,753)
Depreciation		(5,618)		(304)		-		(5,922)
Effects of foreign exchange		(12,753)		(543)		(4,998)		(18,294)
At March 31, 2015	**$**	**(188,454)**	**$**	**(6,568)**	**$**	**(59,947)**	**$**	**(254,969)**
Net book value								
At December 31, 2014	$	275,523	$	2,365	$	(54,949)	$	222,939
Net change for the period		14,181		711		(4,998)		9,894
At March 31, 2015	**$**	**289,704**	**$**	**3,076**	**$**	**(59,947)**	**$**	**232,833**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $ 42.0 million (December 31, 2014 - $ 42.9 million) were included in the depletion calculation.

10. Debt

As a result of the Dixonville acquisition and expansion of the banking syndicate, Eagle's credit facility was further expanded to $US 95 million on February 11, 2015. 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.

See note 15 "Subsequent events". Eagle has renewed its credit facility at $US 85 million, previously $US 95 million, realizing annual savings of more than $80,000 through reduced commitment and extension fees. Eagle was only 35% drawn on the facility at quarter end, leaving approximately $60 million of undrawn availability on the facility. During the semi-annual borrowing base review, the maturity date of the credit facility was extended to May 26, 2017. Pricing remained the same and there were no material changes made to the credit facility conditions or covenants. The next semi-annual borrowing base review by credit facility lenders is scheduled for October 16, 2015.

For the three months ended March 31, 2015, the interest rate on the revolving credit facility was approximately 4.2%. At March 31, 2015, there were no covenant violations under or in connection with the credit facility.

At March 31, 2015, details of the Trust's credit facility are as follows:

$000's		$US		$CA
Authorized (revolving)	$	95,000		120,327
Less:				
Amounts drawn		37,620		47,650
Available	**$**	**57,380**	**$**	**72,677**

The exchange rate in effect at March 31, 2015 was $US 1 equal to $CA 1.27. The amount drawn on the credit facility at March 31, 2015 was denominated in Canadian funds.

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 was denominated in Canadian funds.

11. Decommissioning liability

$000's		**Three Months Ended March 31, 2015**		Year Ended December 31, 2014
Beginning balance	$	10,347	$	3,036
Acquisition		-		472
Additions		-		344
Changes in estimates		2,521		7,981
Disposition		-		(1,189)
Abandonment expenditures		-		(212)
Accretion (unwinding of discount)		68		78
Effects of exchange rate		249		(163)
Ending balance	**$**	**13,185**	$	10,347

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 2.0% annual inflation rate), and discounted using a risk-free discount rate at March 31, 2015 of 1.3% for the Salt Flat properties, 2% for the Hardeman properties and 2% for the Dixonville properties (December 31, 2014 – 2% for Salt Flat, 2.7% for Hardeman, 2.7% for Dixonville).

12. Trust capital

Trust units outstanding

	Three Months Ended March 31, 2015			Year Ended December 31, 2014		
$000's	Number of units		Amount	Number of units		Amount
Beginning balance	35,017	$	317,150	32,149	$	297,447
Issuance on Trust capital pursuant to DRIP	36		67	2,868		17,421
Cancellation of Trust capital pursuant to NCIB	(30)		(292)	-		-
Fair value adjustment	-		-	-		2,319
Trust unit issuance costs	-		-	-		(37)
Ending balance	**35,023**	**$**	**316,925**	**35,017**	**$**	**317,150**

For the three months ended March 31, 2015, the Trust incurred $nil (December 31, 2014 - $37,099) of unit issuance costs in conjunction with the DRIP.

For 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.

On January 19, 2015, the Trust 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.

Additionally, Eagle 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

For the three months ended March 31, 2015, the Trust has purchased and cancelled 30,300 units at a weighted average market price of $1.94 per unit pursuant to the NCIB.

13. Accumulated cash distributions

$ 000's		March 31, 2015		December 31, 2014
Beginning balance	$	(116,315)	$	(80,454)
Accumulated cash distributions		(3,153)		(33,524)
Fair market value of units issued under the DRIP		18		(2,337)
Total accumulated cash distributions	**$**	**(119,450)**	$	(116,315)

In accordance with IFRS 13, at March 31, 2015, the Trust recorded a non-cash fair value adjustment of $17,921 (March 31, 2014 - $nil) for units issued under the DRIP.

14. 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 34 months and approximately $1.4 million remaining at March 31, 2015.

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 33 months and approximately $US 0.8 million remaining at March 31, 2015. 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 1.27.

15. Subsequent events

Risk management

On April 10, 2015, the Trust entered into the following financial contracts to further mitigate the effects of fluctuating prices on a portion of its production:

- a fixed price financial swap to sell 200 barrels of oil per day with a July 2015 through September 2015 term at a fixed price of $US 55.60 WTI per barrel.

- a fixed price financial swap to sell 400 barrels of oil per day with a October 2015 through December 2015 term at a fixed price of $US 57.10 WTI per barrel.

Credit Facility

Eagle has renewed its credit facility at $US 85 million, previously $US 95 million, realizing annual savings of more than $80,000 through reduced commitment and extension fees. Eagle was only 35% drawn on the facility at quarter end, leaving approximately $60 million of undrawn availability on the facility. During the semi-annual borrowing base review, the maturity date of the credit facility was extended to May 26, 2017. Pricing remained the same and there were no material changes made to the credit facility conditions or covenants. The next semi-annual borrowing base review by credit facility lenders is scheduled for October 16, 2015.

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

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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

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