VISION GROWTH INCOME

First Quarter 2014 Financial Report

EAGLE ENERGY™
TRUST

Management's Discussion and Analysis

May 9, 2014

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 9, 2014, 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, 2014 ("**Interim Financial Statements**") and the Trust's audited consolidated financial statements and accompanying notes and related MD&A for the year ended December 31, 2013 and the Trust's Annual Information Form dated March 20, 2014 ("**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.

This MD&A contains information that is forward-looking. Investors should read the "Note about forward-looking statements" section at the end of this MD&A.

Overview of the Trust

Eagle 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 strategy is to invest in operating subsidiaries that will acquire onshore petroleum reserves and production with unexploited low risk development potential, located in certain regions of the U.S., and to pay out a portion of available cash to unitholders of the Trust on a monthly basis. The Trust provides investors with a publicly traded, petroleum focused, distribution producing investment, with favourable tax treatment relative to taxable Canadian corporations.

The Trust was formed on July 20, 2010, but did not commence active operations until November 24, 2010, the date of its initial public offering. During November and December 2010, the Trust raised $149.5 million, at an offering price of $10.00 per trust unit, through an initial public offering. Concurrent with closing its initial public offering the Trust acquired, indirectly through its wholly-owned subsidiary, an average 73% interest in the Salt Flat Field, a light oil property located near Luling in south central Texas, for $127.1 million. Consideration consisted of cash and 2,000,000 trust units valued at $20 million. In May 2012, the Trust closed a bought deal financing, including the proceeds from the exercise of the over-allotment option, of 8,680,000 trust units at a price of $11.00 per trust unit, for total proceeds of $95.5 million. Concurrent with closing this financing, Eagle acquired 92.5% of the seller's 99% interest in certain Permian Basin properties ("**Permian properties**"), located near Midland, Texas. After the closing, Eagle also acquired all of another party's 1% interest in the same properties. On April 22, 2013, the Trust acquired the remaining 7.5% of the seller's interest in the Permian properties. On November 25, 2013, the Trust acquired an approximate 90% working interest in certain producing properties in Hardeman County, Texas and subsequently acquired an additional 66%

working interest in certain producing properties in Hardeman County, Texas and Greer, Harmon and Jackson counties, Oklahoma on February 27, 2014.

Throughout this MD&A, Eagle Energy Trust and its subsidiaries are collectively referred to as “the Trust” for purposes of convenience. In addition, references to the results of operations refer to operations of the Trust’s U.S. subsidiary.

Highlights for the three months ended March 31, 2014

- Reported first quarter average working interest sales volumes of 3,010 barrels of oil equivalent per day (“boe/d”) (85% oil, 8% natural gas liquids, 7% natural gas) with production on track to meet 2014 full year guidance of 3,250 to 3,450 boe/d.
- Posted top-quartile first quarter field netbacks of $54.29 per boe up 14% from the fourth quarter of 2013. Canadian dollar realized oil prices were $109.19 per barrel (approximately $US 99.00 per barrel), giving Eagle a substantial revenue advantage over producers of Canadian oil.
- Generated first quarter funds flow from operations of $10.3 million, up 18% from the fourth quarter of 2013.
- Maintained first quarter unitholder distributions at $0.26 per unit ($0.0875 per unit per month).
- Increased the Trust’s presence in its most recently established core area in the Hardeman basin, through a small tuck-in acquisition of approximately 130 boe/d for cash consideration of $5.3 million ($US 4.7 million).
- Executed 55% of its $US 28 million capital program, is pleased with the results to date, and has kicked off additional programs to reduce operating costs.

Operations update

Hardeman Properties

Eagle added undeveloped acreage and additional production in its newly established Hardeman core area in February and completed in-depth well-by-well reviews in March.

In the field, Eagle recompleted one well in March, with results meeting expectations. Required land work is underway, which will permit several recompletions and the drilling of a salt water disposal well (to reduce field operating costs) in the second half of 2014.

Eagle purchased seismic data that is being evaluated and is expected to add several Chappell and Atoka formation drilling locations to Eagle’s inventory. The opportunity also exists to evaluate other zones, while primarily targeting the Chappell formation, during future drilling.

Plans are underway to reduce water disposal and power costs, which collectively comprise 80% of field operating costs. As of mid-April, Eagle has renegotiated water hauling rates and optimized water hauling routes. Eagle plans to drill a salt water disposal well to further reduce water disposal charges. Propane is utilized at wells that are remotely situated from the electricity grid. To reduce costs, Eagle acquired and repaired an inactive natural gas sharing system and recompleted a well to displace propane as fuel. Further initiatives include well-site electrification, the installation of additional natural gas sharing lines and movement of existing gas engines to further optimize fuel usage.

Permian Properties

Eagle recently drilled two vertical wells on its Permian properties. The first well has been completed, is currently flowing back and cleaning up, and is expected to commence commercial production in the second quarter. The second well is scheduled to be completed in the middle of the second quarter, with production expected to follow in the third quarter. Both wells have exceeded expectations from a cost control standpoint.

Eagle is encouraged by early results of its Permian vertical well recompletion program. To the end of the first quarter, eight recompletions have been performed, targeting two to four of the lower decline Permian Spraberry zones. As was planned, the eight existing producing wells had to be shut-in for approximately one month each while the well recompletion work took place and then had to “de-water”, but the temporary impact of lower first quarter production is more than offset by the incremental volumes.

Eagle continues to monitor Permian horizontal drilling activity on offset acreage while the play is being de-risked by other operators. Recent transaction values indicate that the play is highly prolific and could have significant upside for Eagle's Permian properties.

For the Permian area, the depth and deviation of vertical wells make them susceptible to parted rods or accelerated tubing wear. Tubing, pump and rod damage can occur due to abrasion and friction between these components. Recognizing this as an area where innovation and cost control is critical, Eagle has formulated a plan to understand and reduce such downtime, including: (1) gyro surveying the vertical wellbores such that more effective rods and rod guides can be designed for future repairs; (2) using local expertise to help diagnose problems including using continuous dynamometer recording; and (3) incorporating more resilient downhole materials. The implementation of these operating procedures should reduce overall operating costs in this area.

Eagle has negotiated a long term gas purchase contract with a new buyer. While natural gas and natural gas liquids do not comprise a large percentage of corporate production, this new contract enhances Eagle's ability to reliably deliver its product and increases product volumes because of a lower inlet line pressure for the gathering system.

Salt Flat Properties

Eagle drilled two horizontal oil wells on its Salt Flat properties in the first quarter of 2014. In addition, installation of pumps in the horizontal portion of eight existing wells to increase production rates and reserves was completed in April. To date, the Salt Flat capital program has met cost and production expectations.

Eagle plans to shoot proprietary seismic to identify additional drilling locations in the Edwards formation at Salt Flat.

Outlook

This outlook section is intended to provide unitholders with information about Eagle's expectations as at the date hereof for production and capital expenditures for 2014. 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 maintains its 2014 guidance previously provided in its MD&A for the year ended December 31, 2013. Eagle's guidance is as follows:

	2014 Guidance	Notes
Capital budget	$US 28.0 mm	(1)
Working interest production	3,250 – 3,450 boe/d	
Operating costs (inclusive of transportation)	$12.50 - $14.50 per boe	
Funds flow from operations	$49.1 mm	(2)

Notes:

(1) The capital budget amount includes the February 2014 tuck-in acquisition in Hardeman County for $US 4.7 million and associated production.

(2) 2014 funds flow from operations of $49.1 million has been estimated using the following assumptions:

a. average working interest production of 3,350 boe/d (being the midpoint of the guidance range);
b. pricing at $US 95.00 per barrel WTI oil, $US 3.35 per Mcf NYMEX gas and $US 33.25 per barrel NGLs (NGLs price is calculated as 35% of the WTI price);
c. differential to WTI (excluding transportation) of a discount of $US 1.17 per barrel for the Permian properties, $US 2.52 per barrel for the Salt Flat properties, and $US 2.40 per barrel for the Hardeman properties;
d. average operating costs (inclusive of transportation) of $13.50 per boe; and
e. foreign exchange rate of $CA 1.05 = $US 1.00.

A table showing the sensitivity of Eagle's funds flow to production and commodity pricing is set out below under the heading "2014 Sensitivities".

Calculations and commentary regarding the sustainability of Eagle's distributions

The following table sets out Eagle's 2014 guidance with respect to its projected payout ratios, debt to trailing cashflow and percentage drawn on its credit facility.

	2014 Guidance	Notes
Payout ratios (as a percentage of funds flow)		
Basic payout ratio (i.e., distribution)	72%	(1)
Plus: capital expenditures (excluding "E" capital)	52%	(2)
Equals: corporate payout ratio	123%	(3)
Adjusted payout ratio (i.e., distribution - DRIP proceeds + capital expenditures)	77%	(4)
Financial strength		
Debt to trailing cashflow	1.34x	(5)
% drawn on existing credit facility	78%	(5)

Notes:

(1) Eagle calculates its basic payout ratio as follows:

$$\frac{\text{Unitholder distributions}}{\text{Funds flow from operations}} = \text{Basic payout ratio}$$

A table showing the sensitivity of Eagle's basic payout ratio to production and pricing is set out below under the heading "2014 Sensitivities".

(2) Approximately $US 3.8 million of the 2014 capital budget will be directed towards land and seismic evaluation of opportunities in Eagle's areas of operation ("E" capital), and is excluded from this calculation.

(3) Eagle calculates its corporate payout ratio as follows:

$$\frac{\text{Capital expenditures + unitholder distributions}}{\text{Funds flow from operations}} = \text{Corporate payout ratio}$$

A table showing the sensitivity of Eagle's corporate payout ratio to production and pricing is set out below under the heading "2014 Sensitivities".

(4) Assumes 65% unitholder participation in Eagle's Premium DRIP™ and distribution reinvestment programs is unchanged throughout 2014. As is the case with any manner of equity funding, Eagle weighs the benefits of this method of financing and will make adjustments as deemed prudent.

(5) The total borrowing base under the credit facility is $US 90 million.

Underlying asset quality benchmarks

Based on 2014 guidance, Eagle's underlying asset base has the following inherent attributes:

Oil and Gas Fundamentals	2014 Guidance	Notes
Oil weighting	85%	
Gas weighting (@ 6 Mcf:1bbl)	6%	
NGL weighting	9%	
Operating expense	$12.50 to $14.50	(1)
Field netbacks	$52.00	(2)
% hedged	49%	(3)

Notes:

(1) Includes transportation.

(2) Assuming average operating costs (inclusive of transportation) of $13.50 per boe (being the mid-point of the guidance range).

(3) Hedging supports sustainability in a volatile commodity price environment (target 50%). 2014 hedges currently in place lock in an average of 1,650 barrels per day at WTI prices ranging from $US 90.00 to $US 98.00 per barrel.

2014 Sensitivities

The following tables show the sensitivity of Eagle's funds flow, corporate payout ratio and basic payout ratio to changes in commodity price and production.

Sensitivity of funds flow ($ millions) to commodity price and production

		2014 Average WTI		
		$US 90.00	$US 95.00	$US 100.00
2014 average working interest production (boe/d)	3,250	45.6	47.2	48.3
	3,350	47.4	49.1	50.4
	3,450	49.2	51.1	52.4

Sensitivity of corporate payout ratio to commodity price and production

		2014 Average WTI		
		$US 90.00	$US 95.00	$US 100.00
2014 average working interest production (boe/d)	3,250	132%	129%	125%
	3,350	128%	123%	120%
	3,450	123%	118%	115%

Sensitivity of basic payout ratio to commodity price and production

		2014 Average WTI		
		$US 90.00	$US 95.00	$US 100.00
2014 average working interest production (boe/d)	3,250	77%	74%	73%
	3,350	74%	72%	70%
	3,450	71%	69%	67%

Assumptions:

(1) Annual distributions are held at current levels of $1.05 per unit per year.

(2) No new equity issued other than distribution reinvestment program.

(3) Field operating costs (including transportation) of $13.50 per boe (being the mid-point of the guidance range).

(4) Approximately $US 3.8 million of the 2014 capital budget will be directed towards land and seismic evaluation of opportunities in Eagle's areas of operation, and is excluded from the corporate payout ratio calculation.

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	218	0.01
Gas production	+1000 mcf/d	260	0.01
Oil production	+100 bbls/d	591	0.02
Currency (2)	+CDN weaken by $0.01	198	0.01
Interest rate	+1% prime	(190)	(0.01)

Notes:

(1) Per unit figures are based on 32,427,365 weighted average basic units outstanding for the three months ended March 31, 2014.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate equal to year to date average working interest sales volumes of 3,010 boe/d.

Results of operations

Production

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013	%
Oil (bbl/d)	2,545	2,553	-
Natural gas (Mcf/d)	1,316	1,019	29
Natural gas liquids (bbl/d)	246	207	18
Oil equivalent sales volumes (boe/d @ 6:1)	3,010	2,928	3

Working interest sales volumes for the first quarter of 2014 averaged 3,010 boe/d (85% oil, 8% natural gas liquids, 7% natural gas).

Revenue

($000's)		**Three Months Ended March 31, 2014**		Three Months Ended March 31, 2013	%
Oil	$	25,011	$	22,412	12
Natural gas		587		320	83
Natural gas liquids		955		609	57
Sales before royalties	**$**	26,553	**$**	23,341	14

Realized Prices					
Oil ($/bbl)	$	109.19	$	97.55	12
Natural gas ($/Mcf)		4.96		3.49	42
Natural gas liquids ($/bbl)		43.24		32.63	33
Sales before royalties ($/boe)		98.02		88.57	11
Royalties ($/boe)		(26.19)		(24.80)	6
Revenue ($/boe)	**$**	71.83	**$**	63.77	13

Benchmark Prices					
Oil – WTI ($US/bbl)	**$**	98.68	**$**	94.35	5
Natural gas – Henry HUB ($US/Mcf)	**$**	4.73	**$**	3.34	42

The Trust's quarterly revenue is 98% derived from oil and natural gas liquids. Realized oil prices were essentially level with benchmark $US WTI for the quarter, while natural gas liquid prices were approximately 44% of benchmark $US WTI.

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. The Trust has acquired U.S. properties which are close to markets and, in so doing, realizes premium sales prices compared to producers of Canadian oil.

For the Salt Flat properties, field marketing contracts are in place which use Louisiana Light Sweet ("LLS") as a reference price instead of WTI. The January and February 2014 contract held all other field pricing adjustments fixed, but let the LLS-WTI differential float. For March and April, all other field pricing adjustments (except for a fixed per barrel marketing fee) and the LLS-WTI differential floated. For May through November, a contract is in place which holds all other field pricing adjustments fixed and lets the LLS-WTI differential float.

For the Permian properties, field marketing contracts are in place which use WTI as a reference price. The January and February 2014 contract held all other field pricing adjustments fixed. For March and April, all other field pricing adjustments floated (except for a fixed per barrel marketing fee). For May through November, a contract is in place which holds all other field pricing adjustments fixed and lets the Midland-Cushing differential float.

For the Hardeman properties, field marketing contracts are in place from May through November which use either WTI or NYMEX as a reference price. These contracts hold all other field pricing adjustments fixed.

Eagle will continue to monitor the spread on the floating price components and has the ability to fix these in the future.

The benchmark WTI price increased 5% from the prior year's comparative quarter with Canadian dollar realized prices increasing by a higher amount due to the weakening Canadian dollar. The above prices do not include realized gains or losses from financial commodity contracts, which amounted to a realized loss of $0.8 million ($3.02/boe) for the three months ended March 31, 2014. 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, 2014		Three Months Ended March 31, 2013		%
	$	**/boe**	$	/boe	
Operating expenses		15.03		9.04	66
Transportation expenses		2.51		2.14	17
	$	**17.54**	$	11.18	57

The 57% year-over-year increase in per boe operating costs is primarily due to salt water disposal costs on the Hardeman properties and tubing and pump rod replacements on the Permian properties due to wearing and corrosion. Refer to the "Operations update" section at the beginning of this MD&A where initiatives to reduce these costs are discussed. The Trust intends to continue to improve efficiencies and reduce operating costs and maintains its full year 2014 operating expense guidance of $12.50 to $14.50 per boe.

Depreciation, depletion and amortization

	Three Months Ended March 31, 2014		Three Months Ended March 31, 2013		%
	$	**/boe**	$	/boe	
Depreciation, depletion and amortization		**32.07**		27.34	17

The depletion, depreciation, and amortization provision for the three months ended March 31, 2014 was based on proved plus probable reserves, including the future development costs associated with those reserves, as outlined in the year-end 2013 reserves evaluation report prepared by the Trust's independent reserves evaluators.

Field netback

	Three Months Ended March 31, 2014		Three Months Ended March 31, 2013	
($000's)	**$**	**$ /boe**	$	$ /boe
Sales before royalties	26,553	98.02	23,341	88.57
Royalties	(7,096)	(26.19)	(6,536)	(24.80)
Operating expenses	(4,072)	(15.03)	(2,383)	(9.04)
Transportation expenses	(680)	(2.51)	(565)	(2.14)
Field netback	**$** 14,705	**$** 54.29	$ 13,857	$ 52.59
Sales volumes (boe/d)		**3,010**		2,928

During the quarter, benchmark WTI averaged $US 98.68 per barrel and the Trust realized a field netback of $54.29 per boe. On a year-over-year basis, higher realized prices were largely offset by increased operating costs. Refer to the "Operations update" section at the beginning of this MD&A, where initiatives to reduce these costs are discussed.

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 (i)	400 bbls/d	Jan 2014 to Dec 2014	$98.00
NYMEX (i)	500 bbls/d	Jan 2014 to Dec 2014	$91.15
NYMEX (i)	400 bbls/d	Jan 2014 to Dec 2014	$91.15
NYMEX (ii)	250 bbls/d	Jan 2014 to Dec 2014	$90.00 - $94.95
NYMEX (ii)	100 bbls/d	Jan 2014 to Dec 2014	$93.00 - $95.35
NYMEX (i)	190 bbls/d	Jan 2015 to Dec 2015	$85.40
NYMEX (ii)	1,000 bbls/d	Jan 2015 to Jun 2015	$90.10 - $92.00
NYMEX (i)	400 bbls/d	Jul 2015 to Dec 2015	$87.90

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

Foreign Exchange:

Foreign Exchange Type	Contract Term	Price $US
Collar	Apr 2014	$1.05 - $1.09
Collar	May 2014	$1.05 - $1.09
Collar	Jun 2014	$1.05 - $1.09
Collar	Jul 2014	$1.05 - $1.09
Collar	Jul 2014	$1.05 - $1.09
Collar	Aug 2014	$1.05 - $1.09
Collar	Sep 2014	$1.05 - $1.09
Collar	Oct 2014	$1.05 - $1.09
Collar	Nov 2014	$1.05 - $1.09
Collar	Dec 2014	$1.05 - $1.09

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013	%
Realized gain (loss) - Commodity	(818)	24	-
Unrealized gain (loss) - Commodity	(1,114)	(1,812)	39
Net gain (loss) - Commodity	**$ (1,932)**	$ (1,788)	(8)
Realized gain (loss) - Foreign exchange	(24)	-	-
Unrealized gain (loss) - Foreign exchange	(194)	-	-
Net gain (loss) - Foreign exchange	**(218)**	-	-
Total net gain (loss)	**$ (2,150)**	$ (1,788)	(202)

On a year-over-year basis, the net value of the commodity price contracts has decreased. 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. On a quarter-over-quarter basis, a strengthening forward commodity pricing environment has caused the future value of these contracts to decrease, thus increasing the liability position at March 31, 2014.

On January 7, 2014, the Trust entered into a foreign exchange contract to mitigate the effects of foreign exchange rate ($CA/$US) fluctuations on monthly distribution payments. The foreign exchange contract reduced the benefit of the weakening Canadian dollar on the cost of the distributions and thus created a liability position on the balance sheet at March 31, 2014.

Finance expense

		Three Months Ended March 31, 2014		Three Months Ended March 31, 2013	%
Finance expense		877		515	70
Per boe	$	3.24	$	1.95	66

For the three months ended March 31, 2014, finance expense increased over the prior year's comparative quarter due to additional borrowing to acquire the remaining interest in the Permian properties, the initial acquisition of the Hardeman properties and the tuck-in acquisition of additional Hardeman properties.

As of March 31, 2014, the effective interest rate on bank debt for the period was 3.7% compared to 4.6% for the comparable period in 2013. During the quarter, the Trust utilized advances using the LIBOR rate option, which was lower than the base rate option on its borrowings.

Administrative expenses

		Three Months Ended March 31, 2014		Three Months Ended March 31, 2013	%
Administrative expenses		2,555		1,421	80
Per boe	$	9.43	$	5.39	75

Total administrative expenses for the first quarter were $2.6 million, representing approximately 25% of full year 2014 expected levels. Over the past year, engineering, geological, and business development staff were added to assist with full cycle property development, acceleration of the strategic focus on potential acquisitions and management of planned activities. Staff and related employment costs accounted for 68% of administrative expenses and 22% was related to professional service costs, audit, legal and tax fees.

Unit-based compensation

		Three Months Ended March 31, 2014		Three Months Ended March 31, 2013	%
Unit-based compensation expense (recovery)	$	(1,874)	$	(1,208)	55

A $1.9 million recovery of non-cash unit-based compensation expense was recorded during the first quarter of 2014 ($1.2 million recovery for the three months ended March 31, 2013). This was due to the change in fair market valuation as a result of: (i) a lower unit price at the end of the first quarter 2014 when compared to the unit price at year-end 2013 and, (ii) a reduction in the expected unit price volatility as the first quarter 2014 calculation incorporated the trading history of the Trust's units from November 24, 2010 to March 31, 2014 rather than incorporating the trading history of a representative sample of peer group entities as in prior periods.

The dollar amount of unit-based compensation recovery or expense 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 (i) the actual year-over-year price appreciation of the trust units (for holders of restricted unit rights and unit rights), or (ii) the actual price of the units relative to the exercise price of the options at the time the options are exercised (for holders of options and which would not result in a cash outlay for the Trust).

The Trust is, however, required to re-determine the fair value of the liability each quarter relating to: (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. The decrease in the liability and associated recovery from December 31, 2013 to March 31, 2014 was primarily due to the reduction of expected unit price volatility calculation required for the Black-Scholes valuation which more than offset new options issued during the period.

During the first quarter, $0.2 million (three months ended March 31, 2013 - $0.1 million) was paid out in cash for amounts related to vested restricted unit rights and U.S. based unit rights. The liability that was, and continues to be, accrued from inception for these cash settled awards was reduced by such cash payments.

Tax horizon

The tax horizon, as determined from a full cycle corporate model incorporating cash flows from the year end reserves evaluation report plus all applicable U.S. deductions, indicates that no material U.S. taxes are expected to be payable in respect of income attributable to the Luling and Midland areas for several years. Management expects to extend this period through continued capital investments and additional acquisitions in the U.S. as the Trust executes its business plan. No taxes are expected to be payable by the Trust in Canada because the Trust will distribute its full taxable income each year to unitholders and will not be a SIFT trust, as defined under the *Income Tax Act* (Canada), provided that the Trust complies at all times with the investment restrictions as set forth in the Trust Indenture.

Summary of quarterly results

	Q1/2014	Q4/2013	Q3/2013	Q2/2013	Q1/2013	Q4/2012	Q3/2012	Q2/2012
($000's except for boe/d and per unit amounts)								
Sales volumes – boe/d	3,010	2,994	3,052	3,022	2,928	2,986	2,825	2,400
Revenue, net of royalties	19,457	17,733	19,517	17,162	16,805	16,519	15,181	13,077
per boe	71.82	64.37	69.51	62.42	63.77	60.13	58.41	59.90
Funds flow from operations	10,341	8,794	11,615	11,977	11,884	9,905	9,039	7,233
per boe	38.18	31.93	41.37	43.56	45.10	36.06	34.78	33.13
per unit – basic	0.32	0.28	0.37	0.39	0.40	0.34	0.32	0.31
per unit – diluted	0.25	0.28	0.37	0.39	0.40	0.32	0.32	0.31
Income (loss)	2,218	156	(3,241)	3,919	4,080	(403)	(1,095)	8,567
per unit – basic	0.07	0.00	(0.10)	0.13	0.14	(0.02)	(0.04)	0.37
per unit - diluted	0.02	0.00	(0.10)	0.13	0.14	(0.02)	(0.04)	0.33
Cash distributions declared	8,555	8,376	8,204	8,026	7,828	7,653	7,512	6,628
per issued unit	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625
Current assets	9,116	9,889	9,950	11,443	9,913	14,464	14,209	18,758
Current liabilities	33,348	30,461	20,942	19,874	11,982	17,512	23,723	28,158
Total assets	356,332	335,679	306,021	311,271	283,112	284,802	283,913	291,273
Total non-current liabilities	79,684	70,521	55,069	50,654	39,873	42,111	35,136	27,192
Unitholders' equity	243,300	234,697	230,010	240,743	231,257	225,179	225,055	235,923
Units outstanding for accounting purposes	32,836	32,149	31,469	30,707(1)	29,960(1)	29,269(1)	28,654(1)	27,895(1)
Units issued	32,836	32,149	31,469	30,813	30,066	29,375	28,783	28,283

Note:

(1) Units outstanding for accounting purposes exclude those units issued 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".

With the exception of the fourth quarter 2013, which encountered non-recurring weather related delays and non-owned infrastructure problems, production has generally increased commensurate with well tie-ins and acquisitions. First quarter 2014 sales volumes were essentially level with the previous quarter since the planned recompletion program in the Permian properties necessitated temporarily shutting in the wells that were being recompleted. Subsequently, these wells will resume production from additional zones.

Funds flow from operations increased in the first quarter of 2014, when compared to the prior quarter primarily due to higher commodity prices. Generally, in times of steady or increasing prices, funds flow from operations grows as sales volumes increase, and on a per-boe basis, will decline when volumes decline. 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.

Income (loss) on a quarterly basis often does not move directionally or by the same amount as movements in funds flow from operations. This is primarily due to items of a non-cash nature that factor into the calculation of income (loss), and those that are required to be fair valued at each quarter end. By way of example, first quarter 2014 funds flow from operations increased 18% from the fourth quarter 2013 while first quarter income increased by 1,322%. This occurred due to a lower unit price at the end of the first quarter of 2014, which caused a unit-based compensation recovery to be recorded upon performing a fair market valuation of future unit-based payments.

Liquidity and capital resources

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

Management's objective is to maintain an external debt to cash flow ratio not to exceed 1.5 to 1.0. This ratio may increase at certain times as a result of acquisitions or phasing of the capital program. As at March 31, 2014, the Trust's ratio of ending debt to trailing cash flow on an annualized basis was approximately 2.1 to 1.0 but includes both Hardeman property acquisitions from late November 2013 for $27.1 million and February 2014 for $5.3 million, as well as 55% of the 2014 capital program. (Refer to the "Operations update" section at the beginning of this MD&A.) Full year 2014 guidance is in the range of 1.5 to 1.0.

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

Funds flow from operations

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

	Three Months Ended March 31, 2014		Three Months Ended March 31, 2013	
($000's)	**$**	**$ /boe**	$	$ /boe
Field netback	14,705	54.29	13,857	52.59
Cash settled award payments	(166)	(0.61)	(114)	(0.43)
Administrative expenses	(2,555)	(9.43)	(1,421)	(5.39)
Realized risk management gain (loss)	(842)	(3.11)	24	0.09
Finance expense	(758)	(2.80)	(450)	(1.71)
Realized foreign exchange loss (1)	(43)	(0.16)	(12)	(0.05)
Funds flow from operations	**$ 10,341**	**$ 38.18**	$ 11,884	$ 45.10

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 (revolving and non-revolving)

As of March 31, 2014, the Trust had approximately $US 11.4 million of unused credit on its $US 80 million revolving credit facility and was fully drawn on its $US 10 million non-revolving term credit facility, both of which are held with a syndicate of Canadian chartered banks.

The Trust plans to pay off the non-revolving term credit facility through cash flow, but other options are available which include increasing the revolving component of the credit facility by the amount of the expiring term facility through additions to proved developed producing reserves, or paying off the non-revolving term credit facility with proceeds from subordinated debt or equity financings, if available on favourable terms.

Working capital

At March 31, 2014, the Trust had a working capital deficiency, excluding the non-revolving term credit facility, non-cash unit-based payments and non-cash risk management liability, of approximately $3.0 million. The Trust has, in total, a $99.5 million ($US 90 million) credit facility of which, $12.6 million ($US 11.4 million) was available at March 31, 2014.

Unitholders' equity

All Trust capital issuances during the first quarter were issued pursuant to the distribution reinvestment plans as detailed below.

As a result of its Premium Distribution™ and Distribution Reinvestment Plan, the Trust received proceeds resulting from the issuance of units from treasury to those unitholders who have opted to participate in the plan. A summary of the number of units issued, proceeds resulting from the issuance of units and average price per unit resulting from the plan at March 31, 2014, December 31, 2013 and March 31, 2013 were as follows:

(000's)		**Three Months Ended March 31, 2014**		Year Ended December 31, 2013	Three Months Ended March 31, 2013
Number of units issued		687,356		2,879,766	690,988
Net Proceeds from issuance of Trust Capital	$	5,241	$	20,173	4,878
Average price per unit	$	7.63	$	7.30	7.06

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. Cash distributions paid in the first quarter (for the December 2013, and January and February 2014 record dates) totaled approximately $8.5 million.

At March 31, 2014, the Trust had issued 32,836,265 units (December 31, 2013 - 32,148,909; March 31, 2013 - 30,065,548). As at the date of this MD&A, 33,115,926 units are issued and 3,176,750 options are outstanding.

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

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
(000's)	**$**	$
Income for the period	2,218	4,080
Cash distributions paid	(8,495)	(7,767)
Shortfall of income over cash distributions paid	**(6,277)**	(3,687)
Funds flow from operations[1]	10,341	11,884
Changes in working capital	2,736	(3,373)
Abandonment expenditures	-	(8)
Net cash provided by operating activities	13,077	8,503
Cash distributions paid	(8,495)	(7,767)
Excess of net cash provided by operating activities over cash distributions paid	**4,582**	736

Note:

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

For the three months ended March 31, 2014 and 2013, cash distributions paid exceeded income for the period due to non-cash items which are deducted or added in determining income for the period. Income 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 income (loss), and are required to be fair valued at each period end. Examples of non-cash items include depreciation, depletion and amortization, unit-based compensation, and unrealized risk management losses, all of which have no impact on cash available to pay distributions.

For the three months ended March 31, 2014 and 2013, net cash provided by operating activities exceeded cash distributions paid by $4.6 million and $0.7 million respectively.

Capital expenditures

Capital expenditures during the three months ended March 31, 2014 and March 31, 2013 were as follows:

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
(000's)	**$**	$
Exploration and evaluation[1]	16	19
Acquisition in Hardeman County	5,310	-
Intangible drilling and completions	9,018	3,921
Seismic	2,200	-
Well equipment and facilities	283	179
Other	11	50
	$ 16,838	$ 4,169

Notes:

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

During the first quarter of 2014, the Trust spent $9.0 million on drilling and completions and recompletions. Of this total, $1.8 million was spent drilling two wells on the Salt Flat properties and $1.4 million was spent on significant drilling preparation work on two wells on the Permian properties, which were rig-released in April. Additionally, $5.8 million was spent to recomplete existing wells primarily on the Permian properties. $2.2 million was spent on seismic on the Hardeman and Salt Flat properties.

Acquisitions

On February 27, 2014, the U.S. subsidiary of the Trust acquired additional undeveloped acreage and an average 66% working interest in producing properties in Hardeman County, Texas and Greer, Harmon and Jackson Counties, Oklahoma for cash consideration of $5.3 million ($US 4.7 million), which includes preliminary closing adjustments of $0.3 million. The acquisition had an effective date of December 1, 2013 and increases Eagle's recently established position in Hardeman County.

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

Identifiable assets acquired and liabilities assumed ($CA):

Oil and gas properties	$ 5,398
Decommissioning liabilities	(88)
	$ 5,310

Activity summary

Wells drilled (rig-released)	**Three Months Ended March 31, 2014**		Three Months Ended March 31, 2013	
	Gross	**Net**	Gross	Net
Salt Flat	2	1.6	-	-
Permian	-	-	-	-
Hardeman	-	-	-	-
Total	**2**	**1.6**	-	-

Wells brought on-stream	Three Months Ended March 31, 2014		Three Months Ended March 31, 2013	
	Gross	**Net**	Gross	Net
Salt Flat	2	1.6	-	-
Permian	-	-	1	1
Hardeman	-	-	-	-
Total	**2**	**1.6**	1	1

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

Commitments

The Trust has committed to future payments as follows:

(000's)		**Total**		**Less than 1 year**		**1 – 3 years**		**After 3 years**
Operating leases (1)(2)		2,847		568		1,545		734
Total contractual obligations	**$**	**2,847**	**$**	**568**	**$**	**1,545**	**$**	**734**

Notes:

(1) Calgary, Alberta office lease: On January 1, 2013, the Trust entered into a head-lease agreement for office space 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 of $0.3 million, with 46 months and approximately $1.8 million remaining at March 31, 2014.

(2) Houston, Texas office lease: The agreement was entered into on April 1, 2011, and had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease agreement 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 111,293 and approximate $US 1.5 million with 45 months and approximately $US 1.3 million remaining at March 31, 2014. In $CA, the remaining future minimum lease payments approximate $1.4 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.11.

Non-IFRS financial measures

Statements throughout this MD&A make reference to the terms "field netback" and "funds flow from operations" which are non-IFRS financial measures that do not have a standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that "field netback" and "funds flow from operations" 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. Field netback is calculated by subtracting royalties and operating costs from revenues. Other financial data has been prepared in accordance with IFRS. 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, 2014		Three Months Ended March 31, 2013
Earnings (Loss)	**$**	**2,218**	$	4,080
Add back (deduct) items not involving cash:				
Unit-based compensation – non-cash portion		(2,040)		(1,322)
Unrealized risk management loss		1,308		1,812
Depreciation, depletion and amortization		8,736		7,249
Finance expense		119		65
Funds flow from operations	**$**	**10,341**	$	11,884
Add back (deduct) items not directly related to field operations:				
Realized foreign exchange loss (gain)		43		12
Finance expense (cash portion)		758		450
Risk management (gain) loss-realized		842		(24)
Administrative expenses		2,555		1,421
Cash settled award payments		166		114
Field netback	**$**	**14,705**	$	13,857

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

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

Critical accounting estimates

There have been no changes to the Trust's critical accounting estimates and judgments in the first quarter of 2014. 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, 2013.

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, 2014 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 2014 capital budget and specific uses, including the timing and expected results of the 2014 drilling program;
- the Trust's expectation regarding its 2014 full year average working interest production, operating costs and field netbacks;
- the Trust's expectation regarding its 2014 funds flow from operations and sensitivities of funds flow from operations to production rates and commodity prices;
- the Trust's expectation regarding its 2014 payout ratios and debt to trailing cashflow;
- the Trust's expectations regarding the percentage to be drawn on its credit facility;
- the sensitivities of 2014 payout ratios to changes in production rates and commodity prices;
- projected debt to cash flow, and management's objective to maintain a debt to cash flow ratio below 1.5 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;
- 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 2014 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;
- projected operating costs, which are based on historical information and anticipated increases in the cost of equipment and services;
- the level of unitholder participation in Eagle's Premium DRIP™ and distribution reinvestment programs; and
- the regulatory framework governing taxes in the U.S. and Canada and the Trust's status as a "mutual fund trust" and not a "SIFT trust".

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 2014 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, drilling program, 2014 capital budget, funds flow from operations, Eagle's Premium DRIP™ and distribution reinvestment programs 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, 2014 and March 31, 2013

Eagle Energy Trust

Condensed Consolidated Balance Sheets

(Thousands of Canadian dollars) (unaudited)

	Note		**March 31, 2014**		December 31, 2013
ASSETS					
Current assets					
Cash		$	-	$	1,435
Trade and other receivables			8,538		7,826
Prepaid expenses			578		628
			9,116		**9,889**
Non-current assets					
Exploration and evaluation			544		508
Oil and gas properties	10		345,697		324,349
Property, plant and equipment	11		301		327
Other intangible assets			674		606
			347,216		**325,790**
Total Assets		**$**	**356,332**	**$**	**335,679**
LIABILITIES					
Current liabilities					
Trade and other payables		$	9,196	$	5,929
Distributions payable	12		2,873		2,813
Unit-based payments	6		7,589		9,630
Risk management liability	3		2,635		1,453
Current debt	13		11,055		10,636
			33,348		**30,461**
Non-current liabilities					
Risk management liability	3		185		-
Long-term debt	13		75,837		67,485
Deferred income tax			-		-
Decommissioning liability	14		3,662		3,036
			79,684		70,521
Total Liabilities		**$**	**113,032**	**$**	**100,982**
UNITHOLDERS' EQUITY					
Trust capital	15	$	302,643	$	297,447
Currency reserves			20,844		11,100
Accumulated earnings (loss)			8,822		6,604
Accumulated cash distributions			(89,009)		(80,454)
Total Unitholders' Equity		**$**	**243,300**	**$**	**234,697**
Total Liabilities and Unitholders' Equity		**$**	**356,332**	**$**	**335,679**

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

See Note 17 "Commitments".

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, 2014**		Three Months Ended March 31, 2013
Revenue		$	26,553	$	23,341
Royalties			(7,096)		(6,536)
			19,457		**16,805**
Operating expenses			4,072		2,383
Transportation expenses			680		565
Administrative expenses			2,555		1,421
Depreciation, depletion and amortization			8,736		7,249
Operating profit			**3,414**		**5,187**
Unit based compensation (recovery)	6		(1,874)		(1,208)
Finance expense	7		877		515
Risk management loss	3		2,150		1,788
Foreign exchange loss net			43		12
Earnings before taxes			**2,218**		**4,080**
Income tax expense (recovery)	8		-		-
Earnings		**$**	**2,218**	**$**	**4,080**
Other comprehensive income					
Items that may be reclassified subsequently to earnings					
Foreign currency translation gain			9,744		4,948
Comprehensive income		**$**	**11,962**	**$**	**9,028**
Earnings per unit					
Basic	**9**	**$**	**0.07**	**$**	**0.14**
Diluted	**9**	**$**	**0.02**	**$**	**0.14**

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

	Note	Number of trust units	Trust capital	Currency reserve	Accumulated earnings/ loss	Accumulated cash distributions	Deficit	Total Unitholders' equity
Balance at December 31, 2012		**29,269**	**276,526**	**(5,017)**	**1,690**	**(48,020)**	**(46,330)**	**$ 225,179**
Earnings	9	-	-	-	4,080	-	4,080	4,080
Foreign currency translation loss		-	-	4,948	-	-	-	4,948
Total comprehensive income		-	-	4,948	4,080	-	4,080	9,028
Issuance of trust capital		691	4,878	-	-	-	-	4,878
Trust unit issuance costs		-	-	-	-	-	-	-
Unitholder distributions		-	-	-	-	(7,828)	(7,828)	(7,828)
		691	4,878	-	-	(7,828)	(7,828)	(2,950)
Balance at March 31, 2013		**29,960**	**281,404**	**(69)**	**5,770**	**(55,848)**	**(50,078)**	**$ 231,257**
Balance at December 31, 2013		**32,149**	**297,447**	**11,100**	**6,604**	**(80,454)**	**(73,850)**	**$ 234,697**
Earnings	9	-	-	-	2,218	-	2,218	2,218
Foreign currency translation loss		-	-	9,744	-	-	-	9,744
Total comprehensive income		-	-	9,744	2,218	-	2,218	11,962
Issuance of trust capital	15	687	5,241	-	-	-	-	5,241
Trust unit issuance costs	15	-	(45)	-	-	-	-	(45)
Unitholder distributions	12	-	-	-	-	(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**

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, 2014 and March 31, 2013
(Thousands of Canadian dollars) (unaudited)

	Note		**Three Months Ended March 31, 2014**		Three Months Ended March 31, 2013
Cashflows from operating activities					
Earnings		**$**	2,218	$	4,080
Adjustments for non-cash items:					
Depreciation, depletion and amortization			8,736		7,249
Unit-based compensation – non-cash portion			(2,040)		(1,322)
Unrealized risk management loss			1,308		1,812
Finance expense			119		65
			10,341		11,884
Changes in working capital:					
Trade and other receivables			(411)		1,006
Prepaid expenses			72		21
Trade and other payables			712		(4,461)
			373		(3,434)
Cash generated from operations		$	10,714	$	8,511
Abandonment expenditures			-		(8)
Income taxes paid			-		-
Net cash generated by operating activities		**$**	**10,714**	$	**8,442**
Cash flows from investing activities					
Additions to exploration and evaluation			(16)		(19)
Additions to oil and gas properties			(11,500)		(4,100)
Additions to property, plant and equipment			(12)		(50)
Acquisition of oil and gas assets	4		(5,310)		-
Change in non-cash working capital			2,363		
Net cash used in investing activities		**$**	**(14,475)**	**$**	**(4,169)**
Cash flows from financing activities					
Debt			5,634		(3,168)
Proceeds from issuance of units			5,241		4,878
Trust unit issue costs			(45)		-
Cash distributions to unitholders			(8,495)		(7,767)
Change in non-cash working capital			-		60
Deferred financing charges			(145)		-
Net cash generated by (used in) financing activities		**$**	**2,190**	**$**	**(5,997)**
Net increase (decrease) in cash and cash equivalents			**(1,571)**		**(1,724)**
Effects of exchange rates on cash and cash equivalents			136		48
Cash at beginning of the period			1,435		4,007
Cash at end of the period		**$**	**-**	**$**	**2,331**

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, 2014 and March 31, 2013
(in Canadian dollars)

1. Reporting entity / Structure of the Trust

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. Eagle Energy Trust's subsidiaries are in the business of acquiring, developing and producing petroleum reserves in the United States. 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.

Throughout these notes to the condensed consolidated interim 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 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 an indirectly owned subsidiary of the Trust.

Operations officially commenced on November 24, 2010, concurrent with the closing of its first acquisition.

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

2.1. Basis of preparation

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 8, 2014.

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, 2013, 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, 2013, 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.

There were no new or amended standards issued during the three months ended March 31, 2014 that are applicable to the Trust in future periods. 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, 2013. 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, 2013.

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, 2014, 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, 2014

Commodity Contracts

As at March 31, 2014, 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 net present value $000's $CA*	*Non-current net present value $000's $CA*
Oil Fixed Price								
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	98.00	98.00	(31)	-
NYMEX (i)	500	bbls/d	Jan-14	Dec-14	91.15	91.15	1,000	-
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	91.15	91.15	801	-
NYMEX (ii)	250	bbls/d	Jan-14	Dec-14	90.00	94.95	307	-
NYMEX (ii)	100	bbls/d	Jan-14	Dec-14	93.00	95.35	93	-
NYMEX (i)	190	bbls/d	Jan-15	Dec-15	85.40	85.40	(481)	(617)
NYMEX (ii)	1,000	bbls/d	Jan-15	Jun-15	90.10	92.00	752	777
NYMEX (i)	400	bbls/d	Jul-15	Dec-15	87.90	87.90	-	25
Commodity - unrealized risk management position							2,441	185

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

Foreign Exchange Contracts

As at March 31, 2014, the Trust has entered in the following contract to mitigate the effects of fluctuating foreign exchange rates:

Foreign Exchange	*Quantity ($CA)*	*Term*	*Floor $US*	*Ceiling $US*	*Current net present value $000's $CA*	*Non-current net present value $000's $CA*
Collar	906	Apr-14	1.05	1.09	13	-
Collar	913	May-14	1.05	1.09	17	-
Collar	918	Jun-14	1.05	1.09	19	-
Collar	924	Jul-14	1.05	1.09	21	-
Collar	931	Aug-14	1.05	1.09	22	-
Collar	937	Sep-14	1.05	1.09	24	-
Collar	943	Oct-14	1.05	1.09	25	-
Collar	950	Nov-14	1.05	1.09	26	-
Collar	956	Dec-14	1.05	1.09	27	-
Foreign exchange - unrealized risk management position					194	-

Total Unrealized Risk Management Positions:

		Current net present value $000's $CA	**Non-current net present value $000's $CA**
Commodity		(2,441)	(185)
Foreign exchange		(194)	-
Total unrealized risk management position	$	**(2,635)**	**(185)**

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

	March 31, 2014			March 31, 2013		
$000's	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)
Net effect - commodity	818	1,114	1,932	(24)	1,812	1,788
Net effect - foreign exchange	24	194	218	-	-	-
Net effect - risk management	**$ 842**	**1,308**	**2,150**	$ (24)	$ 1,812	$ 1,788

Determination of fair values

The net fair value of Eagle's unrealized risk management positions at March 31, 2014 is a liability of $2,626,370 (December 31, 2013 - $1,453,286 liability) for commodity contracts and a liability of $194,206 (December 31, 2013 - $nil) for foreign exchange contracts. The net fair value of Eagle's unrealized risk management positions have 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 current debt 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. Acquisitions

On February 27, 2014, the U.S. subsidiary of the Trust acquired undeveloped acreage and an average 66% working interest in producing properties in Hardeman County, Texas and in Greer, Harmon and Jackson counties, Oklahoma for cash consideration of $5,310,317, which includes preliminary closing adjustments of $303,335. The acquisition had an effective date of December 1, 2013 and increases Eagle's recently established position in Hardeman County.

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

Identifiable assets acquired and liabilities assumed ($CAD):	
Oil and gas properties	$ 5,398
Decommissioning liabilities	(88)
	$ 5,310

5. Operating segments

The operations of the Trust comprise one operating segment: oil and gas exploration, development and the sale of hydrocarbons and related activities. All of the Trust's assets and liabilities, income and expenses relate to this segment and the relevant disclosures have been made elsewhere in these financial statements.

Geographical information

The Trust's operational activities are wholly focused in the continental United States and are supported by offices in Houston, Luling, and Midland, Texas. The Trust's head office is in Calgary, Alberta. All inter-segment and geographical transactions have been eliminated in consolidation.

Revenue

All of the Trust's revenue from external customers is derived from its operations in the United States.

Non-Current Assets

Substantially all of the Trust's non-current assets are within the United States.

6. Unit-based payments

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

$ 000's	Note	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
Units issued on performance option surrender	5(a)	-	(29)
Restricted unit rights	5(b)	(379)	(119)
Unit options	5(c)	(1,425)	(994)
Unit rights	5(d)	(70)	(66)
Total unit-based compensation expense (recovery)		**$ (1,874)**	$ (1,208)

The following table reconciles the unit-based payments liability.

$ 000's	Note	March 31, 2014	December 31, 2013
Units issued on performance option surrender	5(a)	-	-
Restricted unit rights	5(b)	695	1,240
Unit options	5(c)	5,573	6,998
Unit rights	5(d)	1,321	1,392
Total unit-based payments liability		**$ 7,589**	$ 9,630

Note (a)

Units issued upon surrender of performance options

At March 31, 2014, no escrowed units were outstanding. The following schedule shows the continuity of escrowed units issued upon surrender of performance options:

	Three Months Ended March 31, 2014	Year Ended December 31, 2013	Three Months Ended March 31, 2013
Balance, beginning of period	-	105,417	105,417
Issued	-	-	-
Transferred to the Trust capital account	-	(105,417)	-
Balance, end of period, in escrow	**-**	-	105,417

Note (b)

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

For the three months ended March 31, 2014, $166,037 has been paid to the RUR holders (year ended December 31, 2013 - $1,110,734, three months ended March 31, 2013 – $110,655).

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

	Three Months Ended March 31, 2014	Year Ended December 31, 2013	Three Months Ended March 31, 2013
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	421,667

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

	March 31, 2014	December 31, 2013	March 31, 2013
Fair value at the balance sheet date	$ 5.09	$ 5.72	$ 3.85
Volatility	27%	32%	32%
Life of RURs	6.8 years	7.0 years	7.8 years
Risk-free interest rate	2.46%	2.70%	1.91%

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

Note (c)

Unit option plan

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

	Three Months Ended March 31, 2014		Year Ended December 31, 2013		Three Months Ended March 31, 2013	
	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	3,126,750	$ 7.05	2,214,668	$ 8.23	2,214,668	$ 8.23
Forfeited	-	-	(249,918)	7.69	(235,418)	5.47
Exercised	-	-	-	-	-	-
Granted	50,000	8.31	1,162,000	6.72	-	-
Outstanding at end of period	**3,176,750**	**$ 6.81**	3,126,750	$ 7.05	1,979,250	$ 8.01
Exercisable at end of period	**1,425,176**	**$ 6.75**	1,411,010	$ 7.00	770,755	$ 7.61

The range of exercise prices of the outstanding options is as follows at March 31, 2013:

	Weighted average exercise price	Weighted average contractual life (years)
$5.66 - $8.31	**$ 6.81**	**8.1**

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

	March 31, 2014	December 31, 2013	March 31, 2013
Fair value - at balance sheet date	$ 2.69	$ 3.76	$ 2.25
Unit trading price - closing	$ 7.13	$ 8.07	$ 6.60
Exercise price – weighted average	$ 6.81	$ 7.05	$ 8.01
Volatility	27%	32%	32%
Option life – weighted average	8.1 years	8.4 years	8.4 years
Distributions – none estimated, due to declining strike price feature	0%	0%	0%
Risk-free interest rate	2.46%	2.70%	1.91%

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 from November 24, 2010 to March 31, 2014. Prior to March 31, 2014 a representative sample of peer group entities was used in order to determine expected unit price volatility.

Note (d)

Unit Rights (URs) plan

For the three months ended March 31, 2014, $nil has been paid to the UR holders (year ended December 31, 2013 - $78,668, three months ended March 31, 2013 - $3,590).

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

	Three Months Ended March 31, 2014	Year Ended December 31, 2013	Three Months Ended March 31, 2013
Balance, beginning of period	997,000	493,000	493,000
Issued	-	649,000	-
Forfeited	-	(145,000)	(40,000)
Balance, end of period	997,000	997,000	453,000
Number of unit rights vested	**169,336**	152,670	68,337

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, 2014	December 31, 2013	March 31, 2013
Fair value at the balance sheet date	$ 3.57	$ 3.62	$ 1.92
Volatility	27%	32%	32%
Life of restricted URs	8.9 years	9.2 years	9.0 years
Risk-free interest rate	2.46%	2.70%	1.91%

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 from November 24, 2010 to March 31, 2014. Prior to March 31, 2014 a representative sample of peer group entities was used in order to determine expected unit price volatility.

7. Finance expense

$ 000's	**Three Months Ended March 31, 2014**	Three Months Ended March 31, 2013
Interest expense on debt	$ 753	$ 439
Amortization of deferred financing costs	96	55
Standby and bank fees	5	11
Accretion of decommissioning provision	23	10
Finance expense	**$ 877**	$ 515

8. Taxation

Reconciliation of effective tax rate

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

$ 000's		**Three Months Ended March 31, 2014**		Three Months Ended March 31, 2013
Earnings (loss) before taxation		$ 2,218		$ 4,080
Expected tax rate		35%		35%
Expected income tax provision (recovery)		776		1,428
Decrease (Increase) resulting from:				
Non-deductible items – permanent differences				
Administrative expenses of the Trust	35%	322	35%	195
Unit-based compensation	35%	(656)	35%	(423)
Foreign exchange gain, net	35%	(214)	35%	-
Risk management loss	35%	-	35%	-
Changes in temporary differences for which no amounts are recognized	35%	1,133	35%	213
Items deductible at the subsidiary level				
Interest on internal debt of subsidiary	35%	(1,364)	35%	(1,363)
Other	35%	3	35%	(50)
Total income tax expense (recovery)	35%	**$ --**	35%	$ -

Deferred tax assets and liabilities:

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

$ 000's	**March 31, 2014**	December 31, 2013
Deferred tax liabilities		
Oil and gas properties in excess of tax value	$ 22,987	$ 21,440
Exploration and evaluation assets	-	-
	22,987	21,440
Less deferred tax assets:		
Non-capital losses – US based	(29,521)	(26,841)
Net deferred tax liability (asset) – before valuation allowance	(6,534)	(5,401)
Unrecognized deferred tax asset	6,534	5,401
Net deferred tax liability (asset)	**$ -**	$ -

9. Earnings per unit

$ 000's	**Three Months Ended March 31, 2014**	Three Months Ended March 31, 2013
Earnings attributable to unitholders - basic	$ 2,218	$ 4,080
Earnings attributable to unitholders - diluted	$ 793	$ 4,080
Weighted average number of units outstanding - basic	32,427	29,545
Weighted average number of units outstanding - diluted	35,266	29,545
Earnings per unit - basic	**$ 0.07**	$ 0.14
Earnings per unit - diluted	**$ 0.02**	$ 0.14

10. Oil and gas properties

$ 000's		Developed oil and gas assets		Production facilities and equipment		Capitalized future decom-missioning costs		Total
Cost								
At December 31, 2013	$	392,404	$	7,106	$	2,944	$	402,454
Additions		32,179		364		599		33,142
At March 31, 2014	**$**	**424,583**	**$**	**7,470**	**$**	**3,543**	**$**	**435,596**
Accumulated depreciation and impairment								
At December 31, 2013	$	(73,818)	$	(3,999)	$	(288)	$	(78,105)
Depreciation		(11,211)		(526)		(57)		(11,794)
At March 31, 2014	**$**	**(85,029)**	**$**	**(4,525)**	**$**	**(345)**	**$**	**(89,899)**
Net book value								
At December 31, 2013	$	318,586	$	3,107	$	2,656	$	324,349
Net change for the period		20,968		(162)		542		21,348
At March 31, 2014	**$**	**339,554**	**$**	**2,945**	**$**	**3,198**	**$**	**345,697**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $US 87,857,988 (December 31, 2013 - $US 101,436,200) were included in the depletion calculation.

11. Property, plant and equipment

$ 000's		Furniture, fixtures, and equipment		Computer equipment		Vehicles		Total
Cost								
At December 31, 2013	$	137	$	467	$	86	$	690
Additions		4		27		3		34
At March 31, 2014	**$**	**141**	**$**	**494**	**$**	**89**	**$**	**724**
Accumulated Depreciation								
At December 31, 2013	$	(41)	$	(289)	$	(33)	$	(363)
Depreciation		(11)		(45)		(4)		(60)
At March 31, 2014	**$**	**(52)**	**$**	**(334)**	**$**	**(37)**	**$**	**(423)**
Net book value								
At December 31, 2013	**$**	96	$	178	$	53	$	327
Net change		(7)		(18)		(1)		(26)
At March 31, 2014	**$**	**89**	**$**	**160**	**$**	**52**	**$**	**301**

12. Distributions payable

$ 000's		March 31, 2014		December 31, 2013
Beginning balance	$	2,813	$	2,570
Distributions declared		8,555		32,434
Less distributions paid		(8,495)		(32,191)
Outstanding distributions declared and payable	**$**	**2,873**	$	2,813

Distributions are declared and paid monthly. The outstanding balance at March 31, 2014 represents the distribution declared March 14, 2014 and paid April 23, 2014. The outstanding balance at December 31, 2013 represents the distributions declared December 16, 2013 and paid January 23, 2014.

13. Debt

Total interest paid on debt for the three months ended March 31, 2014 was $0.8 million at an average interest rate of 3.7%. At March 31, 2014, there were no changes to the terms of the Trust's debt agreements and there were no covenant violations.

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

$000's		$US		$CA
Non-revolving	$	10,000	$	11,055
Revolving		80,000		88,440
Total authorized		90,000		99,495
Less: Current debt		10,000		11,055
Long-term debt		68,600		75,837
Available	**$**	**11,400**	**$**	**12,603**

The exchange rate in effect at March 31, 2014 was $US 1 equal to $CA 1.11.

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

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

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

14. Decommissioning liability

$000's		Three Months Ended March 31, 2014		Year Ended December 31, 2013
Beginning Balance	$	3,036	$	1,744
Acquisition		88		672
Additions		180		191
Changes in estimates		215		315
Abandonment expenditures		-		(9)
Accretion (unwinding of discount)		23		61
Effects of foreign exchange rate		120		62
Ending Balance	**$**	**3,662**	$	3,036

The decommissioning provision reflects the present value of internal estimates of future decommissioning costs of the Trust's net ownership position in oil and gas wells and related facilities at the relevant balance sheet date determined using local pricing conditions and requirements. These costs are expected to be incurred between 2017 and 2063. 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 inflation at an assumed 2% per-annum inflation rate), and discounted using a risk-free discount rate of 2% at March 31, 2014 (March 31, 2013 – 3%) for the Salt Flat properties, 3% for the Permian properties (March 31, 2013 - 3%), and 3% for the Hardeman properties (March 31, 2013 - N/A).

15. Trust capital

Trust units outstanding

	Three Months Ended March 31, 2014			Year Ended December 31, 2013		
$000's	**Number of units**		**Amount**	Number of units		Amount
Beginning balance	32,149	$	297,447	29,269	$	276,526
Issuance of Trust capital pursuant to DRIP	687		5,241	2,775		20,173
Units released from escrow	-		-	105		859
Trust Unit issuance costs	-		(45)	-		(111)
Ending balance	**32,836**	**$**	**302,643**	32,149	$	297,447

For the three months ended March 31, 2014, the Trust incurred $45,070 (December 31, 2013 - $111,434) of unit issuance costs.

16. Related party disclosures

The Trust has no party holding voting control.

Key management

Key management personnel includes the Trust's Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, Vice-President Business Development, Vice-President Finance, General Counsel/Corporate Secretary and the Directors.

Intercompany transactions

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

17. Commitments

Head office lease in Calgary, Alberta

On January 1, 2013, the Trust entered into a head-lease agreement for office space 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 of $0.3 million, with 46 months and approximately $1.8 million remaining at March 31, 2014.

Operating lease commitment – office lease in Houston, Texas

The agreement was entered into on April 1, 2011, and originally had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease agreement 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 111,293 and approximate $US 1.5 million, with 45 months and approximately $US 1.3 million remaining at March 31, 2014. In $CA the remaining future minimum lease payments approximate $1.4 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.11.

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

Robert J. Cunningham
Vice President, Business Development

James D. Elliott
Vice President, Finance

Jo-Anne M. Bund
General Counsel/Corporate Secretary

Auditors

PricewaterhouseCoopers LLC

Trustee and Transfer Agent

Computershare Trust Company of Canada

Engineering Consultants

Netherland Sewell and Associates, Inc.

Bankers

Bank of Nova Scotia

Legal Counsel

Bennett Jones LLP

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