EAGLE ENERGY™ TRUST

Management's Discussion and Analysis

November 6, 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 November 6, 2014, should be read in conjunction with the Trust's unaudited interim condensed consolidated financial statements and accompanying notes for the three and nine months ended September 30, 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 under the Trust's issuer profile on SEDAR at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

The 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 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.

The foreign exchange rate as at September 30, 2014 was $US 1 equal to $CA 1.12 (September 30, 2013 - $US 1 equal to $CA 1.03), and the average foreign exchange rate for the nine months ended September 30, 2014 was $US 1 equal to $CA 1.09 (for the nine months ended September 30, 2013 - $US equal to $CA 1.02).

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 strategy of the Trust has been to invest in operating subsidiaries that will acquire on-shore petroleum reserves and production in certain regions of the United States. The Trust has submitted for approval by its unitholders, at a Special Meeting a resolution to amend the constating document of the Trust to permit it to acquire petroleum reserves and production in Canada as well as in the United States. This is not a change from the strategy to the Trust to invest in the United States; rather it is intended only to augment the ability of management to maximize value for the unitholders of the Trust. Eagle's objective is to provide investors with a reliable distribution paying investment by generating stable cash flows and managing risk while delivering moderate growth through increasing unit value.

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 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, increasing the total interest to 100%. On November 25, 2013, the Trust acquired an approximate 90% working interest in certain producing properties in Hardeman county, Texas and subsequently acquired an additional 66% working interest in certain producing properties in Hardeman county, Texas and Greer, Harmon and Jackson counties, Oklahoma on February 27, 2014.

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

On August 29, 2014, the Trust disposed of its entire working interest in its Permian properties and used the net proceeds to fully retire its outstanding debt, as well as have cash on hand.

The Trust will be holding a Special Meeting of unitholders on November 24, 2014 to vote on a special resolution to amend the investment restrictions in Eagle's Trust indenture to permit investment in Canadian energy assets.

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 month period ended September 30, 2014

- Over 80% of the Trust's current production is hedged at an average price of over $US 90 per barrel WTI through to June 30, 2015, and 30% is hedged for the second half of 2015 at an average price of over $US 87 per barrel WTI.
- Eagle disposed of its entire working interest in its Permian properties on August 29, 2014 for net proceeds of $150.1 million ($US 140 million) after closing adjustments.
- The Trust is in a strong financial position, with approximately $69.5 million ($US 62.0 million) cash on hand, debt free and a $61.6 million ($US 55 million) unused credit facility.
- Eagle suspended the Premium Distribution™ component of its Distribution Reinvestment Plan ("DRIP") and reduced the market discount from 5% to 2% on units acquired under the regular DRIP. DRIP participation is expected to be substantially reduced from 60% to the range of 5% to 8%, significantly reducing the number of units issued each month.
- To date, 91% of the $US 28 million capital program for 2014 has been executed with results performing to expectations.
- In recent news, Eagle announced that it will seek unitholder approval at a Special Meeting on November 24, 2014 to permit investment in Canadian assets to expand its range of opportunities in addition to continuing to actively acquire, operate and exploit U.S. oil and gas production in accordance with the Trust's growth strategy.

Operations update

Hardeman Properties

Eagle commenced drilling its first well in Hardeman County, Texas using newly processed and interpreted 3D seismic in late September. Results of this well are expected by mid-November. Eagle commenced drilling its second Hardeman County well in late October. Eagle continues to evaluate the newly processed seismic data to de-risk additional drilling opportunities. While primarily targeting Mississippian carbonates, an opportunity also exists for Pennsylvanian and Ordovician production.

Eagle began operating its first Hardeman property in January 2014 and its second Hardeman property in March 2014. From the time Eagle assumed operations, costs have been reduced on both properties and continue to trend downward as a result of reduced water disposal and power costs. These two components represent approximately 80% of field operating costs. Eagle has been optimizing water disposal techniques with the overall vision to have all water piped to Eagle owned and operated disposal wells across the field. Eagle plans to drill a salt water disposal well in 2015 pending permits and rig availability. Propane is utilized at wells remotely situated from the electricity grid. To reduce costs, Eagle acquired and repaired an inactive natural gas sharing system and recompleted a natural gas well to displace propane as fuel. Other initiatives include well-site electrification, the installation of additional natural gas sharing lines and relocating existing natural gas powered generators to further optimize fuel usage.

Salt Flat Properties

Eagle completed and placed one well on production at Salt Flat during the quarter. This well was a “sidetrack” well, and was a successful pilot project undertaken by Eagle to show that, in some cases, production can be added at a lower cost by drilling less expensive “sidetrack” wells instead of drilling new wells. Eagle continues to optimize pump size and power usage in the field and, earlier in the year, installed eight horizontal pumps with good success. In aggregate, the results of the Salt Flat capital program have exceeded expectations.

Year-over-year field operating expense reductions continue at Salt Flat with expenses expected to be 5% to 7% lower than in 2013. On a dollar basis, Eagle expects year-over-year field operating expense savings of approximately $US 1.0 million.

Eagle has negotiated a new power contract for all of its operated assets. This new contract is below five cents per kilowatt hour and will ensure that electrical costs do not fluctuate for the next three years. This is particularly important since electricity constitutes more than half of Salt Flat’s operating costs.

During the third quarter, Eagle conducted a high density 3D seismic program at Salt Flat with the intention of developing additional well locations. The program encompassed 8.3 square miles and was completed on time and on budget. The data is presently being processed, with interpretation to commence late in the fourth quarter.

Outlook

With the August 29, 2014 disposition of its entire working interest in its Permian properties, Eagle announced that it had withdrawn its current guidance and that it expected to provide revised guidance after the sale proceeds are re-deployed. The Trust’s working interest production following the disposition of the Permian properties was approximately 1,900 barrels of oil per day. Following the disposition, Eagle has approximately $69.5 million ($US 62.0 million) of cash on hand and a $61.6 million ($US 55 million) unused credit facility.

Eagle will be holding a Special Meeting of unitholders on November 24, 2014 to vote on a special resolution to amend the investment restrictions in Eagle’s Trust Indenture to permit the acquisition of Canadian energy assets. Eagle’s management and directors have significant experience acquiring and developing energy assets in Canada. Management believes opportunities in Canada are as attractive as opportunities in the U.S. because market conditions in Canada’s oil and gas sector have resulted in Canadian oil and gas assets being available at attractive prices. Management expects pricing differentials to continue to narrow over the coming years with the expansion of liquefied natural gas, rail and pipeline infrastructure. Management also believes that investing in Canada will diversify the Trust’s exposure to commodity prices, foreign exchange and interest rates.

Sensitivities

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

	Quarterly impact on ➔	**Funds flow from operations ($000's)**	**Funds flow from operations / unit[(1)]**
Gas price[(2)]	+ USD $0.10/Mcf Henry HUB	12	0.00
Oil price [(2)]	+ USD $1.00/bbl WTI	226	0.01
Gas production	+1000 Mcf/d	209	0.01
Oil production	+100 bbls/d	542	0.02
Currency [(2)]	+CDN weakens by $0.01	184	0.01
Interest rate	+1% prime	(131)	(0.00)

Notes:

(1) Per unit figures are based on 33,265,126 weighted average basic units outstanding for the nine months ended September 30, 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 3,069 boe/d.

Results of operations

Production

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	%	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013	%
Oil (bbl/d)	2,342	2,447	(4)	2,539	2,490	2
Natural gas (Mcf/d)	1,520	1,559	(3)	1,539	1,336	15
Natural gas liquids (bbl/d)	263	345	(24)	274	289	(5)
Oil equivalent sales volumes (boe/d @ 6:1)	**2,859**	3,052	(6)	**3,069**	3,002	2

Working interest sales volumes for the third quarter of 2014 averaged 2,859 boe/d (82% oil, 9% natural gas liquids, 9% natural gas), 6% below September 30, 2013 average sales volumes and 14% below the second quarter 2014 average sales volumes. Third quarter 2014 sales volumes are lower because they only include production from the Permian properties up to the August 29, 2014 disposition date. The Trust's working interest sales volume following the disposition of the Permian properties was approximately 1,900 boe/d.

Revenue ($000's)		**Three Months Ended September 30, 2014**		Three Months Ended September 30, 2013	%		**Nine Months Ended September 30, 2014**		Nine Months Ended September 30, 2013	%
Oil	$	21,965	$	24,957	(12)	$	73,214	$	68,788	6
Natural gas		564		513	10		1,886		1,324	42
Natural gas liquids		841		1,157	(27)		2,800		2,766	1
Other		196		-	100		441		-	100
Sales before royalties	**$**	**23,566**	$	26,627	(12)	**$**	**78,341**	$	72,878	7

Realized Prices										
Oil ($/bbl)	$	101.92	$	110.84	(8)	$	105.62	$	101.18	4
Natural gas ($/Mcf)		4.05		3.57	13		4.49		3.63	24
Natural gas liquids ($/bbl)		34.72		36.49	(5)		37.46		35.11	7
Other ($/bbl)		0.75		-	100		0.53		-	100
Sales before royalties ($/boe)		89.61		94.84	(6)		93.49		88.94	5
Royalties ($/boe)		(24.42)		(27.00)	(10)		(25.54)		(25.37)	1
Revenue ($/boe)	**$**	**65.19**	$	67.84	(4)	**$**	**67.95**	$	63.57	7

Benchmark Prices										
Oil – WTI ($US/bbl)	**$**	**97.17**	$	105.82	(8)	**$**	**99.60**	$	98.15	1
Natural gas – Henry HUB ($US/Mcf)	**$**	**3.95**	$	3.56	11	**$**	**4.42**	$	3.34	32

For the three months ended September 30, 2014, sales revenue decreased by 12% when compared to the prior year's comparative quarter and by 18% when compared to the second quarter of 2014. The decrease is attributable to lower volumes as the Permian properties were sold on August 29, 2014, as well as to lower realized oil prices resulting from the 8% decline in the WTI benchmark price over the third quarter of 2013. For the nine months ended September 2014, sales revenues increased by 7% when compared to the same period in the prior year as both production and realized prices improved over the prior year by 2% and 5%, respectively.

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

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

For Hardeman properties, the field marketing contracts from May through November 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 loss of $0.6 million ($2.38/boe) for the three months ended September 30, 2014 and a realized loss of $3.0 million ($3.59/boe) for the nine months ended September 30, 2014. See *Realized and unrealized risk management gain/loss.*

Realized prices are subject to fluctuations in foreign exchange rates as the Trust's revenue is converted to Canadian dollars, the presentation currency of the Trust. For the quarter ended September 2014, the benchmark WTI ($US/bbl) decreased by 8% from the prior year comparative quarter. This is comparable to the decrease in the realized oil price, as the increase in the differential between the Trust's realized oil price and the WTI benchmark was offset by a much weaker Canadian dollar. For the nine months ended September 30, 2014 and 2013, the benchmark WTI ($US/bbl) increased by 1%, yet the realized oil price increased by 4% due to the weaker Canadian dollar, offset by a widening LLS-WTI differential as noted above.

For the three and nine months ended September 30, 2014, revenue was reduced for the reclassification of oil transportation expenses by $2.18 per boe and $2.16 per boe, respectively. For the three and nine months ended September 30, 2013, this reclassification resulted in a revenue reduction of $2.09 per boe and $2.05 per boe, respectively. Refer to "Oil transportation expenses", below.

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

Operating costs

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013		%	**Nine Months Ended September 30, 2014**		Nine Months Ended September 30, 2013		%
	$	**/boe**	$	/boe		**$**	**/boe**	$	/boe	
Operating expenses		15.77		10.30	53		15.16		9.07	67
Transportation and marketing expenses		0.62		0.75	(17)		0.66		0.62	6
	$	**16.39**	$	11.05	48	**$**	**15.82**	$	9.69	63

The 48% and 63% increase in per boe operating costs for the three and nine months ended September 30, 2014 was primarily due to additional salt water disposal costs on the Hardeman properties and incremental expenses relating to the Permian properties, which were disposed of on August 29, 2014. Eagle continues to implement initiatives to reduce operating costs at its Salt Flat and Hardeman properties. Refer to the “Operations update” section of this MD&A.

Oil transportation expenses

Historically, the Trust has included oil transportation charges as a component of transportation and marketing expenses. Following a review of the Trust’s crude oil contracts during the third quarter, it was determined that the criteria for revenue recognition are met at the point of sale before the crude oil is transported by its purchasers, and oil transportation changes should be treated as a reduction of the Trust’s revenue rather than as a transportation and marketing expense. Consequently, the Trust has stated its revenue and transportation and marketing expense for the three and nine months ended September 30, 2014, and restated its revenue and transportation and marketing expense retroactively for the 2013 comparative periods, to reflect this reclassification. There is no net impact on funds flow from operations.

For the three and nine months ended September 30, 2014, transportation and marketing expenses were reduced for the reclassification of oil transportation expenses by $2.18 per boe and $2.16 per boe, respectively. For the three and nine months ended September 30, 2013, this reclassification resulted in an operating cost reduction of $2.09 per boe and $2.05 per boe, respectively.

Depreciation, depletion and amortization

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013		%	**Nine Months Ended September 30, 2014**		Nine Months Ended September 30, 2013		%
	$	**/boe**	$	/boe		**$**	**/boe**	$	/boe	
Depreciation, depletion and amortization		**34.41**		27.83	24		**33.97**		27.18	25

The depletion, depreciation, and amortization rate per boe for the three and nine months ended September 30, 2014 has increased over the prior year because the depletable asset base has grown by more than the relative increase to proved plus probable reserves.

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

Impairment

The recognition of a $20.6 million ($US 18.3 million) impairment occurred at the end of the second quarter 2014. The impairment specifically related to the disposition of the Permian properties as the disposition proceeds were less than the book value of the assets.

Field netback

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013		**Nine Months Ended September 30, 2014**		Nine Months Ended September 30, 2013	
($000's)	**$**	**$ /boe**	$	$ /boe	**$**	**$ /boe**	$	$ /boe
Sales before royalties	23,566	89.61	26,627	94.84	78,341	93.49	72,878	88.94
Royalties	(6,423)	(24.42)	(7,581)	(27.00)	(21,403)	(25.54)	(20,788)	(25.37)
Operating expenses	(4,148)	(15.77)	(2,892)	(10.30)	(12,705)	(15.16)	(7,432)	(9.07)
Transportation and marketing expenses	(164)	(0.62)	(209)	(0.75)	(553)	(0.66)	(505)	(0.62)
Field netback	**$ 12,831**	**$ 48.80**	$ 15,945	$ 56.79	**$ 43,680**	**$ 52.13**	$ 44,153	$ 53.88
Sales volumes (boe/d)		**2,859**		3,052		3,069		3,002

During the quarter, benchmark WTI averaged $US 97.17 per barrel and the Trust realized a field netback of $48.80 per barrel. For the nine months ended September 30, 2014, benchmark WTI averaged $US 99.60 per barrel and the Trust realized a field net back of $52.13 per barrel. When compared to the prior year comparative periods, the decrease in field netbacks is primarily due to increased operating expenses from the Hardeman properties, which were not operated by Eagle until January 2014, and the Permian properties, which were disposed of on August 29, 2014. Eagle continues to implement initiatives to reduce operating costs. Refer to the "Operations update" section of this MD&A.

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

Realized and unrealized risk management gain/loss

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

Commodity:

Oil Fixed Price	Volume	Contract Term	Price $US
NYMEX (1)	400 bbls/d	Jan 2014 to Dec 2014	$98.00
NYMEX (1)	500 bbls/d	Jan 2014 to Dec 2014	$91.15
NYMEX (1)	400 bbls/d	Jan 2014 to Dec 2014	$91.15
NYMEX (2)	250 bbls/d	Jan 2014 to Dec 2014	$90.00 - $94.95
NYMEX (2)	100 bbls/d	Jan 2014 to Dec 2014	$93.00 - $95.35
NYMEX (1)	190 bbls/d	Jan 2015 to Dec 2015	$85.40
NYMEX (2)	1,000 bbls/d	Jan 2015 to Jun 2015	$90.10 - $92.00
NYMEX (1)	400 bbls/d	Jul 2015 to Dec 2015	$87.90
NYMEX (2)	400 bbls/d	Jan 2015 to Jun 2015	$90.50 - $94.35

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

Foreign Exchange:

Foreign Exchange Type	Contract Term	Price $US
Collar	Oct 2014	$1.05 - $1.09
Collar	Nov 2014	$1.05 - $1.09
Collar	Dec 2014	$1.05 - $1.09

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	%	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	%
Realized gain (loss)	(612)	(920)	(33)	(2,962)	(711)	317
Unrealized gain (loss)	7,569	(3,795)	-	2,609	(3,772)	-
Net gain (loss) - Commodity	$ 6,957	$ (4,715)	-	$ (353)	$ (4,483)	92
Realized gain (loss)	(13)	-	(100)	(42)	-	(100)
Unrealized gain (loss)	(78)	-	(100)	(81)	-	(100)
Net gain (loss) - Foreign exchange	(91)	-	(100)	(123)	-	(100)
Total net gain (loss)	$ 6,866	$ (4,715)	-	$ (476)	$ (4,483)	(89)

On a year-over-year basis, the net value of the commodity price contracts has increased. The net value of the contracts is dependent upon current and forward commodity pricing and, in the case of realized gains and losses, the price of the contract relative to the benchmark oil price at time of settlement. Although the Trust currently has no intention of unwinding contracts, it is required to calculate and record, using a mark-to-market valuation, the fair value of the remaining term of the contracts at the end of each reporting period, thus changing the value of the unrealized portion of the commodity contracts at each balance sheet date. Since the second quarter of 2014, a weakened forward commodity pricing environment has caused the future value of these contracts to increase and a corresponding swing from a risk management liability at June 30, 2014 to a risk management asset at September 30, 2014.

Based on current estimated working interest production, Eagle is hedged at approximately 87% for the fourth quarter of 2014 at a weighted average price of $US 93.19 per barrel WTI. The Trust is also hedged at approximately 80% for the first half of 2015 at a weighted average price of $US 90.72 per barrel WTI, and at approximately 30% for the second half of 2015 at a weighted average price of $US 87.09 per barrel WTI.

On January 7, 2014, the Trust entered into a foreign exchange contract to mitigate the effects of foreign exchange rate ($CA/$US) fluctuations on monthly distribution payments. Since the second quarter of 2014, the foreign exchange contract had no significant impact on the cost of the Trust's monthly distributions as the Canadian dollar weakened throughout the third quarter and reduced the asset position on the balance sheet at September 30, 2014.

Finance expense

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	%	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	%
Finance expense	**$ 412**	$ 620	(34)	**$ 2,376**	$ 1,605	48
Per boe	**1.57**	2.21	(29)	**2.84**	1.96	45

For the three months ended September 30, 2014, total finance expense decreased over the prior year's comparative quarter due to the full retirement of the Trust's outstanding advances on its credit facility following the August 29, 2014 disposition of the Permian properties.

For the nine months ended September 30, 2014, finance expense increased over the prior year's comparative period due to additional borrowing to fund the two Hardeman property acquistions.

Administrative expenses

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	%	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	%
Administrative expenses	**$ 4,212**	$ 2,027	108	**$ 9,776**	$ 5,472	79
Per boe	**16.02**	7.22	122	**11.67**	6.68	75

Total administrative expenses for the third quarter ended September 30, 2014 were $4.2 million, a $1.2 million increase (40%) relative to the second quarter of 2014. This increase was due to $1.6 million of one-time transaction costs associated with the disposition of the Permian properties. See "Overview of the Trust".

For the nine months ended September 30, 2014, administrative expenses were $9.8 million, 79% above the nine month period ended September 30, 2013. This increase was due to one-time costs associated with the disposition of the Permian properties, as well as a one-time transaction cost in the previous quarter associated with an internal reorganization. Further, over the past year, engineering, geological, and business development staff were added to assist with full cycle property development, acceleration of the strategic focus on potential acquisitions and management of planned activities. Staff and related employment costs account for 47% of administrative expenses and professional service costs, audit, legal, engineering and tax fees account for 20%.

Unit-based compensation

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	%	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013	%
Unit-based compensation expense (recovery)	**$ (2,112)**	$ 3,940	(154)	**$ (4,886)**	$ 5,336	(192)

The recovery of non-cash unit based compensation expense for the three and nine months ended September 30, 2014 was due to: (i) a lower unit price at September 30, 2014 when compared to the unit price of the prior periods, and (ii) a reduction in the expected unit price volatility since the 2014 calculation incorporates the trading history of the Trust's units rather than incorporating the trading history of a representative sample of peer group entities as was done last year.

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

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

The Trust is, however, required to re-determine the fair value of the liability each quarter relating to: (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 nine months ended September 30, 2014, the recovery was primarily due to the lower year to date price of the Trust's units.

During the third quarter, $0.2 million was paid out in cash for amounts related to vested restricted unit rights and $0.5 million was recorded for the nine months ended September 30, 2014 (three and nine months ended September 30, 2013 - $0.8 million and $1.0 million respectively). 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 corporate U.S. taxes are expected to be payable in respect of income attributable to Eagle's properties 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. The Trust may be subject to state taxes (Texas) or an alternative minimum tax depending on the deductibility of certain capital expenditures. The Texas state tax and alternative minimum tax rates are at 1% and 20%, respectively. In the case of alternative minimum tax any amount paid can offset any future corporate tax payable. These taxes are not expected to be material.

The Trust is holding a Special Meeting of Unitholders on November 24, 2014 at which Unitholders will be asked to consider and vote on a special resolution to amend the investment restrictions in the Trust Indenture to permit the Trust (through its subsidiaries) to invest in Canadian energy assets. The Trust's proposed Canadian investments will be structured such that the SIFT tax will not apply to the Trust or its affiliates. The Trust's Canadian corporate subsidiaries will be taxed in the same manner as other Canadian oil and gas corporations, with taxable income being reduced by claiming permitted deductions. The Trust's Canadian corporate subsidiaries, like many Canadian petroleum exploration and production companies, will maximize available deductions in order to minimize corporate tax.

Summary of quarterly results

($000's except for boe/d and per unit amounts)	Q3/2014	Q2/2014	Q1/2014	Q4/2013	Q3/2013	Q2/2013	Q1/2013	Q4/2012
Sales volumes – boe/d	2,859	3,341	3,010	2,994	3,052	3,022	2,928	2,986
Revenue, net of royalties	17,143	20,777	19,018	17,318	19,046	16,698	16,346	16,039
per boe	65.19	68.34	70.20	62.87	67.84	60.73	62.03	58.39
Field netback	12,832	16,144	14,705	13,106	15,945	14,352	13,857	12,817
per boe	48.80	53.10	54.29	47.58	56.79	52.20	52.59	46.67
Funds flow from operations	7,476	10,471	10,341	8,794	11,615	11,977	11,884	9,905
per boe	28.43	34.44	38.18	31.93	41.37	43.56	45.10	36.06
per unit – basic	0.22	0.32	0.32	0.28	0.37	0.39	0.40	0.34
per unit – diluted	0.16	0.28	0.25	0.28	0.37	0.39	0.40	0.32
Income (loss)	8,104	(23,158)	2,218	156	(3,241)	3,919	4,080	(403)
per unit – basic	0.24	(0.70)	0.07	0.00	(0.10)	0.13	0.14	(0.02)
per unit - diluted	0.18	(0.70)	0.02	0.00	(0.10)	0.13	0.14	(0.02)
Cash distributions declared	9,036	8,775	8,555	8,376	8,204	8,026	7,828	7,653
per issued unit	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625
Current assets	76,566	8,802	9,116	9,889	9,950	11,443	9,913	14,464
Current liabilities	13,587	32,878	33,348	30,461	20,942	19,874	11,982	17,512
Total assets	240,458	320,182	356,332	335,679	306,021	311,271	283,112	284,802
Total non-current liabilities	2,565	80,126	79,684	70,521	55,069	50,654	39,873	42,111
Unitholders' equity	224,306	207,178	243,300	234,697	230,010	240,743	231,257	225,179
Units outstanding for accounting purposes	34,821	33,739	32,836	32,149	31,469	30,707[(1)]	29,960[(1)]	29,269[(1)]
Units issued	34,821	33,739	32,836	32,149	31,469	30,813	30,066	29,375

Note:

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

Field netback and funds flow from operations are non-IFRS measures. See "Non-IFRS Financial Measures".

For the three months ended September 30, 2014, sales volumes decreased 14% when compared to the previous quarter because third quarter sales volumes only include production from the Permian properties up to the August 29, 2014 disposition date. The Trust's working interest sales volumes following the disposition of the Permian properties was approximately 1,900 boe/d. Prior to the third quarter 2014, with the exception of the fourth quarter 2013, which encountered non-recurring weather related delays and non-owned infrastructure problems, production has generally increased commensurate with well tie-ins and acquisitions. Refer to the sections of this MD&A titled "Liquidity and capital resources - Capital Expenditures, Acquisitions and Activity Summary" for additional information.

Generally, in times of steady or increasing prices, funds flow from operations per boe grows as sales volumes increase and shrinks when sales volumes decrease. This is because certain expenses tend to be more fixed in nature (such as operating costs, and general and administrative expenses) and do not decrease as sales volumes decrease. Third quarter 2014 funds flow from operations was further tempered by one-time transaction costs associated with the disposition of the Trust's Permian properties and lower realized commodity prices.

Income (loss) on a quarterly basis often does not move directionally or by the same amount as movements in funds flow from operations. This is primarily due to non-cash items that factor into the calculation of income (loss), and other items which are required to be fair valued at each quarter end. By way of example, third quarter 2014 funds flow from operations decreased 29% from the second quarter while Eagle reported a positive earnings swing of $31.3 million for the same period. This occurred for the following reasons. Firstly, a weaker forward commodity price environment increased the fair market valuation of Eagle's forward commodity contracts. Secondly, an impairment was recognized in the second quarter on Eagle's oil and gas properties in relation to the disposition of the Permian properties. Lastly, the lower unit price at the end of the third quarter of 2014 caused a higher unit-based compensation recovery to be recorded upon performing a fair market valuation of future unit-based payments.

Liquidity and capital resources

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

Management's objective is to target an external debt to cash flow ratio below 2.0 times.

The Trust believes 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 September 30, 2014		Three Months Ended September 30, 2013		**Nine Months Ended September 30, 2014**		Nine Months Ended September 30, 2013	
($000's)	**$**	**$ /boe**	$	$ /boe	**$**	**$ /boe**	$	$ /boe
Field netback	12,832	48.80	15,945	56.79	43,680	52.13	44,153	53.88
Cash settled award payments	(166)	(0.62)	(798)	(2.84)	(528)	(0.62)	(1,023)	(1.25)
Administrative expenses	(4,212)	(16.02)	(2,027)	(7.22)	(9,776)	(11.67)	(5,472)	(6.68)
Realized risk management gain (loss)	(625)	(2.39)	(920)	(3.28)	(3,004)	(3.59)	(711)	(0.87)
Finance expense	(325)	(1.24)	(540)	(1.92)	(2,002)	(2.39)	(1,383)	(1.69)
Realized foreign exchange gain (loss)[1]	(27)	(0.10)	(45)	(0.16)	(82)	(0.10)	(87)	(0.10)
Funds flow from operations	**$ 7,476**	**$ 28.43**	$ 11,615	$ 41.37	**$ 28,288**	**$ 33.76**	$ 35,477	$ 43.29

Note:

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

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

Credit facility

As of September 30, 2014, the Trust had approximately $69.5 million ($US 62.0 million) cash on hand, no debt and $61.6 million ($US 55 million) credit facility, which is held indirectly through its US subsidiary with a syndicate of Canadian chartered banks.

As a result of the Trust's semi-annual evaluation on October 1, 2014, the borrowing base, after giving effect to the disposition of the Permian properties, was redetermined to $61.6 million ($US 55 million), with all other terms and conditions remaining unchanged. The next redetermination will be April 1, 2015 and the credit facility has a maturity date of May 27, 2016.

Working capital

At September 30, 2014, the Trust had a working capital surplus, excluding non-cash unit-based payments and non-cash risk management asset, of approximately $66.0 million and no amounts drawn on its bank credit facility described above.

Unitholders' equity

All Trust capital issuances for the three and nine months ended September 30, 2014 were issued pursuant to the distribution reinvestment plan as detailed below.

As a result of its DRIP, the Trust received proceeds resulting from the issuance of units from treasury to those unitholders who have opted to participate in the DRIP. Effective September 1, 2014, Eagle suspended the Premium Distribution™ component of the DRIP and reduced the market discount that units can be acquired for under the regular distribution reinvestment component from 5% to 2%. Eagle estimates participation in the DRIP to be substantially reduced from 60% to the range of 5% to 8%, significantly reducing the number of units issued each month.

A summary of the number of units issued, proceeds resulting from the issuance of units and average price per unit resulting from the Plan during the three and nine months ended September 30, 2014 and September 30, 2013 were as follows:

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	%	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013	%
Number of units issued	1,081,581	655,983	65	2,671,648	2,094,313	28
Fair market value of units issued under the DRIP	2,381	-	100	2,381	-	100
Net proceeds from issuance of Trust Capital (000's)	$ 6,041	$ 5,035	20	$ 16,612	$ 15,771	5
Average price per unit	$ 5.58	$ 7.74	(28)	$ 6.23	$ 7.20	(13)

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 third quarter (for the June, July and August 2014 record dates) totaled approximately $8.9 million.

At September 30, 2014, the Trust had issued 34,820,557 units (September 30, 2013 - 31,468,873).

As at the date of this MD&A, 34,862,833 units are issued and 3,445,084 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 September 30, 2014	Three Months Ended September 30, 2013	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013
(000's)	**$**	$	$	$
Income (loss) for the period	8,104	(3,241)	(12,836)	4,758
Cash distributions paid	(8,941)	(8,146)	(26,132)	(23,874)
Shortfall of income over cash distributions paid	(837)	(11,387)	(38,968)	(19,116)
Funds flow from operations[(1)]	7,476	11,615	28,288	35,477
Changes in working capital	1,304	(2,805)	1,710	(1,085)
Abandonment expenditures	-	-	-	(9)
Net cash provided by operating activities	8,780	8,810	29,998	34,383
Cash distributions paid	(8,941)	(8,146)	(26,132)	(23,874)
Excess (shortfall) of net cash provided by operating activities over cash distributions paid	(161)	664	3,866	10,509

Note:

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

For the three and nine months ended September 30, 2014 and 2013, cash distributions paid exceeded income for the period due to the non-cash items that 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), as well as those that are required to be fair valued at each period end. Examples of non-cash items include depreciation, depletion and amortization, impairment, unit-based compensation, and unrealized risk management losses, all of which have no impact on cash available to pay distributions.

For the three months ended September 30, 2014, cash distributions paid exceeded net cash provided by operating activities by approximately $161,000 due to third quarter operations only including production from the Permian properties up to the August 29, 2014 disposition date, one-time transaction costs associated with the disposition of the Permian properties, which increased general and administrative expenses by approximately $1.6 million, and lower realized commodity prices.

Cash distributions paid in the third quarter of 2014 were 10% higher than third quarter of 2013 due to the higher number of outstanding units. As a result of the current low unit price environment, the Trust suspended the Premium Distribution™ component of its DRIP effective September 12, 2014, and amended the DRIP to reduce the market discount that the Trust's units can be acquired for under the regular distribution reinvestment component from 5% to 2%.

Capital expenditures

Capital expenditures during the three and nine months ended September 30, 2014 and September 30, 2013 were as follows:

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	%	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013	%
(000's)	**$**	$		**$**	$	
Exploration and evaluation[1]	-	7	(100)	16	63	(75)
Acquisition - Hardeman	-	-	-	5,409	-	100
Acquisition - Permian - remainder	-	-	-	-	8,830	(100)
Disposition - Permian	(150,147)	-	(100)	(150,147)	-	(100)
Intangible drilling and completions	1,748	8,836	(80)	15,302	25,180	(39)
Seismic	337	-	100	3,284	-	100
Well equipment and facilities	92	2,356	(96)	1,501	3,468	(57)
Other	29	(259)	-	51	197	(74)
	$ (147,941)	10,940	-	(124,584)	37,738	-

Notes:

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

During the third quarter of 2014, the Trust spent $1.8 million on drilling, completions, tie-ins and recompletions. Of this total, $0.6 million was for drilling and tie-in of one Salt Flat well, $0.7 million was for drilling preparation work on two Hardeman wells (which are currently underway), and $0.5 million was for recompleting existing Hardeman wells. Additionally, $0.3 million was for seismic processing for the Hardeman properties and preparation for the seismic shoot on the Salt Flat properties. Refer to the "Operations update" section of this MD&A.

Eagle is well positioned for growth with financial flexibility and operational strength. The Trust will continue to actively pursue acquisitions in the U.S. and seek unitholder approval on November 24, 2014 to expand into Canada.

Disposition

On August 29, 2014, the Trust's U.S. operating subsidiary closed the sale of its entire working interest in oil and natural gas properties in the Permian Basin, located near Midland, Texas, for net proceeds of $150.1 million ($US 140 million) after closing adjustments.

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

Identifiable assets and liabilities disposed of ($CA):

Oil and gas properties	$	151,336
Decommissioning liabilities		(1,189)
	$	**150,147**

The Trust's working interest production following the closing of the disposition of the Permian properties was approximately 1,900 barrels of oil per day.

Acquisition

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 $5.4 million. The acquisition increased Eagle's 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 as follows:

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

Activity Summary

Wells drilled (rig-released)	**Three Months Ended September 30, 2014**		Three Months Ended September 30, 2013		**Nine Months Ended September 30, 2014**		Nine Months Ended September 30, 2013	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Salt Flat	1	0.8	3	2.8	3	2.4	6	5.4
Permian	-	-	2	2.0	2	2.0	5	4.8
Hardeman	-	-	-	-	-	-	-	-
Total	**1**	0.8	5	4.8	**5**	**4.4**	11	10.2

Wells brought on-stream	**Three Months Ended September 30, 2014**		Three Months Ended September 30, 2013		**Nine Months Ended September 30, 2014**		Nine Months Ended September 30, 2013	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Salt Flat	1	0.8	3	2.8	3	2.4	6	5.2
Permian	-	-	3	3.0	2	2.0	6	6.0
Hardeman	-	-	-	-	-	-	-	-
Total	**1**	**0.8**	6	5.8	**5**	**4.4**	12	11.2

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

Commitments

The Trust has committed to future payments as follows:

(000's)		**Total**		**Less than 1 year**		**1 – 3 years**		**After 3 years**
Operating leases [(1)(2)]		2,667		804		1,620		243
Total contractual obligations	**$**	**2,667**	**$**	**804**	**$**	**1,620**	**$**	**243**

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 40 months and approximately $1.6 million remaining at September 30, 2014.

(2) Houston, Texas office lease: the Trust entered into a lease in Houston 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 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 1.5 million with 39 months and approximately $US 0.9 million remaining at September 30, 2014. In $CA the remaining future minimum lease payments approximate $1.1 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.12.

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 any standardized meaning prescribed by IFRS and may not 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 Interim Financial Statements:

($000’s)	**Three Months Ended September 30, 2014**	Three Months Ended September 30, 2013	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013
Earnings (Loss)	**$ 8,104**	$ (3,241)	**$ (12,836)**	$ 4,758
Add back (deduct) items not involving cash:				
Unit-based compensation - non-cash portion	(2,278)	3,141	(5,414)	4,313
Unrealized risk management loss (gain)	(7,491)	3,795	(2,528)	3,772
Depreciation, depletion and amortization and impairment	9,054	7,839	48,692	22,412
Finance expense	87	81	374	222
Funds flow from operations	**$ 7,476**	$ 11,615	**$ 28,288**	$ 35,477
Add back (deduct) items not directly related to field operations:				
Realized foreign exchange loss (gain)	27	45	82	87
Finance expense (cash portion)	325	540	2,002	1,383
Risk management (gain) loss-realized	625	920	3,004	711
Administrative expenses	4,212	2,027	9,776	5,472
Cash settled award payments	166	798	528	1,023
Field netback	**$ 12,831**	$ 15,945	**$ 43,680**	$ 44,153

Internal controls over financial reporting and disclosure controls and procedures

During the period beginning on July 1, 2014 and ended on September 30, 2014, 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 control systems, 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 were no changes to the Trust’s critical accounting estimates and judgments during the third 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 the Interim Financial Statements are consistent with those of the previous financial year.

Accounting pronouncements adopted

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

Accounting pronouncements not yet adopted

- 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. Adopting this standard is not expected to have a material impact on the Trust's consolidated financial statements.
- 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.

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

This MD&A includes 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 Special Meeting of the unitholders to be held of November 24, 2014;
- Eagle's drilling plans on its Hardeman and Salt Flat properties;
- Eagle's expectations to continue to reduce operating costs on its Hardeman and Salt Flat properties;
- Management's view in respect of the market conditions and opportunities for the Trust in the Canadian oil and gas sector;
- Management's expectation that future pricing differentials will narrow and that investing in Canada will mitigate the Trust's commodity price, foreign exchange and interest rate risk through diversification;
- the Trust's commodity and foreign exchange hedging contracts;
- estimated future participation in the DRIP;
- Eagle's drilling plans and potential locations;
- Management's objective to target an external debt to cash flow ratio below 2.0 times;
- 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; and
- Eagle is well positioned for growth with financial flexibility and operational strenght

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 distribution reinvestment program; and

- the regulatory framework governing taxes in the U.S. and Canada and the Trust's status as a "mutual fund 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, which include:

- 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;
- unexpected operational delays and challenges;
- taxability of the Trust and its subsidiaries;
- 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, distribution reinvestment program 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. Unlike fixed income securities, Eagle has no obligation to distribute any fixed amount and reductions in, or suspension of, cash distributions may occur that would reduce future yield.

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 and nine months ended September 30, 2014 and September 30, 2013

Eagle Energy Trust

Condensed Consolidated Balance Sheets

(Thousands of Canadian dollars) (unaudited)

	Note	**September 30, 2014**	December 31, 2013
ASSETS			
Current assets			
Cash		$ 69,535	$ 1,435
Trade and other receivables		5,287	7,826
Prepaid expenses		695	628
Risk management asset	3	1,049	-
		76,566	**9,889**
Non-current assets			
Risk management asset		7	-
Exploration and evaluation		551	508
Oil and gas properties	10	162,473	324,349
Property, plant and equipment		244	327
Other intangible assets		617	606
		163,892	**325,790**
Total Assets		**$ 240,458**	**$ 335,679**
LIABILITIES			
Current liabilities			
Trade and other payables		$ 6,305	$ 5,929
Distributions payable	11	3,066	2,813
Unit-based payments	6	4,216	9,630
Risk management liability	3	-	1,453
Current debt	12	-	10,636
		13,587	**30,461**
Non-current liabilities			
Long-term debt	12	-	67,485
Decommissioning liability	13	2,565	3,036
		2,565	**70,521**
Total Liabilities		**$ 16,152**	**$ 100,982**
UNITHOLDERS' EQUITY			
Trust capital	14	$ 316,420	$ 297,447
Currency reserves		23,318	11,100
Accumulated earnings		(6,232)	6,604
Accumulated cash distributions	15	(109,200)	(80,454)
Total Unitholders' Equity		**$ 224,306**	**$ 234,697**
Total Liabilities and Unitholders' Equity		**$ 240,458**	**$ 335,679**

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

See Note 16 "Commitments" and Note 17 "Subsequent event".

Eagle Energy Trust

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

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

	Note	**Three Months Ended September 30, 2014**	Three Months Ended September 30, 2013	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013
Revenue		$ 23,566	$ 26,627	$ 78,341	$ 72,878
Royalties		(6,423)	(7,581)	(21,403)	(20,788)
		17,143	**19,046**	**56,938**	**52,090**
Operating expenses		4,148	2,892	12,705	7,432
Transportation and marketing expenses		164	209	553	505
Administrative expenses		4,212	2,027	9,776	5,472
Impairment (recovery)		(44)	-	20,082	-
Depreciation, depletion and amortization		9,098	7,839	28,610	22,412
Operating profit		**(435)**	**6,079**	**(14,788)**	**16,269**
Unit based compensation expense (recovery)	6	(2,112)	3,940	(4,886)	5,336
Finance expense	7	412	620	2,376	1,605
Risk management loss (gain)	3	(6,866)	4,715	476	4,483
Foreign exchange loss net		27	45	82	87
Earnings (Loss) before taxes		**8,104**	**(3,241)**	**(12,836)**	**4,758**
Income tax expense (recovery)	8	-	-	-	-
Earnings (Loss)		**$ 8,104**	**$ (3,241)**	**$ (12,836)**	**$ 4,758**
Other comprehensive income					
Items that may be reclassified subsequently to earnings					
Foreign currency translation gain (loss)		12,039	(5,138)	12,218	8,360
Comprehensive income (loss)		**$ 20,143**	**$ (8,379)**	**$ (618)**	**$ 13,118**
Earnings (Loss) per unit					
Basic	9	**$ 0.24**	**$ (0.10)**	**$ (0.39)**	**$ 0.16**
Diluted		**0.18**	**(0.10)**	**(0.44)**	**0.16**

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

Eagle Energy Trust

Condensed Consolidated Statements of Changes in Unitholders' Equity

For the nine months ended September 30, 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 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	-	-	-	4,758	-	4,758	4,758
Foreign currency translation gain		-	-	8,360	-	-	-	8,360
Total comprehensive income		-	-	8,360	4,758	-	4,758	13,118
Issuance of trust capital		2,200	15,837	-	-	-	-	15,837
Trust unit issuance costs		-	(66)	-	-	-	-	(66)
Unitholder distributions		-	-	-	-	(24,058)	(24,058)	(24,058)
		2,200	15,771	-	-	(24,058)	(24,058)	(8,287)
Balance at September 30, 2013		**31,469**	**292,297**	**3,343**	**6,448**	**(72,078)**	**(65,630)**	**$ 230,010**
Balance at December 31, 2013		**32,149**	**297,447**	**11,100**	**6,604**	**(80,454)**	**(73,850)**	**234,697**
Earnings (Loss)	9	-	-	-	(12,836)	-	(12,836)	(12,836)
Foreign currency translation loss		-	-	12,218	-	-	-	12,218
Total comprehensive income		-	-	12,218	(12,836)	-	(12,836)	(618)
Issuance of trust capital	14	2,672	19,010	-	-	-	-	19,010
Trust unit issuance costs	14	-	(37)	-	-	-	-	(37)
Unitholder distributions	11	-	-	-	-	(28,746)	(28,746)	(28,746)
			18,973	-	-	(28,746)	(28,746)	(9,773)
Balance at September 30, 2014		**34,821**	**316,420**	**23,318**	**(6,232)**	**(109,200)**	**(115,432)**	**224,306**

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

Eagle Energy Trust

Condensed Consolidated Cash Flow Statements

For the three months and nine months ended September 30, 2014 and September 30, 2013
(Thousands of Canadian dollars) (unaudited)

	Note	**Three Months Ended September 30, 2014**	Three Months Ended September 30, 2013	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013
Cash flows from operating activities					
Earnings (loss)		$ 8,104	$ (3,241)	$ (12,836)	$ 4,758
Adjustments for non-cash items:					
Impairment		(44)	-	20,082	-
Depreciation, depletion and amortization		9,098	7,839	28,610	22,412
Unit-based compensation – non-cash portion		(2,278)	3,141	(5,414)	4,313
Unrealized risk management loss (gain)		(7,491)	3,795	(2,528)	3,772
Finance expense		87	81	374	222
		7,476	11,615	28,288	35,477
Changes in working capital:					
Trade and other receivables		3,237	(6)	2,875	981
Prepaid expenses		(68)	(173)	(35)	(26)
Trade and other payables		(1,866)	(2,626)	(1,130)	(2,040)
		1,303	(2,805)	1,710	(1,085)
Cash generated from operations		**8,779**	8,810	**29,998**	34,392
Abandonment expenditures		-	-	-	(9)
Income taxes paid		-	-	-	-
Net cash generated by operating activities		**$ 8,779**	**$ 8,810**	**$ 29,998**	**$ 34,383**
Cash flows from investing activities					
Additions to exploration and evaluation		-	(7)	(16)	(63)
Additions to oil and gas properties		(2,177)	(11,192)	(20,087)	(28,648)
Additions to property, plant and equipment		(29)	259	(51)	(197)
Acquisition of oil and gas assets	4	-	-	(5,409)	(8,830)
Disposition of oil and gas assets	4	150,147	-	150,147	-
Change in non-cash working capital		505	-	1,233	-
Net cash used in investing activities		**$ 148,446**	**$ (10,940)**	**$ 125,817**	**$ (37,738)**
Cash flows from financing activities					
Debt		(84,700)	5,299	(78,121)	10,905
Proceeds from issuance of units		6,039	5,894	16,648	15,837
Trust unit issuance costs		-	(44)	(37)	(66)
Cash distributions to unitholders		(8,941)	(8,146)	(26,132)	(23,874)
Change in non-cash working capital		-	(860)	-	(860)
Deferred financing charges		(5)	(94)	(302)	(156)
Net cash (used in)/generated by financing activities		**$ (87,607)**	**$ 2,049**	**$ (87,944)**	**$ 1,786**
Net increase (decrease) in cash and cash equivalents		**69,618**	(81)	**67,871**	(1,569)
Effects of exchange rates on cash and cash equivalents		(83)	(143)	229	47
Cash at beginning of the period		-	2,709	1,435	4,007
Cash at end of the period		**$ 69,535**	**$ 2,485**	**$ 69,535**	**$ 2,485**

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

Eagle Energy Trust

Notes to Condensed Consolidated Financial Statements (unaudited)

For the three and nine months ended September 30, 2014 and September 30, 2013
(in Canadian dollars)

1. Reporting entity / Structure of the Trust

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

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

Throughout these notes to the 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 Trust's subsidiaries completed an internal reorganization on June 16, 2014, pursuant to which the Trust's new indirect U.S. subsidiary, Eagle Hydrocarbons Inc., acquired all of the assets and assumed all of the obligations of Eagle Energy Acquisitions LP and its general partner, Eagle Hydrocarbons LLC. Management and the directors of Eagle Hydrocarbons Inc. remain the same as management and the directors of Eagle Hydrocarbons LLC. In due course, Eagle Energy Acquisitions LP and Eagle Hydrocarbons LLC will be wound up.

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 will be holding a Special Meeting of unitholders on November 24, 2014 to vote on a special resolution to amend the investment restrictions in Eagle's Trust indenture to permit investment in Canadian energy assets. See note 17 "Subsequent event".

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, Eagle Hydrocarbons Inc.

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 November 6, 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.

Historically, the Trust has included oil transportation charges as a component of transportation and marketing expenses. Following a review of the Trust's crude oil contracts during the third quarter, it was determined that the criteria for revenue recognition are met at the point of sale before the crude oil is transported by its purchasers and any charges levied by its purchasers past the point of sale should be treated as a reduction of the Trust's revenue rather than as a transportation and marketing expense. Consequently, the Trust has stated its revenue and transportation and marketing expense for the three and nine months ended September 30, 2014, and restated its revenue and transportation and marketing expense retroactively for the comparative periods, to reflect this adjustment.

For the period ended September 30, 2014 and September 30, 2013, the impact of the oil transportation adjustment to revenue and transportation and marketing expenses was a $1.5 million and $1.4 million reduction, respectively.

Accounting pronouncements adopted

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

Accounting pronouncements not yet adopted

- 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. Adopting this standard is not expected to have a material impact on the Trust's consolidated financial statements.
- 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.

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

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 significant changes in the Trust's exposure to each of the above risks since the year ended December 31, 2013.

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 September 30, 2014, 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 September 30, 2014, the contractual undiscounted cash outflow for financial liabilities was reduced when compared to year-end, as the Trust's outstanding advances on its credit facility were retired.

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 September 30, 2014

Commodity Contracts

As at September 30, 2014, the Trust has entered into the following financial contracts to mitigate the effects of fluctuating prices on a portion of its production:

Oil Fixed Price	*Volume*	*Measure*	*Beginning*	*Term*	*Floor $US*	*Ceiling $US*	*Current net present value $000's $CA*	*Non-current net present value $000's $CA*
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	98.00	98.00	321	-
NYMEX (i)	500	bbls/d	Jan-14	Dec-14	91.15	91.15	48	-
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	91.15	91.15	39	-
NYMEX (ii)	250	bbls/d	Jan-14	Dec-14	90.00	94.95	37	-
NYMEX (ii)	100	bbls/d	Jan-14	Dec-14	93.00	95.35	34	-
NYMEX (i)	190	bbls/d	Jan-15	Dec-15	85.40	85.40	(152)	(31)
NYMEX (ii)	1,000	bbls/d	Jan-15	Jun-15	90.10	92.00	498	-
NYMEX (i)	400	bbls/d	Jul-15	Dec-15	87.90	87.90	27	38
NYMEX (ii)	400	bbls/d	Jan-15	Jun-15	90.50	94.35	279	-
Commodity - unrealized risk management asset							1,131	7

(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 September 30, 2014, the Trust has entered into the following contracts 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	943	Oct-14	1.05	1.09	(25)	-
Collar	950	Nov-14	1.05	1.09	(27)	-
Collar	956	Dec-14	1.05	1.09	(30)	-
Foreign exchange - unrealized risk management liablility					(82)	-

Total Unrealized Risk Management Asset

		Current net present value $000's $CA	**Non-current net present value $000's $CA**
Commodity		1,131	7
Foreign exchange		(82)	-
Total unrealized risk management asset	**$**	**1,049**	**7**

Earnings Impact of Realized and Unrealized Risk Management Gain

$000's	Three Months Ended September 30, 2014			Three Months Ended September 30, 2013		
	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)
Net effect - commodity	612	(7,569)	(6,957)	920	3,795	4,715
Net effect - foreign exchange	13	78	91	-	-	-
Net effect - risk management	**$ 625**	**(7,491)**	**(6,866)**	$ 920	3,795	4,715

$000's	Nine Months Ended September 30, 2014			Nine Months Ended September 30, 2013		
	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)
Net effect - commodity	2,962	(2,609)	353	711	3,772	4,483
Net effect - foreign exchange	42	81	123	-	-	-
Net effect - risk management	**$ 3,004**	**(2,528)**	**476**	$ 711	3,772	4,483

Determination of fair values

The net fair value of Eagle's unrealized risk management positions at September 30, 2014 is an asset of $1,138,847 (December 31, 2013 - $1,453,286 liability) for commodity contracts and a liability of $82,406 (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, distribution 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 accounts 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. Disposition and Acquisition

Disposition

On August 29, 2014, the Trust's U.S. operating subsidiary closed the sale of its entire working interest in oil and natural gas properties in the Permian Basin, located near Midland, Texas, for net proceeds of $150.1 million ($US 140 million) after closing adjustments.

The disposition has been accounted for as follows:

Identifiable assets and liabilities disposed of ($CA):

Oil and gas properties	$ 151,336
Decommissioning liabilities	(1,189)
	$ 150,147

Acquisition

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

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

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

The amount of revenue, net of royalties and operating income included in the consolidated statement of comprehensive earnings (loss) for the nine months ended September 30, 2014 from this acquisition was approximately $1.4 million and $0.8 million respectively. It is impracticable to determine the effect of this transaction on net income in the current reporting period.

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 and Luling, 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 September 30, 2014**	Three Months Ended September 30, 2013	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013
Units issued on performance option surrender	6(a)	$ -	$ 151	$ -	$ 270
Restricted unit rights	6(b)	(162)	892	(637)	841
Unit options	6(c)	(1,503)	2,411	(3,210)	3,344
Unit rights	6(d)	(447)	486	(1,039)	881
Total unit-based compensation expense (recovery)		**$ (2,112)**	$ 3,940	**$ (4,886)**	$ 5,336

The following table reconciles the unit-based payments liability.

$ 000's	Note	**September 30, 2014**	December 31, 2013
Units issued on performance option surrender	6(a)	$ -	$ -
Restricted unit rights	6(b)	105	1,240
Unit options	6(c)	3,788	6,998
Unit rights	6(d)	323	1,392
Total unit-based payments liability		**$ 4,216**	$ 9,630

Note (a)

Units issued upon surrender of performance options

At September 30, 2014, no escrowed units were outstanding. The following schedule shows the continuity of escrowed units issued upon surrender of performance options:

	Nine Months Ended September 30, 2014	Year Ended December 31, 2013	Nine Months Ended September 30, 2013
Balance, beginning of period	-	105,417	105,417
Issued	-	-	-
Transferred to the Trust capital account	-	(105,417)	(105,417)
Balance, end of period	**-**	-	-

Note (b)

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

For the nine months ended September 30, 2014, $498,076 was paid to the RUR holders (year ended December 31, 2013 - $1,110,734, nine months ended September 30, 2013 – $944,716).

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

	Nine Months Ended September 30, 2014	Year Ended December 31, 2013	Nine Months Ended September 30, 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	632,500

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

	September 30, 2014	December 31, 2013	September 30, 2013
Fair value at the balance sheet date	$ 4.66	$ 5.72	$ 5.85
Volatility	28%	32%	32%
Life of RURs	6.3 years	7.0 years	7.3 years
Risk-free interest rate	2.17%	2.70%	2.66%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Effective January 1, 2014, the expected unit price volatility was calculated using the trading history of the Trust’s units from November 24, 2010 to September 30, 2014. Prior to January 1, 2014, a representative sample of peer group entities was used in order to determine expected unit price volatility.

Note (c)

Unit option plan

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

	Nine Months Ended September 30, 2014		Year Ended December 31, 2013		Nine Months Ended September 30, 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	(31,666)	6.19	(249,918)	7.69	(249,918)	4.40
Exercised	-	-	--	-	-	-
Granted	350,000	5.61	1,162,000	6.72	717,000	6.19
Outstanding at end of period	**3,445,084**	**$ 6.20**	3,126,750	$ 7.05	2,681,750	$ 7.15
Exercisable at end of period	**1,870,179**	**$ 6.22**	1,411,010	$ 7.00	976,259	$ 7.39

The range of exercise prices of the outstanding options is as follows at September 30, 2014:

	Weighted average exercise price	Weighted average contractual life (years)
$5.13 - $7.78	**$ 6.20**	**7.8**

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

	September 30, 2014	December 31, 2013	September 30, 2013
Fair value - at balance sheet date	$ 1.67	$ 3.76	$ 4.07
Unit trading price - closing	$ 5.36	$ 8.07	$ 8.57
Exercise price – weighted average	$ 6.20	$ 7.05	$ 7.15
Volatility	28%	32%	32%
Option life – weighted average	7.8 years	8.4 years	8.3 years
Distributions – none estimated, due to declining strike price feature	0%	0%	0%
Risk-free interest rate	2.17%	2.70%	2.66%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Effective January 1, 2014, the expected unit price volatility was calculated using the trading history of the Trust's units from November 24, 2010 to September 30, 2014. Prior to January 1, 2014, a representative sample of peer group entities was used in order to determine expected unit price volatility.

Note (d)

Unit Rights (URs) plan

For the nine months ended September 30, 2014, $29,573 was paid to the UR holders (year ended December 31, 2013 - $78,668, nine months ended September 30, 2013 - $78,668).

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

	Nine Months Ended September 30, 2014	Year Ended December 31, 2013	Nine Months Ended September 30, 2013
Balance, beginning of period	997,000	493,000	493,000
Issued	-	649,000	350,000
Forfeited	-	(145,000)	(145,000)
Balance, end of period	997,000	997,000	698,000
Number of unit rights vested	**380,339**	152,670	147,670

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

	September 30, 2014	December 31, 2013	September 30, 2013
Fair value at the balance sheet date	$ 1.19	$ 3.62	$ 4.29
Volatility	28%	32%	32%
Life of URs	8.4 years	9.2 years	9.1 years
Risk-free interest rate	2.17%	2.70%	2.66%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Effective January 1, 2014, the expected unit price volatility was calculated using the trading history of the Trust's units from November 24, 2010 to September 30, 2014. Prior to January 1, 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 September 30, 2014**	Three Months Ended September 30, 2013	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013
Interest expense on debt	284	522	1,950	1,337
Amortization of deferred financing costs	72	64	312	180
Standby and bank fees	41	17	52	46
Accretion of decommissioning provision	15	17	62	42
Finance expense	**$ 412**	$ 620	**$ 2,376**	$ 1,605

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 September 30, 2014**	Three Months Ended September 30, 2013	**Nine Months Ended September 30, 2014**	Nine Months Ended September 30, 2013
Earnings (Loss) before taxation		$ 8,104	$ (3,241)	$ (12,836)	$ 4,758
Expected tax rate		35%	35%	35%	35%
Expected income tax provision		2,836	(1,134)	(4,493)	1,665
Decrease (Increase) resulting from:					
Non-deductible items – permanent differences					
Administrative expenses of the Trust	35%	168	247	416	685
Unit-based compensation	35%	(739)	1,380	(1,710)	1,868
Foreign exchange gain (loss), net	35%	(799)	-	(630)	-
Changes in temporary differences for which no amounts are recognized	35%	21	892	10,641	(1)
Items deductible at the subsidiary level:					
Interest on internal debt of subsidiary	35%	(1,394)	(1,393)	(4,136)	(4,135)
Other	35%	(93)	8	(88)	(82)
Total income tax expense	35%	**$ -**	$ -	**$ -**	$ -

Deferred tax assets and liabilities:

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

$ 000's	**September 30, 2014**	December 31, 2013
Deferred tax liabilities:		
Oil and gas properties in excess of tax value	$ 12,983	$ 21,440
Exploration and evaluation assets	-	-
	12,983	21,440
Less deferred tax assets:		
Non-capital losses – US based	(28,971)	(26,841)
Net deferred tax liability (asset)	(15,988)	(5,401)
Unrecognized deferred tax asset	15,988	5,401
Net deferred tax liability (asset)	**$ -**	$ -

9. Earnings (Loss) per unit

$ 000's		**Three Months Ended September 30, 2014**		Three Months Ended September 30, 2013		**Nine Months Ended September 30, 2014**		Nine Months Ended September 30, 2013
Earnings (loss) attributable to unitholders - basic	$	8,104	$	(3,241)	$	(12,836)	$	4,758
Earnings (loss) attributable to unitholders - diluted	$	6,601	$	(3,241)	$	(13,111)	$	4,758
Weighted average number of units outstanding - basic		33,878		31,004		33,265		30,282
Weighted average number of units outstanding - diluted		37,479		31,004		36,755		30,282
Earnings (loss) per unit - basic	**$**	0.24	$	(0.10)	$	(0.39)	$	0.16
Earnings (loss) per unit - diluted	**$**	0.18	$	(0.10)	$	(0.44)	$	0.16

Included in the diluted number of units outstanding for the three and nine months ended September 30, 2014 is the effect of 3,601,943 and 3,490,118 units issuable, respectively, under the 3,445,084 options outstanding under the unit option plan.

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		46,599		572		(539)		46,632
Disposals		(176,766)		-		(1,446)		(178,212)
At September 30, 2014	**$**	**262,237**	**$**	**7,678**	**$**	**959**	**$**	**270,874**
Accumulated depreciation and impairment								
At December 31, 2013	$	(73,818)	$	(3,999)	$	(288)	$	(78,105)
Depreciation		(31,979)		(1,252)		(62)		(33,293)
Disposals		23,549		-		-		23,549
Impairment		(20,552)		-		-		(20,552)
At September 30, 2014	**$**	**(102,800)**	**$**	**(5,251)**	**$**	**(350)**	**$**	**(108,401)**
Net book value								
At December 31, 2013	$	318,586	$	3,107	$	2,656	$	324,349
Net change for the period		(159,149)		(680)		(2,047)		(161,876)
At September 30, 2014	**$**	**159,437**	**$**	**2,427**	**$**	**609**	**$**	**162,473**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $US 10,188,500 (December 31, 2013 - $101,436,200) were included in the depletion calculation.

Impairment of oil and gas properties

An impairment of $20.6 million ($US 18.3 million) was recognized in the previous quarter on the Trust's oil and gas assets in relation to the Permian cost generating unit ("CGU"). The recoverable amount of the CGU was calculated based on the greater of its value in use and its fair value less costs to sell. To determine fair value less costs to sell, the Trust considered recent transactions within the industry, long-term views of commodity prices, externally evaluated reserve volumes and discount rates specific to the CGU. The impairment specifically related to the sale of the Permian Basin assets as the disposition proceeds were less than the book value of the assets.

11. Distributions payable

$ 000's		September 30, 2014		December 31, 2013
Beginning balance	$	2,813	$	2,570
Distributions declared		26,365		32,434
Distributions paid		(26,132)		(32,191)
Fair value of units issued under the DRIP		20		-
Outstanding distributions declared and payable	**$**	**3,066**	$	2,813

Distributions are declared and paid monthly. The outstanding balance at September 30, 2014 represents the distribution declared September 15, 2014 and paid October 23, 2014 plus the fair value recognition of the units issued under the Distribution Reinvestment Plan ("DRIP"). The outstanding balance at December 31, 2013 represents the distributions declared on December 16, 2013 and paid on January 23, 2014.

Effective September 12, 2014, the Trust suspended the Premium Distribution™ component of its DRIP and amended the DRIP to reduce the market discount that the Trust's units can be acquired for under the regular distribution reinvestment component from 5% to 2%.

12. Debt

As at September 30, 2014, no amounts are outstanding under the credit facility.

Total interest paid on debt for the nine month period ended September 30, 2014 was $2.0 million at an average interest rate of 5.0%. Concurrent with the internal reorganization on June 16, 2014, the Trust's credit facility was transferred from Eagle Energy Commercial Trust, as borrower, to Eagle Hydrocarbons Inc., as borrower. The Trust and its other subsidiaries and affiliates remained as guarantors under the credit agreement. See note 1 "Reporting entity/Structure of the Trust".

Following the sale of the Trust's working interest in its oil and natural gas properties in the Permian Basin on August 29, 2014, the Trust retired its outstanding advances under the existing credit facility. See note 4 "Disposition and Acquisition".

As a result of the Trust's October 1, 2014 semi-annual redetermination, the borrowing base was redetermined to $61.6 million ($US 55 million) after giving effect to the disposition of the Permian Basin assets. The credit facility has a maturity date of May 27, 2016 and is subject to semi-annual redetermination by the Trust's lenders. The next date for the redetermination is April 1, 2015.

At September 30, 2014, there were no covenant violations. Details of the Trust's credit facility are as follows:

$000's		$US		$CA
Revolving		55,000		61,600
Total authorized		55,000		61,600
Less:				
Long-term debt		-		-
Available	**$**	**55,000**	**$**	**61,600**

The exchange rate in effect at September 30, 2014 was $US 1 equal to $CA 1.12.

At December 31, 2013, details of the Trust's credit facility were 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.

13. Decommissioning liability

$000's		September 30, 2014		December 31, 2013
Beginning balance	$	3,036	$	1,744
Acquisition		92		672
Additions		274		191
Changes in estimates		163		315
Disposition		(1,224)		-
Abandonment expenditures		-		(9)
Accretion (unwinding of discount)		62		61
Effects of exchange rate		162		62
Ending balance	**$**	**2,565**	$	3,036

The decommissioning provision reflects the present value of internal estimates of future decommissioning costs of the Trust's net ownership position in oil and gas wells and related facilities at the relevant balance sheet date determined using local pricing conditions and requirements. The Trust estimates the total undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $3.9 million, which would be incurred over the lives of the assets, with the majority of costs to be incurred between 2017 and 2054. 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 assuming a 2% inflation rate), and discounted using a risk-free discount rate of 2% at September 30, 2014 for the Salt Flat properties (September 30, 2013 – 3%) and 3% for the Hardeman properties (September 30, 2013 - n/a).

14. Trust capital

Trust units outstanding	Nine Months Ended September 30, 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	2,672		16,649	2,775		20,173
Fair value adjustment	-		2,361	-		-
Units released from escrow	-		-	105		859
Trust Unit issuance costs	-		(37)	-		(111)
Ending balance	**34,821**	**$**	**316,420**	32,149	$	297,447

For the nine months ended September 30, 2014, the Trust incurred $37,099 (December 31, 2013 - $111,434) of unit issuance costs.

15. Accumulated cash distributions

$ 000's		September 30, 2014		December 31, 2013
Beginning balance	$	80,454	$	48,020
Accumulated cash distributions		26,365		32,434
Fair market value of units issued under the DRIP		2,381		-
Total accumulated cash distributions	**$**	**109,200**	$	80,454

In accordance with IFRS 13, at September 30, 2014, the Trust recorded a non-cash fair value adjustment of $2.3 million for units issued under the DRIP.

16. 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 40 months and approximately $1.6 million remaining at September 30, 2014.

Operating lease commitment – office lease in Houston, Texas

The Trust entered into a lease in Houston 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 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 39 months and approximately $US 0.9 million remaining at September 30, 2014. In $CA the remaining future minimum lease payments approximate $1.1 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.12.

17. Subsequent event

The Trust will be holding a Special Meeting of unitholders on November 24, 2014 to vote on a special resolution to amend the investment restrictions in Eagle's Trust indenture to permit the acquisition of Canadian energy assets. The record date for the Special Meeting is October 20, 2014.