VISION GROWTH INCOME

2013 Financial Report

EAGLE ENERGY™
TRUST

EAGLE ENERGY TRUST

Management's Discussion and Analysis

March 20, 2014

This Management's Discussion and Analysis ("**MD&A**") of financial condition and results of operations for Eagle Energy Trust (the "**Trust**"), dated March 20, 2014, should be read in conjunction with the Trust's audited consolidated financial statements and accompanying notes for the year ended December 31, 2013 and the Trust's Annual Information Form, which are available online at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

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

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

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.

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 are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that "field netback" and "funds flow from operations" provide useful information to investors and management since such measures reflect the quality of production, the level of profitability, the ability to drive growth through the funding of future capital expenditures and the sustainability of distributions to unitholders. Funds flow from operations is calculated before changes in non-cash working capital and abandonment expenditures. See the "Non-IFRS financial measures" section of this MD&A for a reconciliation of funds flow from operations and field netback to income for the period, the most directly comparable measure in the Trust's audited annual consolidated financial statements. Other financial data has been prepared in accordance with IFRS.

Overview of the Trust

The Trust is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The Trust's activities are restricted to owning property (other than real property or interests in real property), and it does not carry on business. The Trust's strategy is to invest in operating subsidiaries that will acquire onshore petroleum reserves and production with unexploited low risk development potential, located in certain regions of the U.S., and to pay out a portion of available cash to unitholders of the Trust on a monthly basis. The Trust provides investors with a publicly traded, petroleum focused, distribution producing investment, with favourable tax treatment relative to taxable Canadian corporations.

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

After the closing, Eagle also acquired all of another party's 1% interest in the same properties. On April 22, 2013, the Trust acquired the remaining 7.5% of the seller's interest in the Permian properties. On November 25, 2013, the Trust acquired an approximate 90% working interest in certain producing properties in Hardeman County, Texas.

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 year ended December 31, 2013

- Reported a 16% year-over-year increase in working interest sales volumes, to average 3,004 barrels of oil equivalent per day ("boe/d") (82% oil, 10% natural gas liquids ("NGLs"), 8% natural gas).
- Achieved a 12% year-over-year reduction in per boe operating expenses from $14.48 to $12.73.
- Generated a 10% year-over-year increase in field netbacks, to average $52.23 per boe. Eagle realized an average oil price of $102.93 per barrel during this period, based on the WTI benchmark average for the year of $US 97.98.
- Delivered a 25% year-over-year increase in funds flow from operations to $44.3 million ($40.38 per boe or $1.44 per unit).
- Added a third core area in November 2013 by acquiring 7,920 (7,935 net) undeveloped acres and operated properties producing 300 boe per day (97% oil) in Hardeman County, Texas for cash consideration of $27.1 million.
- Continued to manage Eagle in a financially prudent manner, with 2013 year-end debt to trailing cash flow of 1.7x (1.5x if the December 2013 cash flow from the November 2013 Hardeman acquisition is annualized).
- Created a 14% year-over-year increase in proved developed producing reserves both in net present value discounted at 10% ("**PV10**") and volume, which was essentially level on a per-unit basis.
- Achieved a 19% year-over-year increase in value of total proved reserves (PV10) and, a 3% increase in volumes. Total proved reserves were essentially level on a per-unit basis.
- Maintained 2013 unitholder distributions steady at $1.05 per unit ($0.0875 per unit per month).

Acquisition in early 2014

Subsequent to year end, 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 a net purchase price of $US 4.7 million. Through this small, tuck-in acquisition, Eagle acquired interests in 13 (5.4 net) producing wells. The sellers' working interest production at the date of acquisition was approximately 130 boe per day for a purchase price metric of $US 36,000 per flowing boe/d. The Trust used an advance under its credit facility to fund the acquisition.

For 2014, the Trust has chosen to keep its $US 28.0 million capital budget unchanged, and has reduced its planned drilling program by the amount of this $US 4.7 million acquisition. With the incremental production from this acquisition replacing the production from those wells that were removed from the drilling program, 2014 guidance for average working interest production, operating costs and cash flow remain unchanged. See the "2014 Outlook" section of this MD&A.

Management's commentary on achievement of 2013 guidance

The following shows how Eagle's 2013 results performed compared to its latest published 2013 guidance:

- Average working interest sales volumes of 3,004 boe/d was in the mid-range of the 2,900 to 3,100 boe/d guidance. With January 2014 average working interest production of approximately 3,000 boe/d, Eagle is well positioned to achieve 2014 production targets of 3,250 to 3,450 boe/d.
- Full year average operating costs were $12.73 per boe, compared to $12.00 per boe operating cost guidance.
- Full year funds flow from operations of $44.3 million, which was 98% of guidance.
- Full year capital expenditures, excluding acquisitions, were $US 29.3 million and in line with guidance at $US 29.2 million.
- 2013 year-end debt to trailing cash flow ratio of approximately 1.7x includes the late November 2013 Hardeman Acquisition for $27.1 million, which, if removed from debt, results in year-end debt to trailing cash flow of 1.1x, approximating guidance of 1.03x.

- Full year basic payout ratio of 74% (derived by dividing unitholder distributions into funds flow from operations) compared to guidance of 72%.

Operations update

With January 2014 average working interest production of approximately 3,000 boe/d, Eagle is well positioned to achieve full year 2014 production targets of 3,250 to 3,450 boe/d and poised to add additional production and reserves with the start of its capital program. As was demonstrated in 2013, Eagle will continue to focus on operational efficiencies during 2014 that lead to lower operating expenses.

At its newly acquired Hardeman property, Eagle has implemented enhancements that have resulted in production gains and plans to lower operating expenses by drilling saltwater disposal wells and using lease gas as fuel.

At its Salt Flat properties, two new wells have been drilled and completed, with plans to install horizontal pumps in certain existing wells to increase oil production. Eagle also plans to conduct a 3-D seismic program once the necessary permits are obtained. The resulting seismic data is expected to delineate the geologic complexity of the field, optimize future drill locations and potentially identify lower zones to recover bypassed oil that is not being drained by current wellbores.

At its Permian properties, Eagle's plans are to drill new wells and recomplete multiple new zones to obtain additional production from existing wellbores. To date, the first well of the recompletion program has met expectations and is on track. The new wells will be drilled in sequence with the first one commencing in March 2014.

Management's commentary on reserves

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

During 2013, Eagle closed two acquisitions, adding 2.2 million boe at a total proved plus probable acquisition cost (including future development costs) of $17.28 per boe.

Proved reserves

Proved reserves are critical to the sustainability of the Trust's cash flow and distribution payments. In 2013, Eagle added 1.9 million boe of proved reserves through acquisitions and 0.7 million boe through drilling. These proved reserves additions were offset by production and technical revisions of 2.3 million boe.

Probable reserves

The Trust's business model is to expect at best a moderate increase in proved plus probable reserves bookings, without new acquisitions. On its existing Salt Flat properties, Eagle did not anticipate significant probable reserve additions as the Salt Flat property has transitioned from growth mode to harvest mode, meaning less than half of the property's cash flow needs to be reinvested to replace declines.

This year, Eagle consolidated its external reserves evaluation into its existing US-based reserves evaluation firm in order to gain the greatest access to local Permian Basin expertise and data. Based on the most current data from the performance of Eagle's wells over time, that firm has chosen to revise Eagle's reserves estimates in both Salt Flat and Permian properties.

Eagle expects the emerging horizontal play on its Permian property to add future reserves, although it is too early for Eagle to book reserves estimates for this play. Eagle continues to monitor Permian horizontal drilling activity in the area while the play is de-risked by other operators. Eagle believes a longer production history for these wells will ultimately allow reserves to be booked that are representative of the potential of these wells. For these reasons, Eagle elected not to include any locations or value for potential horizontal wells in its 2013 reserves evaluation.

Eagle achieved the following for its 2013 reserves:

- Maintained a corporate reserve life index of approximately 12 years,
- Increased by 19% the year-over-year value of total proved reserves,

- Increased by 14% the year-over-year value and volume of proved developed producing reserves.

Eagle continues to manage its operations in a financially prudent manner, preserve sufficient liquidity, and maintain a strong balance sheet. No balance sheet impairment provision was recognized on its oil and gas properties for 2013, underpinning Management's view that the fair value of its portfolio of properties has not changed.

2014 Outlook

This outlook section is intended to provide unitholders with information about Eagle's expectations as at the date hereof for production and capital expenditures for 2014. Readers are cautioned that the information may not be appropriate for any other purpose. This information constitutes forward-looking information. Readers should note the assumptions, risks and discussions under "Note about forward-looking statements" at the end of this MD&A.

On December 17, 2013, the Board of Directors approved a 2014 capital budget of $US 28.0 million. Of this amount, $US 3.8 million will be directed towards land acquisition and seismic evaluation of future opportunities in Eagle's areas of operations, with the remaining $US 24.2 million base investment used to replace declines and grow 2014 annual working interest production and funds flow by approximately 10% over 2013.

As a result of its February 2014 tuck-in acquisition for $US 4.7 million in Hardeman County, the Trust has chosen to keep its $US 28.0 million capital budget unchanged and has reduced its planned drilling program by the amount of this $US 4.7 million acquisition. With the incremental production from this acquisition replacing the production from those wells that were removed from the drilling program, 2014 guidance for average working interest production, operating costs and cash flow remain unchanged.

For 2014, Eagle's budget continues to focus on asset development in Texas and to continue to move its assets in the Permian and Hardeman areas towards the sustainability phase. It also includes capital for the newly acquired Hardeman properties to define future development potential.

With this 2014 capital budget, Eagle intends to execute a 7 (6.2 net) well drilling program on its Salt Flat, Permian and Hardeman properties as well as embarking on recompletions, facilities upgrades and debottlenecking across its portfolio. In addition, a portion of the capital investment will be deployed to purchase land and evaluate seismic opportunities.

Eagle anticipates that its average 2014 working interest production will be in the range of 3,250 to 3,450 boe/d (up 10% year-over-year), consisting of 85% oil, 9% NGLs and 6% gas.

Operating costs per boe (inclusive of transportation) in 2014 are expected to average from $12.50 to $14.50 per boe, resulting in field netbacks of approximately $52.00 per boe.

Funds flow from operations in 2014 is expected to be approximately $49.1 million using the following assumptions:

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

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

2014 Capital budget

The Board of Directors has approved a 2014 capital budget of $US 28 million, consisting of the following drilling plans:

- Salt Flat properties:
  - 4 (3.2 net) horizontal oil wells
  - Land, seismic, other projects

- Permian properties:
  - 2 (2.0 net) vertical wells
  - 10 to 15 recompletions, capital workovers and other projects
- Hardeman properties:
  - 1 (1.0 net) vertical wells
  - 1 to 3 recompletions, capital workovers, seismic and other projects

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

Calculations and commentary regarding the sustainability of Eagle's distributions

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

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

Notes:

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

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

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

(2) Approximately $US 3.75 million of the 2014 capital budget will be directed towards land and seismic evaluation of opportunities in Eagle's areas of operation ("E" capital), and is excluded from this calculation.

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

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

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

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

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

Underlying asset quality benchmarks

Eagle's underlying asset base has the following inherent attributes:

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

Notes:

(1) Includes transportation.

(2) Directly relates to producer's ability to generate free cash flow. Assuming average operating costs (inclusive of transportation) of $13.50 per boe.

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

2014 Sensitivities

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

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

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

Sensitivity of corporate payout ratio to commodity price and production

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

Sensitivity of basic payout ratio to commodity price and production

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

Assumptions:

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

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

(3) Field operating costs (including transportation) of $13.50 per boe.

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

Sensitivities

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

	Quarterly impact on →	**Funds flow from operations ($000's)**	**Funds flow from operations / unit**
Gas price[2]	+ USD $0.10/Mcf Henry HUB	8	0.00
Oil price [2]	+ USD $1.00/bbl WTI	205	0.01
Gas production	+1000 Mcf/d	181	0.01
Oil production	+100 bbls/d	586	0.02
Currency [2]	+CDN weaken by $0.01	(179)	(0.01)
Interest Rate	+1%	(171)	(0.01)

Notes:

(1) Per unit figures are based on 30,649,550 weighted average basic units outstanding for the year ended December 31, 2013.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate equal to 2013 average working interest sales volumes of 3,004 boe/d.

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Selected annual information

The following table shows selected information for the Trust's fiscal year ended December 31, 2013, December 31, 2012 and December 31, 2011.

Year ended December 31	**2013**	2012	2011
($000's except per unit amounts and production)			
Sales volumes – boe/d	3,004	2,596	1,376
Revenue, net of royalties	71,217	58,724	31,771
Field netback	57,260	44,962	25,150
Funds flow from operations	44,271	35,298	19,853
per unit – basic	1.44	1.43	1.11
per unit - diluted	1.44	1.33	1.11
Income (loss)	4,914	6,117	(1,213)
per unit – basic	0.16	0.25	(0.07)
per unit - diluted	0.16	0.24	(0.07)
Current assets	9,889	14,464	13,386
Current liabilities	30,461	17,512	16,557
Total assets	335,679	284,802	158,885
Total non-current liabilities	70,521	42,111	502
Unitholders' equity	234,697	225,179	141,826
Distributions declared	32,434	26,816	19,287
per issued unit	1.05	1.05	1.05
Units outstanding for accounting purposes	32,149	29,269 (2)	18,544 (1)
Units issued	32,149	29,374	18,931

Notes:

(1) Units outstanding for accounting purposes exclude 387,000 units issued due to the performance conditions that had to be met to enable such units to be released from escrow.

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

Results of operations

Production

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	%	**Year Ended December 31, 2013**	Year Ended December 31, 2012	%
Oil (bbl/d)	2,452	2,575	(5)	2,484	2,361	5
Natural gas (Mcf/d)	1,413	1,069	32	1,360	618	120
Natural gas liquids (bbl/d)	307	233	32	293	132	122
Oil equivalent sales volumes (boe/d @ 6:1)	**2,994**	2,986	-	**3,004**	2,596	16

Working interest sales volumes for the year ended December 31, 2013 averaged 3,004 boe/d (92% oil and natural gas liquids, 8% natural gas), which is 16% above the prior year. Fourth quarter oil volumes were slightly below third quarter 2013 levels due to non-recurring weather related and non-owned infrastructure problems. The year-over-year increase is due to more effective base production management, acquisitions and drilling activity. See “Liquidity and capital resources - Capital expenditures, Acquisitions and Activity summary”.

Revenue ($000’s)		**Three Months Ended December 31, 2013**		Three Months Ended December 31, 2012	**%**		**Year Ended December 31, 2013**		**Year Ended December 31, 2012**	%
Oil	$	23,008	$	21,913	5	$	93,190	$	78,868	18
Natural gas		459		257	79		1,784		590	202
Natural gas liquids		1,029		703	46		3,793		1,672	127
Sales before royalties	**$**	**24,495**	$	22,873	7	**$**	**98,767**	$	81,130	22

Realized prices										
Oil ($/bbl)	$	102.01	$	92.51	10	$	102.93	$	91.27	13
Natural gas ($/Mcf)		3.53		2.61	35		3.60		2.61	38
Natural gas liquids ($/bbl)		36.36		32.80	11		35.44		34.50	3
Sales before royalties ($/boe)		88.92		83.27	7		90.08		85.37	6
Royalties ($/boe)		(24.55)		(23.13)	6		(25.13)		(23.58)	7
Sales net of royalties ($/boe)	**$**	**64.37**	$	60.14	7	**$**	**64.95**	$	61.79	5

Benchmark prices										
Oil – WTI ($US/bbl)	**$**	**97.46**	$	88.30	10	**$**	**97.98**	$	94.21	4
Natural gas – Henry HUB ($US/Mcf)	**$**	**3.86**	$	3.40	14	**$**	**3.68**	$	2.79	32

The Trust’s quarterly revenue is 94% derived from oil, 4% from natural gas liquids, and 2% from natural gas. Realized oil prices of $US 99.04 were at a premium to benchmark $US WTI. Natural gas liquids prices were approximately 35% of $US WTI.

There is a quality differential between the benchmark WTI price and the $US price realized by the Trust. Eagle enters into field marketing contracts to obtain the most favourable pricing. Management monitors pricing regularly and endeavours to maximize realized sales prices while minimizing counterparty risk. The Trust has acquired US properties which are close to markets and, in so doing, realizes premium sales prices compared to producers of Canadian oil.

For the Salt Flat properties, a field marketing contract was in place for January and February 2014 which used Louisiana Light Sweet (“LLS”) as a reference price instead of WTI. This contract held all other field pricing adjustments fixed, but let the LLS-WTI differential float. By way of example, this contract resulted in Eagle realizing an oil price of $US 104.42 per barrel in February, which was a $US 3.96 premium to the benchmark WTI price of $US 100.46. As of March 2014, the contract rolled to a 30 day evergreen contract in which all other field pricing adjustments (except for a fixed $US 7.00 per barrel marketing fee) and the LLS-WTI differential float.

For the Permian properties, a field marketing contract was in place for January and February 2014 which used WTI as a reference price. This contract held all other field pricing adjustments fixed. By way of example, this contract resulted in Eagle realizing an oil price of $US 101.29 per barrel in February, which was a $US 0.83 premium to WTI of $US 100.46. As of March 2014, the contract rolled to a 30 day evergreen contract in which all other field pricing adjustments float (except for a fixed $US 2.15 per barrel marketing fee).

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

The benchmark WTI price increased 10% from the prior year’s comparative quarter, and 4% on a year-over-year basis. Canadian dollar realized prices increased by a commensurate amount from the prior years’ comparative quarter, and increased 13% on a year-over-year basis due to the weakening Canadian dollar. The above prices do not include realized gains or losses from financial commodity contracts, which amounted to a realized gain of $0.2 million ($0.66/boe) for the three months ended December 31, 2013 and a realized loss of $0.5 million ($0.48/boe) for the year. See *Realized and unrealized risk management gain/loss.*

The overall royalty rate of approximately 28% was consistent with prior periods for both the three months and year-ended December 31, 2013.

Operating costs

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	%	Year Ended December 31, 2013	Year Ended December 31, 2012	%
	$/boe	$/boe		**$/boe**	$/boe	
Transportation	2.34	2.16	8	2.32	2.11	10
Other operating costs	14.45	11.31	28	10.41	12.37	(16)
	16.79	13.47	25	**12.73**	14.48	(12)

The 25% increase in quarter-over-quarter operating costs is due primarily to non-recurring well workover costs in both the Permian and Salt Flat properties. Improved operational efficiencies (reducing salt water disposal costs, resizing submersible pumps and negotiating lower power contracts) resulted in a 12% year-over-year reduction in per boe operating costs and afforded the Trust the ability to guide to only a modest increase in operating costs of $12.50 to $14.50 per boe for 2014.

Depreciation, depletion and amortization

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	%	Year Ended December 31, 2013	Year Ended December 31, 2012	%
	$/boe	$/boe		**$/boe**	$/boe	
Depreciation, depletion and amortization	**31.75**	50.41	(37)	**28.29**	32.28	(12)

The depletion, depreciation, and amortization provision for the three months and year-ended December 31, 2013 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 evaluator. On a quarter-over-quarter basis, the 2013 charge per boe is significantly below that of the comparable 2012 quarter because the latter incorporated an impairment charge.

Field netback

	Three Months Ended December 31, 2013		Three Months Ended December 31, 2012		Year Ended December 31, 2013		Year Ended December 31, 2012	
($000's)	**$**	**$/boe**	$	$/boe	**$**	**$/boe**	$	$/boe
Sales before royalties	24,495	88.92	22,873	83.27	98,767	90.08	81,130	85.37
Royalties	(6,762)	(24.55)	(6,354)	(23.13)	(27,550)	(25.13)	(22,406)	(23.58)
Other operating costs	(3,981)	(14.45)	(3,107)	(11.31)	(11,412)	(10.40)	(11,753)	(12.37)
Transportation	(646)	(2.34)	(595)	(2.16)	(2,545)	(2.32)	(2,009)	(2.11)
Field netback	**$ 13,106**	**$ 47.58**	$ 12,817	$ 46.67	**$ 57,260**	**$ 52.23**	$ 44,962	$ 47.31
Sales volumes (boe/d)		**2,994**		2,986		**3,004**		2,596

During the fourth quarter, benchmark WTI averaged $US 97.46 per barrel ($US 97.98 year to date) and the Trust realized a field netback of $47.58 per barrel ($52.53 year to date). On a quarter-over-quarter basis, higher realized prices were largely offset by non-recurring well workover costs. On a year-over-year basis, stronger commodity prices, lower operating costs and a weaker Canadian dollar resulted in a 10% increase in per-boe netbacks in 2013.

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:

Oil Fixed Price	Volume	Contract Term	Price $US
NYMEX (i)	400 bbls/d	Jan 2014 to Dec 2014	$98.00
NYMEX (iii)	500 bbls/d	Jan 2014 to Dec 2014	$100.00
NYMEX (i)	500 bbls/d	Jan 2014 to Dec 2014	$91.15
NYMEX (i)	400 bbls/d	Jan 2014 to Dec 2014	$91.15
NYMEX (ii)	250 bbls/d	Jan 2014 to Dec 2014	$90.00 - $94.95
NYMEX (ii)	100 bbls/d	Jan 2014 to Dec 2014	$93.00 - $95.35

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

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	%	**Year Ended December 31, 2013**	Year Ended December 31, 2012	%
Realized gain (loss)	**$** 183	$ 506	(64)	**$** (528)	$ 483	-
Unrealized gain (loss)	97	240	(60)	(3,675)	2,709	-
Total net gain (loss)	**280**	746	(62)	**(4,203)**	3,192	-

On a year-over-year basis, the net value of the commodity price contracts has decreased. The net value of the contracts is dependent upon current and forward commodity pricing and, in the case of realized gains and losses, the price of the contract relative to the benchmark oil price at time of expiry. Although the Trust currently has no intention of unwinding the contracts that are in place, it is required to calculate and record, using a mark-to-market valuation, the fair value of the remaining term of the contracts at the end of each reporting period, hence the change in value of the unrealized portion of the commodity contracts. On a quarter-over-quarter basis, a weakening forward commodity pricing environment has caused the future value of these contracts to increase relative to September 30, 2013 thus reducing the unrealized liability position at December 31, 2013.

On January 7, 2014 the Trust entered into a contract to mitigate the effects of foreign exchange rate ($CA/$US) fluctuations on monthly distribution payments as follows: a costless collar contract from January to December 2014 for an average of $922,000 per month at a floor of $CA 1.05 and a ceiling of $CA 1.09.

Finance expense

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	%	**Year Ended December 31, 2013**	Year Ended December 31, 2012	%
Finance expense	**$** 861	$ 617	40	**$** 2,467	$ 1,330	85
Per barrel	**3.13**	2.25	39	**2.25**	1.40	61

For the three months and year-ended December 31, 2013, finance expense increased over prior comparative periods due to increased borrowing to fund acquisitions of the remaining 7.5% of the Permian properties for $8.8 million, and the Hardeman properties for $27.1 million.

As of December 31, 2013, the effective interest rate on bank debt for the period was 3.5%, which was less than the 5.3% incurred for the comparable period in 2012. During 2013, the Trust utilized advances using the LIBOR rate option which was lower than the base rate option on its borrowings.

Administrative expenses

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	%	**Year Ended December 31, 2013**	Year Ended December 31, 2012	%
Administrative expenses	**$ 3,525**	$ 2,741	29	**$ 8,998**	$ 8,078	11
Per barrel	**12.80**	9.98	28	**8.21**	8.50	(3)

Administrative expenses for the fourth quarter of 2013 included $0.2 million ($0.71/boe) of one-time transaction costs relating to the Hardeman property acquisition as well as other typical fourth quarter charges such as annual bonuses, audit and engineering charges.

Over the past year, engineering, geological field and accounting staff were added to assist with full cycle property development, acceleration of the strategic focus on potential acquisitions and management of planned activities. Staff and related employment costs accounted for 72% of annual administrative expenses.

Unit-based compensation

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	%	**Year Ended December 31, 2013**	Year Ended December 31, 2012	%
Unit-based compensation expense	**$ (287)**	$ 3,307	(91)	**$ 5,049**	$ 2,023	150

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

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

The Trust is, however, required to re-determine the fair value of the liability each quarter relating to: (1) the restricted unit rights, (2) the options and (3) the unit rights. Any changes in fair value are recorded as an expense.

From one reporting period to the next, changes in the closing price of the units, accumulated distributions and expected future unit price volatility will increase or decrease the fair values of the unit based awards as calculated under the Black-Scholes valuation model. These fair value changes cause corresponding swings in the amount recorded in the income statement. The increase in the unit based payment liability and associated expense from December 31, 2012 to December 31, 2013 was due to (1) additional awards vesting over time, (2) additional awards being granted during that period, and (3) higher year-over-year price of the Trust's units ($8.07 per unit at December 31, 2013 compared to $7.69 per unit at December 31, 2012).

During the fourth quarter 2013, $0.2 million (three months ended December 31, 2012 - $0.1 million) was paid out in cash for amounts related to restricted unit rights and unit rights, and $1.2 million was paid for the year ended December 31, 2013 (year ended December 31, 2012 - $1.1 million). The liability that was, and continues to be, accrued from inception for these cash settled awards was reduced by such cash payments.

At December 31, 2013, all restricted unit rights have vested and each restricted unit rights holder is entitled to monthly payments that track monthly unit distributions. For the three months ended December 31, 2013, $0.2 million (December 31, 2012 - $0.1 million) was paid in cash to the restricted unit rights holders and $1.1 million was paid for the year-ended December 31, 2013 (December 31, 2012 - $1.1 million).

Impairment of oil and gas properties

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

At December 31, 2012, the Trust recognized a $6.1 million impairment on its oil and gas properties. To calculate the impairment, the fair value less costs to sell for each cash generating unit was estimated and then compared to the net book value for each cash generating unit. Since the net book value exceeded fair value, an impairment was recognized. The fair value was calculated by taking the net present value of the after tax cash flows from its oil and gas proved plus probable reserves as estimated by the third party reserve evaluators, discounted at a rate of 8%. The impairment was primarily related to technical issues during well completions at the Salt Flat properties and slightly lower forward pricing. An improvement in reserve estimates or commodity pricing could reverse any impairment charges recorded (after accounting for depletion and depreciation charges otherwise applicable).

Tax horizon

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

Summary of quarterly results

	Q4/2013	Q3/2013	Q2/2013	Q1/2013	Q4/2012	Q3/2012	Q2/2012	Q1/2012
($000's except for boe/d and per unit amounts)								
Sales volumes – boe/d	2,994	3,052	3,022	2,928	2,986	2,825	2,400	2,169
Revenue, net of royalties	17,733	19,517	17,162	16,805	16,519	15,181	13,077	13,947
per boe	64.37	69.51	62.42	63.77	60.13	58.41	59.90	70.67
Funds flow from operations	8,794	11,615	11,977	11,884	9,905	9,039	7,233	9,118
per boe	31.93	41.37	43.56	45.10	36.06	34.78	33.13	46.20
per unit – basic	0.28	0.37	0.39	0.40	0.34	0.32	0.31	0.50
per unit – diluted	0.28	0.37	0.39	0.40	0.32	0.32	0.31	0.50
Income (loss)	156	(3,241)	3,919	4,080	(403)	(1,095)	8,567	(952)
per unit – basic & diluted	0.00	(0.10)	0.13	0.14	(0.02)	(0.04)	0.37	(0.05)
Distributions declared	8,376	8,204	8,026	7,828	7,653	7,512	6,628	5,024
per issued unit	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625
Current assets	9,889	9,950	11,443	9,913	14,464	14,209	18,758	16,447
Current liabilities	30,461	20,942	19,874	11,982	17,512	23,723	28,158	20,319
Total assets	335,679	306,021	311,271	283,112	284,802	283,913	291,273	156,477
Total non-current liabilities	70,521	55,069	50,654	39,873	42,111	35,136	27,192	489
Unitholders' equity	234,697	230,010	240,743	231,257	225,179	225,055	235,923	135,669
Units outstanding for accounting purposes	32,149	31,469	30,707[1]	29,960[1]	29,269[1]	28,654[1]	27,895[1]	18,847[1]
Units issued	32,149	31,469	30,813	30,066	29,375	28,783	28,283	19,234

Note:

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

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

Sales volumes in the fourth quarter of 2013 were slightly below third quarter 2013 levels due to non-recurring weather related and non-owned infrastructure problems. Refer to the sections of this MD&A titled "Liquidity and capital resources – Capital Expenditures, Acquisitions and Activity Summary" for additional information.

Funds flow from operations decreased in the fourth quarter of 2013, when compared to the prior quarter due to weaker commodity prices, non-recurring well workover costs and additional administrative expenses typical for the fourth quarter. Generally, in times of steady or increasing prices, funds flow from operations grows as sales volumes increase, and on a per-boe basis, will decline when volumes decline. This is because certain expenses tend to be more fixed in nature, such as general and administrative expenses, and do not decrease as sales volumes decrease.

Income (loss) on a quarterly basis often does not move directionally or by the same amount as movements in funds flow from operations. This is primarily due to items of a non-cash nature that factor into the calculation of income (loss), and are required to be fair valued at each quarter end. By way of example, fourth quarter 2013 funds flow from operations decreased 24% from the third quarter while the fourth quarter loss decreased by 93%. This occurred for two reasons. First, a weakened forward commodity price environment raised the fair market valuation of Eagle's forward commodity contracts. Second, a lower year end unit price caused a lower fourth quarter expense to be recorded in the income statement upon performing a fair market valuation of future unit based payments.

Total current and non-current liabilities increased in the fourth quarter of 2013 compared to the third quarter of 2013 as a result of increased borrowing to fund the acquisition of the Hardeman property on November 25, 2013. Refer to the sections of this MD&A titled "Capital expenditures and Acquisitions" for additional discussion.

Liquidity and capital resources

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

Management's objective is to maintain an external debt to cash flow ratio not to exceed 1.5 to 1.0. This ratio may increase at certain times as a result of acquisitions. As at December 31, 2013, the Trust's ratio of ending debt to trailing cash flow was approximately 1.7 to 1.0 and includes the late November 2013 Hardeman Acquisition for $27.1 million. If the December 2013 cash flow from this 300 boe/d acquisition was annualized, the Trust would be at 1.5 times debt to cash flow.

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

Funds flow from operations

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

	Three Months Ended December 31, 2013		Three Months Ended December 31, 2012		**Year Ended December 31, 2013**		Year Ended December 31, 2012	
($000's)		**$/boe**		$/boe		**$/boe**		$/boe
Field netback	**$** 13,106	**$** 47.58	$ 12,817	$ 46.67	**$** 57,260	**$** 52.23	$ 44,962	$ 47.31
Cash settled award payments	(166)	(0.60)	(127)	(0.46)	(1,189)	(1.08)	(1,086)	(1.14)
Administrative expenses	(3,525)	(12.80)	(2,741)	(9.99)	(8,997)	(8.21)	(8,078)	(8.50)
Realized risk management gain (loss)	183	0.66	506	1.84	(528)	(0.48)	483	0.51
Finance expense	(770)	(2.79)	(517)	(1.88)	(2,154)	(1.97)	(1,167)	(1.23)
Realized foreign exchange gain (loss)(1)	(34)	(0.12)	(33)	(0.12)	(121)	(0.11)	184	0.19
Funds flow from operations	**$ 8,794**	**$ 31.93**	$ 9,905	$ 36.06	**$ 44,271**	**$ 40.38**	$ 35,298	$ 37.14

Note:

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

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

Credit facility (Revolving and Non-revolving)

As of December 31, 2013, the Trust had approximately $US 16.6 million of unused credit on its $US 80 million revolving credit facility and was fully drawn on its $US 10 million non-revolving term credit facility, both of which are held with a syndicate of Canadian chartered banks.

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

Working capital

At December 31, 2013, the Trust had a working capital deficiency, excluding the $US 10 million non-revolving term credit facility, of $10.3 million (which becomes a $1.1 million surplus when the non-cash current portion of unit-based compensation payments and current risk management liability are excluded), $67.5 million (December 31, 2012 - $40.2 million) drawn on its

$US 80 million revolving credit facility, and $10.6 million (December 31, 2012 - $nil) drawn on its $US 10 million non-revolving term credit facility.

Unitholders' equity

Other than the units released from escrow on September 14, 2013, all Trust capital issuances during 2013 were issued pursuant to the distribution reinvestment plans as detailed below.

As a result of its Premium Distribution™ and Distribution Reinvestment Plan, the Trust received proceeds resulting from the issuance of units from treasury to those unitholders who have opted to participate in the Plan. For the three months ended December 31, 2013, 680,036 units (three months ended December 31, 2012 - 591,106 units) were issued for total proceeds of $5.2 million (three months ended December 31, 2012 - $4.9 million) at an average unit price of $7.64 (three months ended December 31, 2012 - $8.39 per unit).

For the year ended December 31, 2013, 2,879,766 units (year ended December 31, 2012 - 1,763,461 units) were issued for total proceeds of $20.1 million (year ended December 31, 2012 - $16.4 million) at an average unit price of $7.30 (year-ended December 31, 2012 - $8.39).

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 fourth quarter (for the September, October, and November 2013 record dates) totalled approximately $8.3 million and totalled $32.2 million for the year.

At December 31, 2013, the Trust had issued 32,148,909 units.

As at the date of this MD&A, 32,580,320 units are issued and 3,176,750 options are outstanding.

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

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	**Year Ended December 31, 2013**	Year Ended December 31, 2012
(000's)	**$**	$	**$**	$
Income (loss) for the period	156	(403)	4,914	6,117
Cash distributions paid	(8,133)	(7,602)	(32,191)	(25,902)
Shortfall of income (loss) over cash distributions paid	**(7,977)**	(8,005)	**(27,277)**	(19,785)
Funds flow from operations[1]	8,794	9,905	44,271	35,298
Changes in working capital	(1,494)	(3,102)	(2,579)	(981)
Abandonment expenditures	-	(130)	(9)	(130)
Net cash provided by operating activities	7,300	6,673	41,683	34,187
Cash distributions paid	(8,133)	(7,602)	(32,191)	(25,902)
Excess (shortfall) of net cash provided by operating activities over cash distributions paid	**(833)**	(929)	**9,492**	8,285

Note:

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

For the three months and years ended December 31, 2013 and 2012, cash distributions paid exceeded income (loss) for the period due to non-cash items which are deducted or added in determining income (loss) for the period. Income (loss) often does not move directionally or by the same amount as movements in net cash provided by operating activities. This is primarily due to items of a non-cash nature that factor into the calculation of income (loss), and are required to be fair valued at each period end. Examples of non-cash items include depreciation, depletion and amortization, impairment, unit based compensation, and unrealized risk management losses, all of which have no impact on cash available to pay distributions.

Net cash provided by operating activities exceeded cash distributions paid by $9.5 million for the year ended December 31, 2013 (year ended December 31, 2012 - $8.3 million).

For the three months ended December 31, 2013 and 2012, cash distributions paid exceeded net cash provided by operating activities by $0.8 million and $1.0 million respectively. The Trust's Premium Distribution™ and Distribution Reinvestment Plan reduce the amount of cash required to pay distributions, as new units are issued in place of cash distributions. Refer to the "Unitholders' equity" section of this MD&A.

Capital expenditures

Capital spending during the quarter and year ended December 31, 2013 and December 31, 2012 was as follows:

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	**Year Ended December 31, 2013**	Year Ended December 31, 2012
(000's)	**$**	$	**$**	$
Exploration and evaluation[(1)]	-	120	63	303
Acquisition of Permian properties- 92.5% interest	-	-	-	115,902
Acquisition of Permian properties- 7.5 % interest	(62)	-	8,768	-
Acquisition of Hardeman properties	27,087	-	27,087	-
Intangible drilling and completions	1,017	9,628	26,198	30,032
Well equipment and facilities	388	1,030	3,856	12,848
Office furniture and fixtures	6	-	86	-
Proceeds from disposal of assets	(106)	-	(106)	-
Other	12	129	129	274
	$ 28,342	$ 10,907	**$ 66,081**	$ 159,359

Note:

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

During the fourth quarter, capital spending was minimal, with the Trust incurring $1.4 million on drilling, completions, equipment and facilities. Of this total, $0.9 million was for drilling one salt water disposal well and $0.4 million was for well completions on the Salt Flat properties and $0.1 million was for well completions on the Permian properties.

Acquisitions

On April 22, 2013, the Trust acquired the remaining 7.5% interest in its Permian properties for cash consideration of $8.8 million which includes a closing adjustment credit of approximately $0.1 million. The Trust now owns a 100% working interest in its Permian properties. 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:

$000's		
Identifiable assets acquired and liabilities assumed:		
Oil and gas properties	$	8,914
Decommissioning liabilities		(84)
	$	**8,830**

On November 25, 2013, the Trust acquired producing properties in Hardeman County, Texas (the "Hardeman Acquisition") for cash consideration of $27.1 million, which included a preliminary closing adjustment credit of $0.6 million. The seller's working interest production from the properties at the date of acquisition was approximately 300 boe per day, consisting of 97% light sweet crude (43° API) from 34 (29.9 net) producing wells. Through this acquisition, with an effective date of December 1, 2013, Eagle also acquired 7,920 gross (7,395 net) undeveloped acres. Eagle estimated the average annual decline rate of the Hardeman County properties to be 12%. In addition, upon successful closing of this acquisition, Eagle's lenders approved a further increase in Eagle's credit facility to $US 90.0 million consisting of a $US 80.0 million revolving facility and a new one year non-revolving term credit facility of $US 10.0 million. The Trust used an advance under this credit facility to fund the acquisition. Had this transaction closed on January 1, 2013, the additional revenue, net of royalties would have been approximately $US 5.8 million for the period ended December 31, 2013. The net income effect is not determinable.

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:

$000's		
Identifiable assets acquired and liabilities assumed:		
Oil and gas properties	$	27,675
Decommissioning liabilities		(588)
	$	**27,087**

Activity summary

Wells Drilled	**Three Months Ended December 31, 2013**		Three Months Ended December 31, 2012		**Year Ended December 31, 2013**		Year Ended September 30, 2012	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Salt Flat	1	1.0	4	3.2	7	6.2	19	15.2
Permian	-	-	5	4.6	5	5.0	9	8.2
Hardeman	-	-	-	-	-	-	-	-
Total	**1**	**1.0**	9	7.8	**12**	**11.2**	28	23.4

Wells Brought On-stream	**Three Months Ended December 31, 2013**		Three Months Ended December 31, 2012		**Year Ended December 31, 2013**		Year Ended September 30, 2012	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Salt Flat	-	-	5	4.0	6	5.2	19	15.2
Permian	-	-	4	3.7	6	6.0	8	7.4
Hardeman	-	-	-	-	-	-	-	-
Total	**-**	**-**	9	7.7	**12**	**11.2**	27	22.6

The Trust's 2013 drilling program was successfully completed in the third quarter of 2013 with the exception of one salt water disposal well drilled in Salt Flat during the fourth quarter.

Year-end reserves information

An independent evaluation of the Trust's reserves at December 31, 2013 was conducted by Netherland, Sewell & Associates, Inc. The reserves evaluation report is effective December 31, 2013 and was prepared in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

2013 Year-end reserves report - highlights

- A 14% year-over-year increase in value (PV10) and volume of proved developed producing reserves.
- 77% of the proved developed producing reserves are light oil, 13% are natural gas liquids and 10% are natural gas.
- A 19% year-over-year increase in value (PV10) of total proved reserves and, a 3% increase in volumes.
- Closed two acquisitions, adding approximately 2.2 million boe of proved plus probable reserves and 400 boe/d of production at an acquisition cost, including future development costs, of approximately $17.28/boe.
- Total proved plus probable reserves of approximately 14.3 million boe (76% proved, 36% proved producing).
- Proved plus probable reserve life index of 11.7 years based on the mid-point of 2014 average working interest production guidance.

The following tables summarize the independent reserves estimates and values as at December 31, 2013 of Eagle's reserves:

Summary of Reserves

	Company Gross[(1)(2)]				
Reserves Category	Crude Oil	Natural Gas Liquids	Natural Gas	**Total Oil Equivalent 2013**	Total Oil Equivalent 2012
	(Mbbls)	(Mbbls)	(MMcf)	**(Mboe)**	(Mboe)
Proved					
Developed Producing	3,997	686	3,035	5,189	4,558
Developed Non-Producing	1,012	200	830	1,350	784
Undeveloped	3,218	689	2,855	4,383	5,270
Total Proved	8,226	1,576	6,720	**10,922**	10,612
Probable	2,826	343	1,428	**3,407**	5,023
Total Proved Plus Probable	11,052	1,919	8,148	**14,329**	15,635

Notes:

(1) Company gross reserves are Eagle's total working interest share before the deduction of any royalties and without including any of Eagle's royalty interests. Eagle holds non-material overriding royalty interests in certain of its assets in the Permian properties.

(2) Totals may not add due to rounding.

Summary of Net Present Value of Future Net Revenue of Reserves

	Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year) [(1)(2)]				
Reserves Category	0%	5%	10%	15%	20%
	($US 000's)	($US 000's)	($US 000's)	($US 000's)	($US 000's)
Proved					
Developed Producing	207,731	158,064	131,949	115,487	103,925
Developed Non-Producing	41,547	31,963	25,632	21,175	17,877
Undeveloped	102,916	62,620	40,879	27,963	19,703
Total Proved	352,194	252,646	198,459	164,626	141,505
Probable	135,719	94,601	71,212	56,366	46,187
Total Proved Plus Probable	487,913	347,248	269,672	220,992	187,692

Notes:

(1) Estimates of after-tax future net revenue are not presented because it is expected that neither Eagle nor the Trust will be subject to taxes in Canada.

(2) Based on GLJ Petroleum Consultants Ltd.'s January 1, 2014 forecast prices.

(3) It should not be assumed that the present values of estimated future net revenue shown above are representative of the fair market value of the reserves. There is no assurance that such price and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of crude oil reserves provided in this MD&A are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil reserves may be greater than or less than the estimates provided.

At a 10% discount factor, proved producing reserves comprise 49% (2012 – 44%) of the total proved and probable value. Total proved reserves account for 74% (2012 – 63%) of the proved plus probable value.

Capital efficiency table

During 2013, Eagle's capital expenditures, including acquisition capital, resulted in capital efficiency statistics as shown in the following table. Note that statistics which cannot be meaningfully calculated are shown as a dashed line:

	2013		2012	
	Proved	**Proved plus Probable**	Proved	Proved plus Probable
Exploration and Development expenditures ($000) (1)	30,226	30,226	43,183	43,183
Acquisitions ($000) (2)	35,855	35,855	115,902	115,902
Change in future development capital ($000)				
Exploration and development	(18,567)	(17,350)	(16,968)	(32,617)
Acquisitions	1,228	1,308	95,113	95,113
Reserves additions (Mboes)				
Exploration and development	(504)	(2,358)	(230)	(1,319)
Acquisitions	1,913	2,151	8,103	10,226
	1,409	(207)	7,873	8,907
Acquisition costs ($/boe) (1)				
Including change in FDC (3)	19.38	17.28	26.04	20.63
Excluding change in FDC	18.74	16.67	14.30	11.33
Finding, development & acquisitions costs ($/boe) (1)(4)				
Including change in FDC (3)	34.59	-	30.13	24.88
Excluding change in FDC	46.90	-	20.20	17.86
Recycle ratio (4)	1.5x	-	1.6x	1.9x
Reserves replacement (5)	128%	-	832%	942%
Reserve life index (yrs) (6)	8.9	11.7	9.7	14.3

Notes:

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

(2) Acquisition costs related to the 2013 asset acquisitions in the Permian and Hardeman properties.

(3) Eagle calculates finding, development and acquisition ("FD&A") costs which incorporate both the costs and associated reserve additions related to acquisitions during the year. Since acquisitions have a significant impact on Eagle's annual reserve replacement costs, Eagle believes that FD&A costs provide a more meaningful portrayal of Eagle's cost structure.

(4) The recycle ratio is calculated using Eagle's 2013 field netback of $52.23 per boe (2012 - $47.31 per boe) (see the Field Netback section of this MD&A) and dividing that number by the FD&A costs per boe.

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

(6) The 2013 reserve life index calculation is based on the mid-point of Eagle's 2014 average working interest production guidance of 3,350 boe/d and the 2012 reserve life index calculation was based on 3,000 boe/d.

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)	3,040	605	1,558	877
Total contractual obligations	**$ 3,040**	**$ 605**	**$ 1,558**	**$ 877**

Notes:

(1) Calgary, Alberta office lease: On January 1, 2013, the Trust entered into a head-lease agreement for new office space which has a 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 leasehold improvements allowance of $0.3 million, with 49 months and $1.9 million remaining at December 31, 2013.

(2) Houston, Texas office lease: The agreement was entered into on April 1, 2011, and has a 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease agreement was extended for an additional 63 months 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 an available lease hold improvement allowance of $US 111,293 and $US 1.5 million with 48 months and $US 1.1 million remaining at December 31, 2013. 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 1.06.

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

Transactions with related parties

Key management personnel

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

Intercompany transactions

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

Critical accounting estimates and judgments

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

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

Estimation of oil and gas reserves

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

Business combinations

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

Decommissioning provision

Estimates of the amounts of provision for decommissioning recognized are based on current legal and construction requirements, technology, and price levels. As actual outflows may be different from estimates due to changes in laws, regulations, technology, prices and conditions, and can take place in the future, the carrying amounts of provisions are regularly reviewed and adjusted to take account of such changes. Because the accounting standard is not clear as to the choice of risk-free or risk-adjusted discount rate, the Trust has interpreted the accounting standard to use the risk-free discount rate for calculating the present value of the decommissioning obligation.

Impairment calculations

The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions. It is reasonably possible that the commodity price assumption may change, which may impact the estimated life of the asset and may require a material adjustment to the carrying value of assets. The Trust monitors internal and external indicators of impairment relating to its tangible and intangible assets and discount rate estimates.

Income taxes

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

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

Derivative financial instruments

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

Classification of trust units as equity

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

Contingencies

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

Unit-based compensation

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

Accounting standards and interpretations adopted:

The Trust adopted the following new and revised standards, along with any consequential amendments, effective January 1, 2013. These changes were made in accordance with the applicable transitional provisions.

- IAS 1, Presentation of Financial Statements. The Trust adopted the amendments to IAS 1 effective January 1, 2013. These amendments required the Trust to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. The Trust has reclassified comprehensive income items of the comparative period. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

- IFRS 10, Consolidated Financial Statements, replaces the guidance on control and consolidation in IAS 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation - Special Purpose Entities. The Trust assessed is consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of any of its subsidiaries.

- IFRS 11, Joint Arrangements, supersedes IAS 31, Interests in Joint Ventures, and requires joint arrangements to be classified either as joint operations or joint ventures depending on the contractual rights and obligations of each investor that jointly controls the arrangements. The Trust has classified its joint arrangements and concluded that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements.

- IFRS 13, Fair Value Measurement, provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. The Trust adopted IFRS 13 on January 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Trust to measure fair value and did not result in any measurement adjustments.

- IAS 19, Employee Benefits (amended in 2011), amends certain accounting requirements for defined benefits plans and termination benefits. These changes do not impact the Trust and it did not result in any adjustments to the Financial Statements.

- IAS 36, Impairment of assets – Disclosures, addresses the disclosure of information about the recoverable amount of impaired assets if that amount is based on fair value less costs of disposal. The amendments to IAS 36 are effective January 1, 2014. The Trust adopted the amendment in the current period and concluded that the adoption of IAS 36 did not result in any changes to the disclosure of impaired assets in 2013.

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

Risk management

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

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

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

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. The approach to managing liquidity is to ensure, as far as possible, that the Trust will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Trust's reputation. At December 31, 2013, the Trust had a working capital deficiency, excluding the non-revolving term credit facility, of approximately $10.3 million (which becomes a $1.2 million surplus when the non-cash current portion of unit-based payments and current risk management contracts are excluded), $US 63.4 million (December 31, 2012 - $US 40.5 million) drawn on its $US 80 million revolving credit facility and $US 10 million (December 31, 2012 - $nil) drawn on its $US 10 million non-revolving term credit facility. To better manage its liquidity risk, the Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil revenue each month.

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

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by various factors, including the exchange rates between the Canadian and United States dollar, but also world economic events that dictate the levels of supply and demand. The Trust enters into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. It is the policy of the Trust to not hedge more than 50% of its near-term working interest production. This percentage may increase at certain times as a result of acquisitions.

As at the date of this MD&A, the Trust has entered into contracts to mitigate the effect of commodity price fluctuations. Refer to the “Realized and unrealized risk management gain” section of this MD&A.

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

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. As at December 31, 2013, $US 63.4 million had been drawn against the $US 80 million revolving credit facility (December 31, 2012 - $US 40.5 million) and the $US 10 million non-revolving term credit facility was fully drawn (December 31, 2012 - $nil). The Trust did not hedge against any interest rate exposure.

Non-IFRS financial measures

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

(000’s)	**Three Months Ended December 31, 2013**	Three Months Ended December 31, 2012	**Year Ended December 31, 2013**	Year Ended December 31, 2012
Earnings (Loss)	**$ 156**	**$** (403)	**$ 4,914**	6,117
Add back (deduct) items not involving cash:				
Unit-based compensation – non-cash portion	(452)	(3,435)	3,859	939
Unrealized risk management loss (gain)	(97)	(240)	3,675	(2,709)
Depreciation, depletion and amortization	8,793	13,883	31,206	30,789
Loss on disposal of asset	303	-	303	-
Finance expense	91	100	314	162
Funds flow from operations	**$ 8,794**	**$** 9,905	**$ 44,271**	35,298
Add back (deduct) items not directly related to field operations:				
Realized foreign exchange loss (gain)	34	33	121	(184)
Finance expense (cash portion)	770	517	2,154	1,167
Risk management (gain) loss-realized	(183)	(506)	528	(483)
Administrative expenses	3,525	2,741	8,997	8,078
Cash settled award payments	166	127	1,189	1,086
Field netback	**$ 13,106**	$ 12,817	**$ 57,260**	44,962

Conclusions regarding the design and effectiveness of disclosure controls and procedures

Disclosure controls and procedures are controls and procedures designed to provide reasonable assurance that information required to be disclosed in reports filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis and is accumulated and communicated to the Trust's management, including the Chief Executive Officer and the Chief Financial Officer as appropriate, to allow timely decisions regarding required disclosure. As at December 31, 2013, the Chief Executive Officer and the Chief Financial Officer evaluated the design and operation of the Trust's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the Trust's disclosure controls and procedures were effective as at December 31, 2013.

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

Internal controls are processes designed and implemented by Management to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements and other financial information for external purposes in accordance with IFRS. Based on an evaluation of the Trust's internal controls over financial reporting as at December 31, 2013, the Chief Executive Officer and the Chief Financial Officer concluded that the Trust's internal controls over financial reporting were effective.

No change in internal controls over financial reporting during the period October 1, 2013 to December 31, 2013

During the period beginning on October 1, 2013 and ended on December 31, 2013, there was no change in the Trust's internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust's internal controls over financial reporting. It should be noted, that the Trust's control system, no matter how well designed, can provide only reasonable, but not absolute, assurance of detecting, preventing and deterring errors or fraud.

Note about forward-looking statements

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

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

- the Trust's 2014 capital budget and specific uses, including the Trust's 2014 drilling plans;
- the Trust's expectation regarding its 2014 average working interest production, 2014 operating costs, 2014 field netbacks and 2014 flow from operations;
- the Trust's expectation that its 2014 capital budget should be sufficient to grow 2014 average working interest production and funds flow by approximately 10% over 2013;
- the Trust's expectation that its funds flow from operations and undrawn credit facility will be sufficient to fund its current and expected financial obligations;
- projected payout ratios and the sensitivities of funds flow and payout ratios to changes in production rates and commodity prices;
- sustainability of production;
- amount of and sustainability of distributions on the Units;
- percentage weighting of oil, gas and NGLs in 2014 production;
- existing credit facilities and the availability of new credit facilities to fund acquisitions;
- cash available from the distribution reinvestment and Premium Drip™ programs;
- the taxability of the Trust and the status of the Trust as a mutual fund trust and not a SIFT trust;
- projected debt to cash flow, and management's objective to maintain a debt to cash flow ratio below 1.5 times;
- estimated reserve life index;
- the Trust's expectations regarding the potential of the emerging horizontal well play on the Permian property to add future reserves; and

- estimated volumes and value of Eagle's reserves.

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

- future oil, natural gas and NGL prices;
- future currency exchange rates;
- the regulatory framework governing taxes in the US and Canada and the Trust's status as a "mutual fund trust" and not a "SIFT trust;"
- future production levels;
- future recoverability of reserves;
- future capital expenditures and the ability of the Trust to obtain financing on acceptable terms for its capital projects and future acquisitions;
- 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;
- unitholder participation in Eagle's Premium Drip™ and distribution reinvestment programs;
- the ability of the Trust to compete for new acquisitions;
- estimates of anticipated production, which is based on the proposed drilling program with a success rate that, in turn, is based upon historical drilling success and an evaluation of the particular wells to be drilled;
- projected operating costs, which are based on historical information and anticipated increases in the cost of equipment and services; and
- the accuracy of the estimates of Eagle's reserves volumes and values.

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

- volatility of oil, natural gas and NGL prices;
- commodity supply and demand;
- fluctuations in currency and interest rates;
- inherent risks and changes in costs associated in the development of petroleum properties;
- ultimate recoverability of reserves;
- timing, results and costs of drilling and production activities;
- availability of financing and capital; and
- new regulations and legislation that apply to the Trust and the operations of its subsidiaries.

Additional risks and uncertainties affecting the Trust are contained in the Trust's December 31, 2013 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. Eagle's production rates, operating costs, 2014 capital budget, estimated reserves volumes and values, and the Trust's distributions are subject to change in light of ongoing results, prevailing economic circumstances, obtaining regulatory approvals, commodity prices and industry conditions and regulations. New factors emerge from time to time, and it is not possible for management to predict all of these factors or to assess, in advance, the impact of each such factor on the Trust's business, or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statement.

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

Note regarding barrel of oil equivalency

This MD&A contains disclosure expressed as "boe" or "boe/d". All oil and natural gas equivalency volumes have been derived using the conversion ratio of six thousand cubic feet ("**Mcf**") of natural gas to one barrel ("**bbl**") of oil. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. In addition, given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of six to one, utilizing a boe conversion ratio of 6 Mcf: 1 bbl would be misleading as an indication of value.

Eagle Energy Trust

Consolidated Financial Statements
(in Canadian dollars)

For the Years Ended December 31, 2013 and December 31, 2012

Management's Report to the Unitholders of Eagle Energy Trust

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

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

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

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

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

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

MARCH 20, 2014

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

MARCH 20, 2014

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

We have audited the accompanying consolidated financial statements of Eagle Energy Trust and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012 and the consolidated statements of earnings and comprehensive income, statements of changes in unitholders' equity and statements of cash flows for the years ended December 31, 2013 and December 31, 2012, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessments of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Eagle Energy Trust and its subsidiaries as at December 31, 2013 and December 31, 2012 and its financial performance and its cash flows for the years ended December 31, 2013 and December 31, 2012 in accordance with International Financial Reporting Standards.

(Signed) PricewaterhouseCoopers LLP

Chartered Accountants

March 20, 2014
Calgary, Alberta

Eagle Energy Trust

Consolidated Balance Sheets

(Thousands of Canadian dollars)

	Note	December 31, 2013	December 31, 2012
ASSETS			
Current assets			
Cash	16	$ 1,435	$ 4,007
Trade and other receivables	17	7,826	7,612
Prepaid expenses		628	531
Risk management asset	5	-	2,314
		9,889	**14,464**
Non-current assets			
Exploration and evaluation	18	508	422
Oil and gas properties	19	324,349	269,233
Property, plant and equipment	20	327	282
Other intangible assets	21	606	401
		325,790	**270,338**
Total Assets		**$ 335,679**	**$ 284,802**
LIABILITIES			
Current liabilities			
Trade and other payables		$ 5,929	$ 8,313
Distributions payable	22	2,813	2,570
Unit-based payments	9	9,630	6,629
Risk management liability	5	1,453	-
Current debt	23	10,636	-
		30,461	**17,512**
Non-current liabilities			
Risk management liability	5	-	123
Long-term debt	23	67,485	40,244
Deferred income tax	12	-	-
Decommissioning liability	24	3,036	1,744
		70,521	**42,111**
Total Liabilities		**$ 100,982**	**$ 59,623**
UNITHOLDERS' EQUITY			
Trust capital	25	$ 297,447	276,526
Currency reserves	10	11,100	(5,017)
Accumulated earnings (loss)		6,604	1,690
Accumulated cash distributions	22	(80,454)	(48,020)
Total Unitholders' Equity		**$ 234,697**	**$ 225,179**
Total Liabilities and Unitholders' Equity		**$ 335,679**	**$ 284,802**

The notes are an integral part of these financial statements.

See Note 28 "Commitments" and Note 29 "Subsequent events".

Eagle Energy Trust

Consolidated Statements of Earnings and Comprehensive Income

(Thousands of Canadian dollars, except per unit amounts)

	Note	Year Ended December 31, 2013	Year Ended December 31, 2012
Revenue	8	$ 98,767	$ 81,130
Royalties		(27,550)	(22,406)
		71,217	**58,724**
Operating expenses		11,412	11,753
Transportation expenses		2,545	2,009
Administrative expenses		8,998	8,078
Depreciation, depletion and amortization	13	31,206	30,790
Operating profit		**17,056**	**6,094**
Unit based compensation	9	5,049	2,023
Finance expense	11	2,467	1,330
Loss on disposal of assets	19	303	-
Risk management loss (gain)	5	4,203	(3,192)
Foreign exchange loss (gain), net	10	120	(184)
Earnings before taxes		**4,914**	**6,117**
Income tax expense (recovery)	12	-	-
Earnings		**$ 4,914**	**$ 6,117**
Other comprehensive income			
Items that may be reclassified subsequently to net income			
Foreign currency translation gain (loss)	10	16,117	(4,299)
Comprehensive income		**$ 21,031**	**$ 1,818**
Earnings per unit			
Basic	15	0.16	0.25
Diluted	15	0.16	0.24

The notes are an integral part of these financial statements.

Eagle Energy Trust

Consolidated Statement of Changes in Unitholders' Equity

For the years ended December 31, 2013 and December 31, 2012
(Thousands of Canadian dollars)

	Note	Number of Trust Units (000's)	Trust Capital	Currency Reserve	Accumulated Earnings/ Loss	Accumulated Cash Distributions	Deficit	Total Unitholders' Equity
Balance at December 31, 2011		**18,544**	**168,175**	**(718)**	**(4,427)**	**(21,204)**	**(25,631)**	**141,826**
Earnings		-	-	-	6,117	-	6,117	6,117
Foreign currency translation gain (loss)	10	-	-	(4,299)	-	-	-	(4,299)
Total comprehensive income		-	-	(4,299)	6,117	-	6,117	1,818
Issuance of Trust capital	25	10,725	114,694	-	-	-	-	114,694
Trust unit issuance costs	25	-	(6,343)	-	-	-	-	(6,343)
Unitholder distributions	22	-	-	-	-	(26,816)	(26,816)	(26,816)
		10,725	108,351	-	-	(26,816)	(26,816)	81,535
Balance at December 31, 2012		**29,269**	**276,526**	**(5,017)**	**1,690**	**(48,020)**	**(46,330)**	**225,179**
Earnings		-	-	-	4,914	-	4,914	4,914
Foreign currency translation gain (loss)	10	-	-	16,117	-	-	-	16,117
Total comprehensive income		-	-	16,117	4,914	-	4,914	21,031
Issuance of Trust capital	25	2,880	21,032	-	-	-	-	21,032
Trust unit issuance costs	25	-	(111)	-	-	-	-	(111)
Unitholder distributions	22	-	-	-	-	(32,434)	(32,434)	(32,434)
		2,880	20,921	-	-	(32,434)	(32,434)	(11,513)
Balance at December 31, 2013		**32,149**	**297,447**	**11,100**	**6,604**	**(80,454)**	**(73,850)**	**234,697**

The notes are an integral part of these financial statements.

Eagle Energy Trust

Consolidated Cash Flow Statements

For the year ended December 31, 2013 and December 31, 2012
(Thousands of Canadian dollars)

	Note		**Year Ended December 31, 2013**		Year Ended December 31, 2012
Cash flows from operating activities					
Net cash generated by operating activities	26	**$**	**41,683**	**$**	**34,187**
Cash flows from investing activities					
Additions to exploration and evaluation			(63)		(303)
Additions to oil and gas properties			(30,054)		(42,880)
Additions to property, plant and equipment			(215)		(274)
Acquisition of oil and gas assets	7		(35,855)		(115,902)
Proceeds from disposal of assets			106		-
Net cash used in investing activities		**$**	**(66,081)**	**$**	**(159,359)**
Cash flows from financing activities					
Long-term debt			34,827		40,683
Proceeds from issuance of units			21,032		111,915
Trust unit issue costs			(111)		(6,343)
Cash distributions to unitholders			(32,191)		(25,902)
Change in non-cash working capital			(859)		2,778
Deferred financing charges			(430)		(345)
Net cash generated by financing activities		**$**	**22,268**	**$**	**122,786**
Net increase (decrease) in cash and cash equivalents			**(2,130)**		**(2,386)**
Effects of exchange rates on cash and cash equivalents			(442)		(1,102)
Cash at beginning of the period			4,007		7,495
Cash at end of the period	16	**$**	**1,435**	**$**	**4,007**

The notes are an integral part of these financial statements.

Eagle Energy Trust

Notes to Consolidated Financial Statements

For the years ended December 31, 2013 and December 31, 2012
(in Canadian dollars)

1. Reporting entity / Structure of the Trust

Eagle Energy Trust's activities are restricted to owning property (other than real property or interests in real property), and it does not carry on business. Eagle Energy Trust's subsidiaries are in the business of acquiring, developing and producing petroleum reserves in the United States. Eagle Energy Trust was formed as an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta on July 20, 2010. The beneficiaries of the Trust are the unitholders.

Throughout these notes to the consolidated financial statements, Eagle Energy Trust and its subsidiaries are referred to collectively as the "Trust" or "Eagle" for purposes of convenience. For a list of subsidiaries and a detailed description of the structure of the Trust, refer to note 6 "Subsidiaries and consolidated entities".

The strategy of the Trust is to invest in operating subsidiaries that will acquire on-shore petroleum reserves and production in certain regions of the United States. The Trust's subsidiaries do not intend to engage substantively in exploration activities. The Trust intends to make monthly distributions of a portion of its available cash to unitholders and use the remainder of its available cash to reinvest in its subsidiaries to fund growth through additional acquisitions and capital expenditures. Cash flow is provided to the Trust from properties owned and operated by an indirectly owned subsidiary of the Trust.

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

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

2.1. Basis of preparation

Basis of accounting

The consolidated financial statements were authorized for issue in accordance with a resolution of the Board of Directors made on March 20, 2014.

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

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

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

Basis of consolidation

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

A list of the subsidiaries has been included in note 6 “Subsidiaries and consolidated entities”.

2.2 Changes in accounting policy and disclosures

New and revised standards adopted

The Trust adopted the following new and revised standards, along with any consequential amendments, effective January 1, 2013. These changes were made in accordance with the applicable transitional provisions.

- IAS 1, Presentation of Financial Statements. The Trust adopted the amendments to IAS 1 effective January 1, 2013. These amendments required the Trust to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. The Trust has reclassified comprehensive income items of the comparative period. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

- IFRS 10, Consolidated Financial Statements, replaces the guidance on control and consolidation in IAS 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation - Special Purpose Entities. The Trust assessed its consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of any of its subsidiaries.

- IFRS 11, Joint Arrangements, supersedes IAS 31, Interests in Joint Ventures, and requires joint arrangements to be classified either as joint operations or joint ventures depending on the contractual rights and obligations of each investor that jointly controls the arrangements. The Trust has classified its joint arrangements and concluded that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements.

- IFRS 13, Fair Value Measurement, provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. The Trust adopted IFRS 13 on January 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Trust to measure fair value and did not result in any measurement adjustments.

- IAS 19, Employee Benefits (amended in 2011), amends certain accounting requirements for defined benefits plans and termination benefits. These changes do not impact the Trust and it did not result in any adjustments to the Financial Statements.

- IAS 36, Impairment of assets – Disclosures, addresses the disclosure of information about the recoverable amount of impaired assets if that amount is based on fair value less costs of disposal. The amendments to IAS 36 are effective January 1, 2014. The Trust adopted the amendment in the current period and concluded that the adoption of IAS 36 did not result in any changes to the disclosure of impaired assets in 2013.

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

2.3 Significant accounting policies

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

Business combinations

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

Joint arrangements

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

Foreign currency

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

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

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

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

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

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

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

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

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

Financial instruments

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

A. Non-derivative financial instruments

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

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

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

(a) Financial assets

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

(i) Loans and receivables

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

Cash is comprised of cash on hand.

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

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

(ii) Impairment of financial assets

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

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

(b) Financial liabilities and equity

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

(i) Trade payables and distributions payable

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

(ii) Borrowings

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

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

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

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

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

(iii) Equity instruments

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

(iv) Compound instruments

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

B. Derivative financial instruments

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

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

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

(a) Fair Value Hierarchy

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

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

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

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

Non-current assets held for sale

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

Exploration and evaluation expenditures

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

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

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

Oil and gas properties

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

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

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

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

Impairment - Exploration and evaluation expenditures

Exploration and evaluation assets are assessed for impairment if:

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

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

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

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

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

Impairment – Oil and gas properties

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

Decommissioning provision

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

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

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

Property, plant and equipment

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

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

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

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

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

Revenue recognition

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

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

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

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

Unit-based compensation

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

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

Finance income and expense

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

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

Unitholder distributions

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

Taxation

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

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

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

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

Eagle Energy Trust is a taxable entity under the Income Tax Act (Canada) ("Tax Act") and is currently taxable only on income that is not distributed or distributable to the unitholders. Eagle Energy Trust distributes all of its taxable income to the unitholders and expects to continue to distribute all of its taxable income to unitholders. The Trust was at no time a SIFT trust as defined in the Tax Act. Investment restrictions contained in the formation documents provide that the Trust and its subsidiaries will only invest in entities that qualify as a "portfolio investment entity" and will not hold any "non-portfolio property" or "taxable Canadian property", each as defined in the Tax Act. It also qualifies as a "mutual fund trust" within the meaning of the Tax Act and will not be subject to the limit on non-resident ownership in the Tax Act as long as it does not own any "taxable Canadian property" as defined in the Tax Act.

Eagle Energy Trust's indirect subsidiary is in the business of acquiring, developing and producing oil and natural gas reserves in the United States. As a general rule, a foreign corporation engaged in a United States trade or business is subject to U.S. federal income tax on income that is effectively connected (effectively connected income, or "ECI") with the United States trade or business and, if an income tax treaty with the United States applies, is attributable to a permanent establishment maintained by the foreign corporation in the United States. ECI is subject to United States federal income tax on a net basis at the regular United States federal graduated rates of tax that apply to United States persons. A foreign corporation's taxable income is computed by claiming deductions that are attributable to the effectively connected gross income on a timely filed return. A foreign corporation that derives ECI (including amounts received as a partner through a partnership or disregarded entity) is generally required to make quarterly payments of estimated United States tax, and is required to file a United States federal income tax return. A subsidiary of Eagle Energy Trust, Eagle Energy Commercial Trust, has elected under applicable United States Treasury Regulations to be treated as a corporation for United States federal income tax purposes effective on the date of formation and is generally subject to United States federal income tax on its net taxable income (including income related to the Salt Flat Field and Midland Area which is ECI). Eagle Energy Commercial Trust deducts interest paid on certain intercompany notes and other deductible expenses, including intangible drilling and developments costs and depletion in calculating its US taxable income.

Trust unit calculations

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

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

3. Critical accounting estimates and judgments

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

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

Estimation of oil and natural gas reserves

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

Capitalized exploration and evaluation expenditures

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

Decommissioning provision

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

Impairment indicators

The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions. It is reasonably possible that the commodity price assumption may change, which may impact the estimated life of the asset and may require a material adjustment to the carrying value of assets. The Trust monitors internal and external indicators of impairment relating to its tangible and intangible assets and discount rate estimates.

Income taxes

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

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

Derivative financial instruments

As described in note 5 "Financial risk management", derivative financial instruments are used by the Trust to manage its exposure to market risks relating to commodity prices. The Trust's policy is not to use derivative financial instruments for speculative purposes. Derivative financial instruments that do not qualify, or are not designated, as hedges for accounting are recorded at fair value. Instruments are recorded in the balance sheet as either an asset or a liability with changes in fair value recognized in the income statement. The estimate of fair value of all derivative instruments is based on quoted market prices, or in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Classification of Trust units as equity

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

Contingencies

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

Unit Based Compensation

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

4. Determination of fair values

Effective January 1, 2013, the Trust adopted, as required, IFRS 13, "Fair Value Measurement". The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no change to the Trust's methodology for determining the fair value for its financial assets and liabilities and, as such, the adoption of IFRS 13 did not result in any measurement adjustments as at January 1, 2013.

Debt is a financial asset with fixed or determinable payments that is not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method.

5. Financial risk management

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

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

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

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

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

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

Credit risk

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

$000's		**December 31, 2013**		December 31, 2012
Cash	$	1,435	$	4,007
Trade and other receivables		7,826		7,612
Risk management asset		-		2,314
	$	**9,261**	$	13,933

Cash

The Trust limits its exposure to credit risk by investing only in liquid securities and only with counterparties with a strong credit rating. Additionally, the Trust enters into certain risk management contracts periodically to economically hedge a portion of its oil and natural gas sales. Given this approach, Management does not expect any counterparty to fail to meet its obligations as at December 31, 2013.

Trade and other receivables

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

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

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

The Trust does not anticipate any default as it transacts with creditworthy customers and Management does not expect any losses from non-performance by these customers. As such, no provision for doubtful accounts has been recorded at December 31, 2013 and December 31, 2012.

Risk management asset

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

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

$000's		**December 31, 2013**		December 31, 2012
Oil and natural gas marketing companies	$	6,458	$	5,374
Receivable from joint venture working interest owners		1,158		2,068
Other		210		170
	$	**7,826**	$	7,612

The Trust's most significant customers are two US oil and natural gas marketers and account for approximately 83% or $6,458,717 of trade receivables at December 31, 2013 and approximately 71% or $5,373,630 at December 31, 2012. Additionally, 15% or $1,157,921 represents billed and accrued receivables from joint venture working interest partners at December 31, 2013 and 27% or $2,068,425 at December 31, 2012. As of December 31, 2013 and

December 31, 2012, substantially all of the receivables were considered current (less than 90 days old) and none were considered impaired.

Liquidity risk

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

At December 31, 2013, the Trust had a working capital deficiency, excluding the non-revolving term credit facility, of approximately $10.3 million. In addition, the Trust had in total a $US 90 million credit facility which consists of a $US 80 million revolving credit facility and a $US 10 million non-revolving term credit facility. At December 31, 2013, $US 16.6 million credit was available under the revolving facility, and the non-revolving term credit facility was fully drawn, see note 23 "Debt". To better manage its liquidity risk, the Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures ("AFEs") on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil and natural gas revenue each month.

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

$ 000's	Carrying amount	Contractual cash flows	Less than one year	One – two years	Two – five years	More than five years
Trade and other payables	$ 5,929	$ 5,929	$ 5,929	$ -	-	-
Distributions payable	2,813	2,813	2,813	-	-	-
Risk management liability	1,453	1,453	1,453	-	-	-
Current debt	10,695	10,695	10,695	-	-	-
Long-term debt	69,508	-	-	69,508	-	-
	$ 90,398	**$ 20,890**	**$ 20,890**	**$ 69,508**	**-**	**-**

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

The following were the contractual undiscounted maturities of financial liabilities, including estimated interest payments, as applicable, at December 31, 2012:

$ 000's	Carrying amount	Contractual cash flows	Less than one year	One – two years	Two – five years	More than five years
Trade and other payables	$ 8,313	$ 8,313	$ 8,313	$ -	-	-
Distributions payable	2,570	2,570	2,570	-	-	-
Risk management liability	123	123	-	123	-	-
Long-term debt	41,321	-	-	41,321	-	-
	$ 52,327	$ 11,006	$ 10,883	$ 41,444	-	-

The Trust units contain a redemption feature, see note 25 "Trust capital". Utilizing the terms of redemption as outlined in note 25, the total market redemption price for all outstanding units at December 31, 2013 would be $229,446,764 ($7.93 per unit 10 day volume weighted average price x 90% x 32,148,909 units); and $202,193,541 ($7.65 per unit 10 day volume weighted average price x 90% x 29,374,560 units) at December 31, 2012. As the maximum cash outlay required by the Trust is capped at $100,000 per month or $1,200,000 per year, the Trust would have approximately 191 years to pay out this commitment (168 years at December 31, 2012).

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 or 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.

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

1. A fixed contract to sell 400 barrels of oil per day with a January 2014 through December 2014 term at a price of $US 98.00 per barrel.

2. A call swaption to sell 500 barrels of oil per day with a January 2014 through December 2014 term at a price of $US 100.00 per barrel.

3. A fixed contract to sell 500 barrels of oil per day with a January 2014 through December 2014 term at a price of $US 91.15 per barrel.

4. A fixed contract to sell 400 barrels of oil per day with a January 2014 through December 2014 term at a price of $US 91.15 per barrel.

5. A costless collar contract for 250 barrels of oil per day with a January 2014 through December 2014 term at a floor of $US 90.00 per barrel and a ceiling of $US 94.95 per barrel.

6. A costless collar contract for 100 barrels of oil per day with a January 2014 through December 2014 term at a floor of $US 93.00 per barrel and a ceiling of $US 95.35 per barrel.

Summary of Unrealized Risk Management Positions as at December 31, 2013

	Volume	***Measure***	***Beginning***	***Term***	***Floor $US***	***Ceiling $US***	***Current net present value (NPV) $000's $CA***	***Non-current net present value (NPV) $000's $CA***
Oil Fixed Price								
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	98.00	98.00	374	-
NYMEX (iii)	500	bbls/d	Jan-14	Dec-14	100.00	100.00	-	-
NYMEX (i)	500	bbls/d	Jan-14	Dec-14	91.15	91.15	(860)	-
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	91.15	91.15	(688)	-
NYMEX (ii)	250	bbls/d	Jan-14	Dec-14	90.00	94.95	(237)	-
NYMEX (ii)	100	bbls/d	Jan-14	Dec-14	93.00	95.35	(42)	-
							$ (1,453)	**$ -**

(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).
(iii) Represents a call swaption financial transaction with a set forward sale price (WTI reference prices).

Summary of Unrealized Risk Management Positions as at December 31, 2012

	Volume	*Measure*	*Beginning*	*Term*	*Floor $US*	*Ceiling $US*	*Current net present value (NPV) $000's $CA*	*Non-current net present value (NPV) $000's $CA*
Oil Fixed Price								
NYMEX (i)	300	bbls/d	May-12	Apr-13	95.00	108.25	286	-
NYMEX (ii)	200	bbls/d	Jan-13	Apr-13	103.45	103.45	258	-
NYMEX (ii)	500	bbls/d	May-13	Dec-13	103.45	103.45	1,207	-
NYMEX (ii)	400	bbls/d	Jan-14	Dec-14	98.00	98.00	-	844
NYMEX (i)	250	bbls/d	Aug-12	Jul-13	87.00	89.70	(221)	-
NYMEX (i)	250	bbls/d	Sept-12	Aug-13	90.00	91.60	(77)	-
NYMEX (i)	300	bbls/d	Jan-13	Jul-13	95.00	103.75	282	-
NYMEX (i)	500	bbls/d	Aug-13	Aug-13	95.00	103.75	75	-
NYMEX (i)	800	bbls/d	Sep-13	Dec-13	95.00	103.75	504	-
NYMEX (iii)	500	bbls/d	Jan-14	Dec-14	100.00	100.00	-	(967)
							$ 2,314	**$ (123)**

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

Net Unrealized Risk Management Position

($ 000's)	**December 31, 2013**	December 31, 2012
Current asset (liability)	$ (1,453)	$ 2,314
Non-current liability	-	(123)
Net risk management asset (liability)	**$ (1,453)**	$ 2,191

The total net fair value of Eagle's unrealized risk management positions at December 31, 2013 is a liability of $1,453,286 (December 31, 2012 - $2,190,308 asset) and has been calculated using both quoted prices in active markets and observable market-corroborated data consistent with a Level 2 valuation.

Reconciliation of Net Unrealized Risk Management Position

$000's	**December 31, 2013** Net present value (NPV)	**December 31, 2013** Total net risk management asset (liability)	December 31, 2012 Net present value (NPV)	December 31, 2012 Total net risk management asset (liability)
Fair value of contracts, beginning of year	$ 2,191	$ 2,191	$ (503)	$ (503)
Fair value of contracts realized during the period	(528)	(528)	483	483
Fair value of contracts unrealized during the period	(3,675)	(3,675)	2,709	2,709
Effects of exchange rate	559	559	(498)	(498)
Fair value of contracts	**$ (1,453)**	**$ (1,453)**	$ 2,191	$ 2,191

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

$000's	**December 31, 2013** Realized (loss)	**December 31, 2013** Unrealized (loss)	**December 31, 2013** Total net (loss)	December 31, 2012 Realized gain	December 31, 2012 Unrealized gain	December 31, 2012 Total net gain
Net effect - risk management	**$ (528)**	**$ (3,675)**	**$ (4,203)**	$ 483	$ 2,709	$ 3,192

A 10% increase (decrease) in the market price of oil from its 2013 year average of $US 97.98 WTI would have increased (decreased) income by approximately $2.0 million based on the risk management instruments outstanding at December 31, 2013. A 10% increase (decrease) in the market price of oil from its 2012 year average of $US 94.21 WTI would have increased (decreased) income by approximately $6.4 million in 2012. This analysis assumes that all other variables remain constant.

Foreign exchange risk

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. The Trust's operating cash flows are generated in US dollars and distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust's treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil are determined in global markets and generally denominated in US dollars. Generally an increase in the value of the $CA as compared to the $US will reduce the prices received by the Trust for its petroleum and natural gas sales but will also reduce the operating expenses associated with those sales, as well as reduce the price paid by the subsidiary of the Trust for future asset acquisitions.

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

As at December 31, 2013 ($ 000's)		$US		$CA
Cash	$	23	$	24
Trade and other receivables		7,160		7,615
Trade and other payables		(4,593)		(4,885)
Risk management liability		(1,366)		(1,453)
Current debt		(10,000)		(10,636)
	$	**(8,776)**	**$**	**(9,335)**

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

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

As at December 31, 2012 ($ 000's)		$US		$CA
Cash	$	2,523	$	2,510
Trade and other receivables		7,501		7,463
Risk management asset		2,325		2,314
Trade and other payables		(7,764)		(7,700)
	$	**4,585**	**$**	**4,587**

The average exchange rate during the period ending December 31, 2012 was $US 1 equal to $CA 0.99, and the exchange rate at December 31, 2012 was $US 1 equal to $CA 0.99.

A 10% strengthening (weakening) in the Canadian dollar against the US dollar at December 31, 2012 of $CA 0.99 ($US 1.00) would have decreased (increased) income by approximately $2.0 million. This analysis assumes that all other variables remain constant.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. As at December 31, 2013, $US 63.4 million had been drawn against the revolving $US 80 million credit facility and the $US 10 million non-revolving term credit facility was fully drawn. Borrowings are by way of LIBOR and base rate loans. See note 23, "Debt". At December 31, 2013 and December 31, 2012, there were no covenant violations to the loan agreement.

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

Capital management

The Trust's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Trust manages its capital structure and makes adjustments to it based upon economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include working capital, loans and borrowing, and unitholders' equity. In order to maintain or adjust the capital structure, the Trust may issue units, engage in external debt financing, and adjust its capital spending to manage current and projected debt levels. The Trust monitors capital based on the ratio of external debt to cash generated from operations. This ratio is calculated as external debt, defined as outstanding loans and borrowings, plus or minus working capital deficit or surplus divided by annualized cash generated from operations before changes in non-cash working capital. Management's objective is to maintain an external debt to estimated future annual cash flow ratio not to exceed 1.5 to 1.0. This ratio may increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Trust prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at December 31, 2013, the Trust's ratio of external debt to annualized cash flow was above the range targeted by the Trust due to the acquisition of the Hardeman Properties (see note 7(b) Acquisitions) that closed November 25, 2013.

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

Draws against the existing credit facility would be subject to established covenants. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves. See note 23 "Debt".

6. Subsidiaries and consolidated entities

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

Subsidiary	Country of Formation	Nature of Business	Footnotes
Eagle Energy Commercial Trust	Canada	Alberta Trust	(1)
Eagle Energy Acquisitions LP	United States	Delaware, LP	(2)
Eagle Hydrocarbons LLC	United States	Delaware, LLC	(3)

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

(2) On September 28, 2010, Eagle Energy Acquisitions LP, a limited partnership, was created by Eagle Energy Commercial Trust by way of a certificate of limited partnership. Eagle Energy Acquisitions LP is a limited partnership formed under the laws of the State of Delaware with a general mandate to engage in the business of acquiring, developing, and producing oil and natural gas reserves in the United States.

(3) On September 28, 2010, Eagle Hydrocarbons LLC was formed to be the general partner of, and acquire and hold the remaining 0.001% interest in, Eagle Energy Acquisitions LP. Eagle Hydrocarbons LLC is a limited liability company formed under the laws of the State of Delaware. The sole member of Eagle Hydrocarbons LLC is Eagle Energy Commercial Trust.

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

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

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

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

Eagle Energy Inc. meets the accounting definition of a special purpose entity and, accordingly, Eagle Energy Inc. has been consolidated based on the principles set out in IFRS 10 – Consolidated Financial Statements.

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

7. Acquisitions

(a) Non-Financial Forward Purchase Contract

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

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

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

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

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

(b) Hardeman Properties

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

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

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

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

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

8. 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, currently in the state of Texas, and are supported by offices in Houston, Luling, and Midland. 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.

9. Unit-based payments

The following table reconciles unit-based compensation expense.

$ 000's	Note	**Year Ended December 31, 2013**	Year Ended December 31, 2012
Units issued on performance option surrender	9 (a)	270	1,238
Restricted unit rights	9 (b)	762	304
Unit options	9 (c)	3,016	229
Unit rights	9 (d)	1,001	252
Total unit-based compensation expense		**$ 5,049**	$ 2,023

The following table recognizes the unit-based payments liability.

$ 000's	Note	**Year Ended December 31, 2013**	Year Ended December 31, 2012
Units issued on performance option surrender	9 (a)	-	589
Restricted unit rights	9 (b)	1,240	1,588
Unit options	9 (c)	6,998	3,982
Unit rights	9 (d)	1,392	470
Total unit-based payments liability		**$ 9,630**	$ 6,629

Grant, surrender and replacement of performance options

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

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

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

Note (a)

Units issued upon surrender of performance options

At December 31, 2013, no escrowed units were outstanding. On November 24, 2010, the Trust issued and placed into escrow 387,500 units upon surrender of performance options. Two-thirds of those escrowed units were released on September 14, 2012 and the remaining one-third were released from escrow on September 14, 2013. The fair value estimate associated with the escrowed units was expensed in the income statement over the escrow period, which is the same period as the performance conditions, with the offsetting entry to unit-based payments liability. Upon release of the units from escrow, the accumulated liability was then transferred to Trust capital.

The following schedule shows the continuity of escrowed units issued upon surrender of performance options:

	Year Ended December 31, 2013	Year Ended December 31, 2012
Balance, beginning of period	105,417	387,500
Issued	-	-
Transferred to the Trust capital account	105,417	(282,083)
Balance, end of period in escrow	**-**	105,417

Note (b)

Cash settled RURs issued upon surrender of performance options

At December 31, 2013, all RURs had vested. Each RUR entitles the holder to receive cash payments equal to the distributions payable on one unit as well as capital appreciation of units. For the year ended December 31, 2013, an aggregate of $1,110,734 has been paid to the RUR holders (year ended December 31, 2012 - $1,086,248).

The fair value estimate associated with the RURs is expensed in the income statement with the offsetting entry to unit-based payments liability. At December 31, 2013, the fair value of the RURs was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period with the corresponding change to fair value being recognized in the income statement.

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

	Year Ended December 31, 2013	Year Ended December 31, 2012
Balance, beginning of period	632,500	775,000
Issued	-	-
Forfeited	-	(142,500)
Balance, end of period	632,500	632,500
Number of RURs vested	**632,500**	421,667

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

	Year Ended December 31, 2013	Year Ended December 31, 2012
Fair value at the balance sheet date	**$** 5.72	$ 4.48
Volatility	32%	32%
Life of RURs	7.0 years	8.0 years
Risk-free interest rate	2.70%	1.82%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Given the limited history of the Trust, which commenced trading on November 24, 2010, a representative sample of peer group entities was used in order to determine expected unit price volatility.

Note (c)

Unit option plan

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

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

The fair value estimate associated with the options is expensed in the income statement over the vesting period with the offsetting entry to unit-based payments liability. At December 31, 2013, the fair value of the options was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period with the corresponding change to fair value being recognized in the income statement.

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

	Year Ended December 31, 2013			Year Ended December 31, 2012		
	Number of options		Weighted average exercise price	Number of Options		Weighted average exercise price
Outstanding, beginning of period	2,214,668	$	8.23	1,706,000	$	8.88
Forfeited	(249,918)		7.69	(258,332)		8.32
Exercised	-		-	-		-
Granted	1,162,000		6.72	767,000		9.15
Outstanding at end of period	**3,126,750**	**$**	**7.05**	2,214,668	$	8.23
Exercisable at end of period	**1,411,010**	**$**	**7.00**	992,006	$	7.85

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

		Weighted average exercise price	Weighted average contractual life (years)
$5.92 - $8.22	**$**	**7.05**	**8.4**

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

		Year Ended December 31, 2013		Year Ended December 31, 2012
Fair value - at balance sheet date	**$**	3.76	$	2.93
Unit trading price - closing	**$**	8.07	$	7.69
Exercise price – weighted average	**$**	7.05	$	8.23
Volatility		32%		32%
Option life – weighted average		8.4 years		8.6 years
Distributions – none estimated, due to declining strike price feature		0%		0%
Risk-free interest rate		2.70%		1.82%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. This estimate will be adjusted to the actual forfeiture rate. Given the limited trading history of the Trust, which commenced trading on November 24, 2010, a representative sample of peer group entities was used in order to determine expected unit price volatility.

Note (d)

Unit Rights (URs) plan

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

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

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

For the year ended December 31, 2013, an aggregate of $78,668 has been paid to the UR holders (year ended December 31, 2012 - $ nil).

The fair value estimate associated with the URs is expensed in the income statement over the vesting period with the offsetting entry to unit-based payments liability. At December 31, 2013, the fair value of the URs was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period with the corresponding change to fair value being recognized in the income statement.

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

	Year Ended December 31, 2013	Year Ended December 31, 2012
Balance, beginning of period	493,000	185,000
Issued	649,000	338,000
Forfeited	(145,000)	(30,000)
Balance, end of period	**997,000**	493,000
Number of unit rights vested	**152,670**	51,670

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

	Year Ended December 31, 2013	Year Ended December 31, 2012
Fair value at the balance sheet date	**$** 3.62	$ 2.66
Volatility	32%	32%
Life of restricted URs	9.2 years	9.3 years
Risk-free interest rate	2.70%	1.82%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Given the limited trading history of the Trust, which commenced trading on November 24, 2010, a representative sample of peer group entities was used in order to determine expected unit price volatility.

10. Foreign exchange

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

$ 000's		**Year Ended December 31, 2013**		Year Ended December 31, 2012
Net loss (gain) arising on settlement of foreign currency transactions arising out of operating activities	**$**	**120**	$	(184)

The currency in which these transactions and balances are primarily denominated is US dollars and, as such, the Trust is not exposed to significant foreign exchange risk. See note 5 "Financial risk management".

$ 000's		**Year Ended December 31, 2013**		Year Ended December 31, 2012
Beginning balance	$	(5,017)	$	(718)
Foreign currency translation gain (loss)		16,117		(4,299)
Ending balance	**$**	**11,100**	$	(5,017)

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

11. Finance expense

$ 000's		**Year Ended December 31, 2013**		Year Ended December 31, 2012
Interest expense on long-term debt	$	2,082	$	1,075
Amortization of deferred financing costs		254		135
Standby and bank fees		72		95
Accretion of decommissioning provision		59		25
Finance expense	**$**	**2,467**	$	1,330

12. Taxation

Reconciliation of effective tax rate

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

$ 000's			Year Ended December 31, 2013			Year Ended December 31, 2012
Earnings (loss) before taxation		$	4,914		$	6,117
Expected tax rate			35%			35%
Expected income tax provision (recovery)			1,720			2,141
Decrease (Increase) resulting from:						
Non-deductible items – permanent differences						
Administrative expenses of the Trust	35%		266	35%		997
Unit-based compensation	35%		1,767	35%		708
Other expenses of the Trust	35%		58	35%		-
Changes in temporary differences for which no amounts are recognized	35%		2,827	35%		973
Return to provision true up	35%		(848)	35%		-
Items deductible at the subsidiary level						
Interest on internal debt of subsidiary	35%		(5,530)	35%		(4,856)
Other	35%		(260)	35%		37
Total income tax expense (recovery)	35%	**$**	-	35%	$	-

Deferred tax assets and liabilities:

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

$ 000's		Year Ended December 31, 2013		Year Ended December 31, 2012
Deferred tax liabilities:				
Oil and gas properties in excess of tax value	$	21,440	$	17,989
Exploration and evaluation assets		-		-
		21,440		17,989
Less deferred tax assets:				
Non-capital losses – US based		(26,841)		(20,562)
Net deferred tax liability (asset) – before valuation allowance		(5,401)		(2,573)
Unrecognized deferred tax asset		5,401		2,573
Net deferred tax liability (asset)	$	-	$	-

Movement in temporary differences during the year:

	Statement of earnings (loss)				Balance sheet			
$ 000's								
For the year ended December 31,		**2013**		2012		**2013**		2012
Oil and gas properties	$	3,451	$	5,895	$	21,440	$	19,013
Non-capital tax losses - U.S. based		(6,279)		(7,449)		(26,841)		(21,586)
	$	**(2,828)**	$	(1,554)	**$**	(5,401)	$	(2,573)

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

13. Depreciation, depletion and impairment

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

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

	Year ended December 31, 2012					
$ 000's		Oil and gas properties		Property, plant and equipment		Total
Depreciation, depletion and amortization	$	24,451	$	112	$	24,563
Impairment		6,096		-		6,096
Decommissioning liability loss		131		-		131
	$	**30,678**	**$**	**112**	**$**	**30,790**

14. Employees and key management

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

$ 000's		**Year ended December 31, 2013**		Year ended December 31, 2012
Salaries and wages	$	5,138	$	3,514
Benefits and other personnel costs		503		337
Unit-based payments (i)		3,791		1,375
Total employee and executive remuneration	**$**	**9,432**	$	5,226

(i) Represents the amortization of unit based compensation as recorded in the financial statements. See Note 9 "Unit-based payments".

Key management personnel includes Eagle's Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, Vice-President Business Development, Vice-President Finance, General Counsel/Corporate Secretary and the Directors. Figures below include amounts paid to the US Controller pursuant to his departure date of August 15, 2013. The aggregate remuneration of key management personnel was as follows:

$ 000's		**Year ended December 31, 2013**		Year ended December 31, 2012
Directors' fees	$	171	$	176
Salaries and wages		2,469		3,011
Benefits and other personnel costs		121		108
Unit-based payments (i)		4,254		1,852
Total key management remuneration	**$**	**7,015**	$	5,147

(i) Represents the amortization of unit based compensation as recorded in the financial statements. See note 9 "Unit-based payments".

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

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

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

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

15. Earnings per unit

$ 000's		**Year Ended December 31, 2013**		Year Ended December 31, 2012
Earnings attributable to unitholders	$	4,914	$	6,117
Weighted average number of units outstanding (basic)		30,650		24,689
Dilutive effect of stock options		-		1,808
Weighted average effect of stock options (diluted)		30,650		26,497
Earnings per unit (basic)	**$**	**0.16**	$	0.25
Earnings per unit (diluted)	**$**	**0.16**	$	0.24

Calculation

Basic income per unit for the year ended December 31, 2013 is calculated by dividing the income attributable to unitholders of the Trust by the weighted average number of units outstanding during the period. Diluted income per unit is calculated using the income for the period divided by the weighted average number of units outstanding assuming the conversion of potentially dilutive equity instruments outstanding.

Per unit amounts

Diluted income per unit for the year ended December 31, 2013 is equal to basic income per unit as it was determined that the conversion of potentially dilutive equity instruments would be anti-dilutive.

16. Cash

$ 000's		December 31, 2013		December 31, 2012
Cash in banks	**$**	**1,435**	$	4,007

As of December 31, 2013 and December 31, 2012, there are no compensating balance arrangements that place restrictions on the use of available cash.

17. Trade and other receivables

$ 000's		December 31, 2013		December 31, 2012
Trade receivables	$	7,758	$	7,398
Other		51		176
GST		17		38
	$	**7,826**	$	7,612

Trade receivables that are less than three months past due are not considered impaired. As of December 31, 2013 and December 31, 2012, there were no receivables considered impaired and thus no balances against which a doubtful allowance has been provided.

18. Exploration and evaluation assets

$ 000's		December 31, 2013		December 31, 2012
Beginning balance	$	422	$	119
Additions		86		303
Ending balance	**$**	**508**	$	422

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

19. 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, 2012	$	304,175	$	6,962	$	1,715	$	312,852
Additions		88,229		581		1,229		90,039
Disposals		-		(437)		-		(437)
At December 31, 2013	**$**	**392,404**	**$**	**7,106**	**$**	**2,944**	**$**	**402,454**
Accumulated depreciation and impairment								
At December 31, 2012	$	(41,184)	$	(2,435)	$	-	$	(43,619)
Depreciation		(32,922)		(1,564)		-		(34,486)
At December 31, 2013	**$**	**(74,106)**	**$**	**(3,999)**	**$**	**-**	**$**	**(78,105)**
Net book value								
At December 31, 2012	$	262,991	$	4,527	$	1,715	$	269,233
Net change for the period		55,307		(1,420)		1,229		55,116
At December 31, 2013	**$**	**318,298**	**$**	**3,107**	**$**	**2,944**	**$**	**324,349**

$ 000's		Developed oil and gas assets		Production facilities and equipment		Capitalized future decom-missioning costs		Total
Cost								
At December 31, 2011	$	154,365	$	3,356	$	491	$	158,212
Additions		149,810		3,606		1,224		154,640
At December 31, 2012	$	304,175	$	6,962	$	1,715	$	312,852
Accumulated depreciation and impairment								
At December 31, 2011	$	(12,555)	$	(590)	$	-	$	(13,145)
Depreciation		(22,560)		(1,845)		-		(24,405)
Impairment		(6,069)		-		-		(6,069)
At December 31, 2012	$	(41,184)	$	(2,435)	$	-	$	(43,619)
Net book value								
At December 31, 2011	$	141,810	$	2,766	$	491	$	145,067
Net change for the period		121,181		1,761		1,224		124,166
At December 31, 2012	$	262,991	$	4,527	$	1,715	$	269,233

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $US 101,436,200 (December 31, 2012 - $US 117,479,500) were included in the depletion calculation. Additions to "Developed oil and gas assets" include both the 7.5% Permian Acquisition and the Hardeman Acquisition. See note 7 "Acquisitions".

Impairment oil and gas properties

The Trust tested its CGUs for impairment at December 31, 2013, and no impairment was recognized in its oil and gas properties.

For the year ended December 31, 2012, due to technical reserve revisions, an impairment of $6.1 million was recognized on its oil and gas properties in relation to the Salt Flat CGU. The recoverable amounts of the Trust's CGUs were estimated as the fair value less costs to sell based on the net present value of the after tax cash flows from oil and gas proved plus probable reserves estimated by the Trust's third party reserve evaluators discounted at a rate of 8%. A 1% increase (decrease) in the discount rate would have decreased (increased) the fair value estimate by approximately $20.4 million. In addition, a 10% increase (decrease) in the estimated future cash flows would have increased (decreased) the fair value estimate by $37.6 million.

In determining 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 calculation of the recoverable amount is sensitive to the assumptions regarding production volumes, discount rates and commodity prices.

The following commodity price estimates were used in determining whether an impairment to the carrying value of the CGUs existed at December 31, 2013:

	WTI Oil ($US/bbl)	***Henry HUB ($US/MMBtu)***
2014	97.50	4.25
2015	97.50	4.50
2016	97.50	4.75
2017	97.50	5.00
2018	97.50	5.25
2019	97.50	5.50
2020	98.54	5.63
2021	100.51	5.74
2022	102.52	5.86
2023	104.57	5.97
Thereafter	+2.0%/yr	+2.0%/yr

The following estimates were used in determining whether an impairment to the carrying value of the CGUs existed at December 31, 2012:

	WTI Oil ($US/bbl)	***NYMEX Gas ($US/MMBtu)***
2013	90.00	3.75
2014	92.50	4.25
2015	95.00	4.75
2016	97.50	5.25
2017	97.50	5.50
2018	97.50	5.80
2019	98.54	5.91
2020	100.51	6.03
2021	102.52	6.15
2022	104.57	6.27
Thereafter	+2.0%/yr	+2.0%/yr

20. Property, plant and equipment

$ 000's	Furniture, fixtures, and equipment	Computer equipment	Vehicles	Total
Cost				
At December 31, 2012	$ 60	$ 299	$ 81	$ 440
Additions	77	168	5	250
At December 31, 2013	$ 137	$ 467	$ 86	$ 690
Accumulated depreciation				
At December 31, 2012	$ (5)	$ (137)	$ (15)	$ (157)
Change for the period	(36)	(152)	(18)	(206)
At December 31, 2013	$ (41)	$ (289)	$ (33)	$ (363)
Net book value				
At December 31, 2012	$ 54	$ 162	$ 66	$ 282
Net change for the period	42	16	(13)	45
At December 31, 2013	$ 96	$ 178	$ 53	$ 327

$ 000's	Furniture, fixtures, and equipment	Computer equipment	Vehicles	Total
Cost				
At December 31, 2011	$ 11	$ 161	$ -	$ 172
Additions	49	138	81	268
At December 31, 2012	$ 60	$ 299	$ 81	$ 440
Accumulated depreciation				
At December 31, 2011	$ (1)	$ (44)	$ -	$ (45)
Change for the period	(4)	(93)	(15)	(112)
At December 31, 2012	$ (5)	$ (137)	$ (15)	$ (157)
Net book value				
At December 31, 2011	$ 10	$ 117	$ -	$ 127
Net change for the period	44	45	66	155
At December 31, 2012	$ 54	$ 162	$ 66	$ 282

The additions for 2013 consist predominantly of computer hardware used in the general and administrative environment.

21. Other intangible assets

$ 000's		December 31, 2013		December 31, 2012
Deferred financing charges	$	1,083	$	632
Accumulated amortization		(477)		(231)
Net other intangible assets	**$**	**606**	$	401

Deferred financing charges represent the upfront fees and related costs to establish and update the credit facility, see note 5 "Financial risk management" regarding liquidity and note 23 "Debt". The term of the facility per the signed term letter and credit facility agreement is May 31, 2015. The charges are being amortized over the life of the credit facility using the effective interest method.

22. Distributions payable

$ 000's		December 31, 2013		December 31, 2012		Cumulative
Beginning balance	$	2,570	$	1,656	$	-
Distributions declared		32,434		26,816		80,454
Less distributions paid		(32,191)		(25,902)		(77,641)
Outstanding distributions declared and payable	**$**	**2,813**	$	2,570	**$**	**2,813**

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

23. Debt

The subsidiary of the Trust may only borrow under the credit facility in U.S. dollars. The credit facility is a $US 350 million senior secured facility with a syndicate of Canadian chartered banks and is secured by a first priority security interest on substantially all of the oil and gas properties of Eagle Energy Acquisitions LP. Under the credit facility, Eagle Energy Trust, Eagle Energy Commercial Trust, Eagle Hydrocarbons LLC, Eagle Energy Inc. and Eagle Energy Acquisitions LP are required to satisfy certain customary affirmative and negative covenants (including financial covenants). The credit facility provides for customary negative covenants which, among other things, limit the Trust in making distributions to its unitholders if any default or event of default has occurred and is continuing or would result from such distribution, or if the cash distributions made in any quarter exceed the Trust's Available Distributable Cash Flow (as defined in the credit facility agreement) for the most recently completed quarter. The credit facility also includes other customary restrictive covenants including limitations on indebtedness, liens, contingent obligations, investments, dispositions, mergers, consolidations, liquidations and dissolutions and a negative pledge. In addition, a minimum current ratio (the ratio of current assets plus the unused commitment under the credit facility to current liabilities excluding any amounts owing under the credit facility) of not less than 1.00 to 1.00, a minimum coverage of interest expenses of not less than 3.00 to 1.00, and a maximum level of debt to earnings before interest, taxes and depreciation of 3.00 to 1.00 must be maintained. Failure to comply with any of these financial covenants, as well as any of the other affirmative and negative covenants, would result in an event of default. If not cured or waived, this would accelerate the debt repayment pursuant to the credit facility. At December 31, 2013 and December 31, 2012, there were no covenant violations. Total interest paid on debt as at December 31, 2013 was $2.1 million.

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

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

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

At December 31, 2012, details of the Trust's credit facility are as follows:

$000's	$US	$CA
Revolving	$ 48,500	$ 48,253
Total authorized	48,500	48,253
Less: Long-term debt	40,450	40,244
Available	**$ 8,050**	**$ 8,009**

The exchange rate in effect at December 31, 2012 was $US 1 equal to $CA 0.99.

Current debt (non-revolving)

Concurrent with the closing of the Hardeman Acquisition on November 25, 2013 (see note 7 "Acquisitions"), the subsidiary of the Trust entered into a $US 10 million non-revolving term credit facility with a maturity date of November 25, 2014, which is fully drawn.

The non-revolving credit facility allows for borrowing by way of LIBOR and base rate loans. The LIBOR and base rate margins are subject to a pricing grid based upon the percentage of credit facility utilization, and range from 3.0% to 4.0% and 2.0% to 3.0% respectively. For the period which the loan was outstanding during the year, the actual interest rate was 6.0% and interest paid on the non-revolving loan was $0.1 million.

Long-term debt (revolving)

The credit facility provides for a semi-annual evaluation each April 1 and October 1. Following the semi-annual review on October 1, 2013, the borrowing base for the revolving facility increased from $US 61 million to $US 70 million and the term extended to May 31, 2015. Concurrent with the closing of the Hardeman Acquisition on November 25, 2013 (see note 7 "Acquisitions"), the borrowing base for the revolving facility was increased from $US 70 million to $US 80 million.

As at December 31, 2013, $67.5 million has been drawn under this revolving $US 80 million credit facility by way of LIBOR and base rate loans. The LIBOR and base rate margins are subject to a pricing grid based upon the percentage of credit facility utilization, and range from 2.0% to 3.0% and 1.0% to 2.0%, respectively. For the period which the loan was outstanding during the year, the actual interest rate ranged from 4.8% to 5.0%. Interest paid during the year was $2.0 million.

24. Decommissioning liability

$000's	**December 31, 2013**	December 31, 2012
Beginning balance	$ 1,744	$ 502
Acquisition	672	709
Additions	191	666
Changes in estimates	315	(158)
Abandonment expenditures	(9)	-
Accretion (unwinding of discount)	61	25
Effects of foreign exchange rate	62	-
Ending balance	**$ 3,036**	$ 1,744

The decommissioning provision reflects the present value of internal estimates of future decommissioning costs of the Trust's net ownership position in oil and gas wells and related facilities at the relevant balance sheet date determined using local pricing conditions and requirements. These costs are expected to be incurred between 2015 and 2063. The timing of payments related to provisions is uncertain and is dependent on various items which are not always within Management's control.

The provision was estimated using existing technology, at current prices (adjusted for inflation assuming 2% inflation rate), and discounted using a risk-free discount rate of 3% (December 31, 2012 – 2%) for the Salt Flat properties, 3% for the Permian properties, (December 31, 2012 – 2.5%) and 3% for the Hardeman properties. A 1% decrease in the risk- free discount rate would have increased the liability by $617,305 as at December 31, 2013 (December 31, 2012 - $505,647).

Included in the balance at December 31, 2013 is $84,908 of decommissioning liability recorded as part of the 7.5% Permian Acquisition and $587,986 of decommissioning liability recorded as part of the Hardeman Acquisition see note 7 “Acquisitions”. The total undiscounted decommissioning liability at December 31, 2013 was $5.6 million (December 31, 2012 - $3.4 million).

25. Trust capital

Authorized

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

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

Trust units outstanding	**December 31, 2013**			December 31, 2012		
$000’s	**Number of units**		**Amount**	Number of units		Amount
Beginning balance	29,269	$	276,526	18,544	$	168,175
Issuance of Trust capital pursuant to DRIP	2,775		20,173	1,763		16,435
Issuance of Trust units(i)	-		-	8,680		95,480
Units released from escrow	105		859	282		2,779
Trust Unit issuance costs			(111)	-		(6,343)
Ending balance	**32,149**	**$**	**297,447**	29,269	$	276,526

(i) In conjunction with the asset acquisition which closed May 18, 2012.

For the year ended December 31, 2013, the Trust incurred $111,434 (December 31, 2012 - $261,368) of unit issuance costs in conjunction with the DRIP (as described below). The remaining $6,082,126 of unit issuance costs incurred in 2012 related to trust units issued for the May 18, 2012 asset acquisition.

DRIP Plan (Premium Distribution and Dividend Reinvestment Plan)

The DRIP plan (the “Plan”) provides eligible unitholders with the opportunity to reinvest their monthly cash distributions in new trust units at a 5% discount to the average market price (as defined in the plan) on the applicable distribution payment date. At the participant’s election, these new Trust units will either be credited to the participant’s account under the “distribution reinvestment component” of the Plan, or delivered to the designated Plan Broker in exchange for a premium cash payment to the participant equal to 102% of the reinvested distributions under the “premium distribution component” of the Plan. Participation in the Plan by unitholders is optional. Those unitholders who do not enroll in the Plan will still receive monthly cash distributions as declared by the Trust.

26. Cash generated from operations

$ 000's		Year Ended December 31, 2013		Year Ended December 31, 2012
Income (loss) for the period	$	4,914	$	6,117
Adjustments for:				
Depreciation, depletion and impairment		31,206		30,790
Unit-based compensation – non-cash portion		3,859		938
Unrealized risk management loss (gain)		3,675		(2,709)
Loss on disposal of assets		303		-
Finance expense		314		162
		44,271		35,298
Changes in working capital:				
Trade and other receivables		290		(2,177)
Prepaid expenses		(62)		(232)
Trade and other payables		(2,807)		1,428
		(2,579)		(981)
Cash (used in) generated from operations		41,692		34,317
Abandonment expenditures		(9)		(130)
Income taxes paid		-		-
Net cash generated by operating activities	**$**	**41,683**	$	34,187

Summary of non-cash items

$000's		Year Ended December 31, 2013		Year Ended December 31, 2012
Operating cash flow				
Unit-based compensation	$	3,859	$	939
Distributions payable – declared not yet paid		2,813		2,570
Unrealized risk management loss (gain)		3,675		(2,709)
Investment activities				
Depreciation, depletion and impairment		31,206		30,789
Loss on disposal of assets		303		-
Provision for decommissioning costs		1,233		1,217
Accretion of decommissioning provision		59		25
Financing activities				
Finance expense-amortization of deferred financing costs		254		135
Distributions accrued – declared not yet paid		(2,813)	$	(2,570)

27. Related party disclosures

The Trust has no party holding voting control.

Key management

Key management personnel includes the Trust's Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, Vice-President Business Development, Vice-President Finance, General Counsel/Corporate Secretary and the Directors. Refer to note 14 "Employees and key management".

Intercompany transactions

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

28. Commitments

Operating lease commitment – head office lease in Calgary, Alberta

On January 1, 2013, the Trust entered into a head-lease agreement for new office space which has an approximate 61 month term from January 8, 2013 to February 7, 2018. Future minimum lease payments during the term of the lease approximate $2.4 million and include leasehold improvements allowance of $0.3 million, with 49 months and approximately $1.9 million remaining at December 31, 2013.

Operating lease commitment – office lease in Houston, Texas

The lease agreement was entered into on April 1, 2011, and originally had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease agreement was extended for an additional 63 month period from October 1, 2013 to December 31, 2017 and the premise space was expanded to incorporate additional square footage. Future minimum lease payments during the term of the lease include an available leasehold improvement allowance of $US 111,293 and approximate $US 1.5 million, with 48 months and approximately $US 1.1 million remaining at December 31, 2013. 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 1.06.

Legal proceedings

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

29. Subsequent events

Commodity hedging

On January 27, 2014, the Trust entered into a financial contract to further mitigate the effects of fluctuating prices on a portion of its production as follows: a fixed contract to sell 190 barrels of oil per day with a January 2015 to December 2015 term at a price of $US 85.40 per barrel.

Foreign exchange hedging

On January 7, 2014, the Trust entered into a physical contract to mitigate the effects of foreign exchange rate ($CA/$US) fluctuations on monthly distribution payments as follows: a costless collar contract from January to December 2014 for an average of $922,000 per month at a floor of $CA 1.05 and a ceiling of $CA 1.09.

Acquisition

On February 27, 2014 the U.S. subsidiary of the Trust acquired undeveloped acreage and an average 66% working interest in producing properties in Hardeman County, Texas, and Greer, Harmon and Jackson Counties, Oklahoma for a net purchase price after preliminary adjustments at closing of $US 300,000, of $US 4.7 million. The acquisition, with an effective date of December 1, 2013, increases Eagle's recently established position in Hardeman County. The Trust used an advance under its credit facility to fund the acquisition.

Corporate Information

Board of Directors

David M. Fitzpatrick
Chairman of the Board

Bruce K. Gibson (1)
Director

Warren D. Steckley (2)
Director

Joseph W. Blandford (3)
Director

Richard W. Clark
President, Chief Executive Officer and Director

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

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Officers

Richard W. Clark
President, Chief Executive Officer and Director

Kelly A. Tomyn
Chief Financial Officer

J. Wayne Wisniewski
Chief Operating Officer

Robert J. Cunningham
Vice President, Business Development

James D. Elliott
Vice President, Finance

Jo-Anne M. Bund
General Counsel/Corporate Secretary

Auditors

PricewaterhouseCoopers LLC

Trustee and Transfer Agent

Computershare Trust Company of Canada

Engineering Consultants

Netherland Sewell and Associates, Inc.

Bankers

Bank of Nova Scotia

Legal Counsel

Bennett Jones LLP

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