Eagle Energy Trust

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

For the three and nine months ended September 30, 2012

Eagle Energy Trust

Condensed Consolidated Balance Sheets

(Thousands of Canadian dollars) (unaudited)

	Note	September 30, 2012	December 31, 2011
ASSETS			
Current assets			
Cash		$ 5,053	$ 7,495
Trade and other receivables		7,399	5,585
Prepaid expenses		459	305
Risk management asset	3	1,298	-
		14,209	**13,385**
Non-current assets			
Risk management asset	3	667	-
Exploration and evaluation		302	119
Oil and gas properties	11	268,147	145,067
Property, plant and equipment		186	127
Other intangible assets	12	402	187
		269,704	**145,500**
Total Assets		**$ 283,913**	**$ 158,885**
LIABILITIES			
Current liabilities			
Trade and other payables		10,929	5,926
Distributions payable	13	2,519	1,656
Unit-based payments	7	10,275	8,472
Risk management liability	3	-	503
		23,723	**16,557**
Non-current liabilities			
Long - term debt	14	33,429	-
Deferred income tax	9	-	-
Provision for liabilities and other charges		1,706	502
		35,136	**502**
Total Liabilities		**$ 58,858**	**$ 17,059**
UNITHOLDERS' EQUITY			
Trust capital	15	271,589	168,175
Other reserves		(8,260)	(718)
Accumulated earnings (loss)		2,093	(4,427)
Accumulated cash distributions	13	(40,367)	(21,204)
Total Unitholders' Equity		**225,055**	**141,826**
Total Liabilities and Unitholders' Equity		**$ 283,913**	**$ 158,885**

See Note 18 "Commitments".
The notes are an integral part of these condensed financial statements.

Eagle Energy Trust

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

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

	Note	**Three Months Ended September 30, 2012**	Three Months Ended September 30, 2011	**Nine Months Ended September 30, 2012**	Nine Months Ended September 30, 2011
Revenue	5	$ 15,181	$ 5,533	$ 42,205	$ 19,973
Cost of sales	6	9,775	3,722	26,890	11,466
Gross profit		5,406	1,811	15,315	8,507
Administrative expenses		1,316	1,489	5,414	3,973
Unit - based compensation expense	7	2,332	871	5,330	5,776
Operating profit (loss)		**1,758**	**(549)**	**4,571**	**(1,242)**
Foreign exchange gain (loss), net		68	(279)	217	340
Finance expense	8	(509)	(46)	(712)	(114)
Risk management gain (loss)	3	(3,827)	1,295	2,445	1,229
Earnings (Loss) before taxes		**(2,510)**	**421**	**6,521**	**213**
Income tax recovery – deferred	9	(1,415)	-	-	-
Earnings (Loss)		**$ (1,095)**	**$ 421**	**$ 6,521**	**$ 213**
Other comprehensive income (loss)					
Foreign currency translation gain (loss)		(9,313)	13,027	(7,542)	8,488
Comprehensive income (loss)		**$ (10,408)**	$ 13,448	**$ (1,021)**	$ **8,701**
Earnings (Loss) per unit					
Basic	10	(0.04)	0.02	0.28	0.01
Diluted	10	(0.04)	0.02	0.28	0.01

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

Eagle Energy Trust

Condensed Consolidated Statements of Unitholders' Equity

For the nine months ended September 30, 2012 and year ended December 31, 2011
(Thousands of Canadian dollars) (unaudited)

	Note	Number of Trust Units	Trust capital	Currency reserve	Accumulated earnings(loss)	Accumulated cash distributions	Deficit	Total Unitholders equity
Balance as at December 31, 2010		**17,624**	**159,577**	**(4,366)**	**(3,214)**	**(1,916)**	**(5,130)**	**150,081**
Earnings		-	-	-	213	-	213	213
Foreign currency translation gain		-	-	8,488	-	-	-	8,488
Comprehensive income		-	-	8,488	213	-	213	8,701
Issuance of Trust capital		550	5,766	-	-	-	-	5,766
Trust unit issuance costs		-	(412)	-	-	-	-	(412)
Unitholder distributions		-	-	-	-	(14,351)	(14,351)	(14,351)
		550	5,354	-	-	(14,351)	(14,351)	(8,997)
Balance as at September 30, 2011		**18,174**	**164,931**	**4,122**	**(3,001)**	**(16,267)**	**(19,268)**	**149,785**
Balance as at December 31, 2011		**18,544**	**168,175**	**(718)**	**(4,427)**	**(21,204)**	**(25,631)**	**141,826**
Earnings		-	-	-	6,521	-	6,521	6,521
Foreign currency translation loss		-	-	(7,542)	-	-	-	(7,542)
Comprehensive income		-	-	(7,542)	6,521	-	6,521	(1,021)
Issuance of Trust capital	15	10,110	109,524	-	-	-	-	109,524
Trust unit issuance costs	15	-	(6,110)	-	-	-	-	(6,110)
Unitholder distributions	13	-	-	-	-	(19,163)	(19,163)	(19,163)
		10,110	103,414	-	-	(19,163)	(19,163)	84,250
Balance as at September 30, 2012		28,654	271,589	(8,260)	2,093	(40,367)	(38,274)	225,055

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

Eagle Energy Trust

Condensed Consolidated Cash Flow Statements

(Thousands of Canadian dollars) (unaudited)

	Note	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Cash flows from operating activities					
Net cash generated by operating activities	16	**$ 4,218**	$ **3,062**	**$ 27,514**	$ **8,064**
Cash flows from investing activities					
Additions to exploration and evaluation		(99)	(265)	(183)	(587)
Additions to oil and gas properties		(15,664)	(11,257)	(32,000)	(23,655)
Additions to property, plant and equipment		(45)	(57)	(145)	(117)
Acquisition of oil and gas assets	4	(222)	-	(115,902)	-
Net cash used in investing activities		**$ (16,030)**	$ **(11,579)**	**$ (148,230)**	$ **(24,359)**
Cash flows from financing activities					
Long-term debt		10,404	-	34,343	-
Proceeds from issuance of units		4,654	2,839	106,956	5,766
Trust unit issue costs		(170)	(209)	(6,110)	(412)
Cash distributions to unitholders		(7,468)	(4,823)	(18,301)	(14,643)
Change in non-cash working capital		2,568	-	2,568	-
Deferred financing charges		(3)	-	(258)	-
Net cash provided by (used in) financing activities		**$ 9,985**	$ **(2,193)**	**$ 119,198**	$ **(9,289)**
Net (decrease) increase in cash and cash equivalents		**(1,827)**	**(10,710)**	**(1,518)**	**(25,584)**
Effects of exchange rates on cash and cash equivalents		(1,767)	2,427	(924)	1,632
Cash at beginning of the period		8,647	16,062	7,495	31,731
Cash at end of the period		**$ 5,053**	$ **7,779**	**$ 5,053**	$ **7,779**

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

Eagle Energy Trust

Notes to Condensed Consolidated Financial Statements (unaudited)

For the nine months ended September 30, 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 and was settled with a 1/10 ounce gold coin and $200 from the initial unitholders. The beneficiaries of Eagle Energy Trust are the unitholders.

Throughout these notes to the condensed consolidated financial statements, Eagle Energy Trust and its subsidiaries are referred to collectively as the "Trust" or "Eagle" for purposes of convenience.

The strategy of the Trust is to invest in operating subsidiaries that will acquire on-shore petroleum reserves and production in certain regions of 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 the Trust's initial acquisition.

The address of the Trust is: 9^{th} Floor, 639-5^{th} Avenue SW, Calgary, AB T2P 0M9.

2. Basis of preparation

Basis of accounting

The condensed consolidated financial statements were authorized for issue in accordance with a resolution of the Board of Directors made on November 7, 2012.

These condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including IAS 34, Interim Financial Reporting and have been prepared following the same accounting policies as the annual audited IFRS Consolidated Financial Statements for the year ended December 31, 2011, except for income tax expense for an interim period which is based on an estimated average annual effective income tax rate. The condensed consolidated interim financial statements should be read in conjunction with the annual financial statements for the year ended December 31, 2011, which have been prepared in accordance with IFRS as issued by the IASB.

3. Financial risk management

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

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

This note presents information about significant changes in the Trust's exposure to each of the above risks since the year ended December 31, 2011.

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 various factors such as the relationship between the Canadian and United States dollars and 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 usually 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. The Trust, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts.

As at September 30, 2012, the Trust has the following financial contracts outstanding to mitigate the effects of fluctuating prices on a portion of its production:

1. A fixed contract to sell 200 bbls of oil per day with a November 2011 through October 2012 term at a price of $US 91.00 per barrel.

2. A costless collar contract for 500 bbls of oil per day with a January 2012 through December 2012 term at a floor of $US 92.00 per barrel and a ceiling of $US 105.00 per barrel.

3. A costless collar contract for 300 bbls of oil per day with a May 2012 through April 2013 term at a floor of $US 95.00 per barrel and a ceiling of $US 108.25 per barrel

4. A fixed contract to sell 200 bbls of oil per day with a January 2013 through April 2013 term and 500 bbls of oil per day with a May 2013 through December 2013 term, at a price of $US 103.45 per barrel.

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

6. A costless collar contract for 250 bbls of oil per day with an August 2012 through July 2013 term at a floor of $US 87.00 per barrel and a ceiling of $US 89.70 per barrel.

7. A costless collar contract for 250 bbls of oil per day with a September 2012 through August 2013 term at a floor of $US 90.00 and a ceiling of $US 91.60 per barrel.

8. A costless collar contract with a floor of $US 95.00 and a ceiling of $US 103.75 per barrel for the following volumes and terms: 200 bbls of oil per day with a November 2012 through December 2012 term, 300 bbls of oil per day with a January 2013 through July 2013 term, 500 bbls of oil per day with an August 1 to 31, 2013 term, and 800 bbls of oil per day with a September 2013 through December 2013 term.

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

Summary of Unrealized Risk Management Positions as at September 30, 2012

	Volume	*Measure*	*Beginning*	*Term*	*Floor $US*	*Ceiling $US*	*Current Fair Value $000's*	*Non-Current Fair Value $000's*
Oil Fixed Price								
NYMEX (i)	200	bbls/d	Nov-11	Oct-12	91.00	91.00	(30)	
NYMEX (ii)	500	bbls/d	Jan-12	Dec-12	92.00	105.00	124	
NYMEX (ii)	300	bbls/d	May-12	Apr-13	95.00	108.25	331	
NYMEX (i)	200	bbls/d	Jan-13	Apr-13	103.45	103.45	231	
NYMEX (i)	500	bbls/d	May-13	Dec-13	103.45	103.45	735	471
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	98.00	98.00	-	949
NYMEX (ii)	250	bbls/d	Aug-12	Jul-13	87.00	89.70	(400)	
NYMEX (ii)	250	bbls/d	Sept-12	Aug-13	90.00	91.60	(243)	
NYMEX (ii)	200	bbls/d	Nov-12	Dec-12	95.00	103.75	55	
NYMEX (ii)	300	bbls/d	Jan-13	Jul-13	95.00	103.75	295	
NYMEX (ii)	500	bbls/d	Aug-13	Aug-13	95.00	103.75	77	
NYMEX (ii)	800	bbls/d	Sep-13	Dec-13	95.00	103.75	123	399
NYMEX (iii)	500	bbls/d	Jan-14	Dec-14	100.00	100.00	-	(1,152)
							$ 1,298	**$ 667**

(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).

Earnings Impact of Realized and Unrealized Gain (Loss)

	Three Months Ended September 30, 2012			**Three Months Ended September 30, 2011**		
$000's	Realized Gain (Loss) September 30, 2012	Unrealized Gain (Loss) September 30, 2012	Total Net Gain (Loss) September 30, 2012	Realized Gain (Loss) September 30, 2011	Unrealized Gain (Loss) September 30, 2011	Total Net Gain (Loss) September 30, 2011
Net effect - risk management	**$ 26**	**$ (3,853)**	**$ (3,827)**	**$ 124**	**$ 1,171**	**$ 1,295**

	Nine Months Ended September 30, 2012			**Nine Months Ended September 30, 2011**		
$000's	Realized Gain (Loss) September 30, 2012	Unrealized Gain (Loss) September 30, 2012	Total Net Gain (Loss) September 30, 2012	Realized Gain (Loss) September 30, 2011	Unrealized Gain (Loss) September 30, 2011	Total Net Gain (Loss) September 30, 2011
Net effect - risk management	**$ (23)**	**$ 2,468**	**$ 2,445**	**$ 52**	**$ 1,177**	**$ 1,229**

4. Acquisition

On May 18, 2012, Eagle acquired 92.5% of the seller's 99% interest in certain Permian Basin oil and natural gas properties and related assets, located near Midland, Texas for total cash consideration of $115,901,909, which includes closing adjustments of $1,387,187. The acquisition had an effective date of April 1, 2012 and a closing date of May 18, 2012. Included in administrative expenses for the nine months ended September 30, 2012 is $1,514,547 of transaction costs relating to this acquisition.

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	$	116,611
Decommissioning liabilities		(709)
	$	**115,902**

The acquisition agreement provides Eagle with the right and obligation to purchase all of the seller's remaining undivided 7.5% interest in the properties by no later than April 30, 2013 on similar terms and conditions as the acquisition. Refer to note 18 "Commitments".

5. Operating segments

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

Geographical information

The Trust's operational activities are wholly focused in the continental United States, currently in the state of Texas, and are supported by offices in Houston and Luling, Texas. Pursuant to the acquisition described in note 4, an office will also be established in Midland, Texas. The Trust's head office is in Calgary, Alberta. All inter-segment and geographical transactions have been eliminated in consolidation.

Revenue

All of the Trust's revenue is derived from its operations in the United States. Revenue is presented net of royalties as noted in the following table.

$000's	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenue before royalties	$ 20,742	$ 7,652	58,257	$ 27,640
Royalties	(5,561)	(2,119)	(16,052)	(7,667)
	$ 15,181	**$ 5,533**	**42,205**	**$ 19,973**

Non-Current assets

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

6. Cost of sales

$000's	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating costs related to the field	$ 3,581	$ 1,451	10,060	$ 3,722
Depreciation, depletion and amortization	6,194	2,271	16,830	7,744
	$ 9,775	**$ 3,722**	**26,890**	**$ 11,466**

7. Unit-based payments

The following table reconciles unit-based compensation expense.

$000's	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	
Units issued on performance option surrender	$ 546	$ 289	$ 1,280	$ 1,454	Note 7 (a)
Restricted unit rights	612	254	1,519	1,701	Note 7 (b)
Unit options	1,006	242	2,211	2,519	Note 7 (c)
Unit rights	167	86	320	102	Note 7 (d)
Unit-based compensation expense	**$ 2,332**	**$ 871**	**$ 5,330**	**$ 5,776**	

Note (a)

Units issued upon surrender of performance options

At September 30, 2012, 129,167 escrowed units were outstanding (December 31, 2011 and September 30, 2011 - 387,500).

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 will be released from escrow on September 14, 2013. The fair value estimate associated with the escrowed units is expensed in the income statement over the escrow period which is the same period as the performance conditions, with the offsetting entry to either trade and other payables or other long term liabilities.

At December 31, 2011, $2,130,821 (December 31, 2010 - $nil) was included in unit based payments and $nil (December 31, 2010 - $205,905) was included in other long-term liabilities relating to these escrowed units. Upon release from escrow, the related accumulated liability will be transferred to the trust capital account in unitholders' equity. On September 14, 2012, 258,333 units were released from escrow with an associated value of $2,567,830 being transferred from the accumulated liability to the trust capital account in unitholder's equity.

At September 30, 2012, $843,511 (December 31, 2011 – $2,130,831, September 30, 2011 - $1,245,007) was included in unit based payments and $nil (December 31, 2011 - $nil, September 30, 2011 - $415,004) was included in other long-term liabilities relating to these units remaining in escrow.

$000's	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Balance, beginning of period	387,500	387,500
Issued	-	-
Transferred to the Trust capital account	(258,333)	-
Balance, end of period	129,167	387,500
Number of units in escrow	129,167	387,500

At September 30, 2012, the fair value of the units was assumed to be equal to the September 30, 2012 closing price of $10.09 per unit (December 31, 2011 - $10.05 per unit, September 30, 2011 - $9.72 per unit).

Note (b)

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

At September 30, 2012, December 31, 2011 and September 30, 2011, there were 775,000 RURs outstanding.

As at September 14, 2012, two-thirds of the RUR's vested. Vested amounts up to September 30, 2012 of $958,925 were paid to the RUR holders.

At September 30, 2012, $2,930,035 (December 31, 2011 - $2,370,407, September 30, 2011 - $1,398,715) was included in unit based payments and $nil (December 31, 2011 - $nil, September 30, 2011 – $446,237) was included in other long term liabilities relating to these RURs.

At September 30, 2012, the Black-Scholes valuation model was used to determine the fair value of the RURs issued by the Trust. The fair value of the RURs was estimated using the following inputs:

	September 30, 2012	December 31, 2011	September 30, 2011
Fair value at the balance sheet date	$ 5.91	$ 5.59	$ 5.46
Volatility	32%	35%	34%
Life of restricted unit rights	8.3 years	9.0 years	9.3 years
Risk-free interest rate	1.80%	1.98%	2.2%

A forfeiture rate of 5% was used and, due to the limited history of the Trust, this figure is an estimated expected rate.

Note (c)

Unit option plan

At September 30, 2012, there were 2,433,000 (December 31, 2011–1,706,000) options outstanding. The weighted average exercise price at September 30, 2012 was $8.52 per option (December 31, 2011 - $8.88 per option). At September 30, 2011, there were 1,347,500 options outstanding with a weighted average exercise price of $9.24.

At September 30, 2012, $5,963,684 (December 31, 2011 - $3,801,767, September 30, 2011 - $1,539,591) was included in unit based payments and $nil (December 31, 2011 - $nil, September 30, 2011 - $1,282,993) was included in other long-term liabilities relating to this option plan.

The closing trading price of the Trust's units at September 30, 2012 was $10.09 per unit (December 31, 2011 - $10.05 per unit, September 30, 2011 - $9.72 per unit). At September 30, 2012, the Black-Scholes valuation model was used to determine the fair value of the options issued by the Trust. The fair value of the options was estimated using the following inputs:

	September 30, 2012	December 31, 2011	September 30, 2011
Fair value at the balance sheet date	$ 4.63	$ 4.73	$ 4.31
Unit price	$ 10.09	$ 10.05	$ 9.72
Exercise price	$ 8.52	$ 8.88	$ 9.24
Volatility	32%	35%	34%
Option life	8.8 years	9.1 years	9.2 years
Distributions – none estimated, declining strike price feature	0%	0%	0%
Risk-free interest rate	1.80%	1.98%	2.2%

A forfeiture rate of 5% was used and due to the limited history of the Trust, this figure is an estimated expected rate. This estimate will be adjusted to the actual forfeiture rate.

Note (d)

Unit rights (URP) plan

At September 30, 2012, there were 493,000 (December 31, 2011 – 185,000; September 30, 2011 – 130,000) unit rights outstanding. At September 30, 2011, there were 130,000 unit rights outstanding, since the plan was implemented June 14, 2011.

At September 30, 2012, $537,850 (December 31, 2011 - $217,620, September 30, 2011 - $55,387) was included in unit based payments and $nil (December 31, 2011 - $nil, September 30, 2011 - $46,154) was included in other long-term liabilities relating to the URP plan.

At September 30, 2012, the Black-Scholes valuation model is used to determine the fair value of the URPs issued by the Trust. The fair value of the URPs was estimated using the following weighted average inputs:

	September 30, 2012	December 31, 2011	September 30, 2011
Fair value at the balance sheet date	$ 4.62	$ 4.76	$ 4.41
Volatility	32%	35%	34%
Life of restricted unit rights	9.5 years	9.5 years	9.6 years
Risk-free interest rate	1.80%	1.98%	2.2%

A forfeiture rate of 5% was used and, due to the limited history of the Trust, this figure is an estimated expected rate.

8. Finance expense

$000's	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Interest expense on long-term debt	$ 383	$ -	$ 570	$ -
Amortized application fees on long-term debt	94	24	42	61
Standby and bank fees	24	19	83	45
Accretion of decommissioning provision	8	3	17	8
Finance expense	$ 509	$ 46	$ 712	$ 114

9. Deferred income tax

Reconciliation of effective tax rate

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

$ 000's		Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Earnings (loss) before taxes		$ (2,510)	$ 421	$ 6,521	$ 213
Expected tax rate		35%	35%	35%	35%
Expected income tax expense (recovery)		(878)	147	2,282	(74)
Increase (Decrease) resulting from:					
Non-deductible items – permanent differences					
Administrative expenses of the Trust	35%	174	147	518	577
Unit-based compensation (recovery)	35%	816	305	1,865	2,022
Foreign exchange gain, net	35%	52	(97)	-	(119)
Risk management gain (loss)	35%	2,195	(453)	-	(430)
Changes in temporary differences for which no amounts are recognized	35%	(3,025)	688	(1,601)	652
Changes in temporary difference for which amounts are recognized	35%	637	-	374	-
Items deductible at the subsidiary level					
Interest on internal debt of subsidiary	35%	(1,394)	(940)	(3,462)	(2,789)
Other	35%	18	9	24	13
Income tax recovery	35%	$ (1,415)	$ -	$ -	$ -

Deferred tax assets and liabilities:

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

$ 000's	September 30, 2012	December 31, 2011
Deferred tax liabilities:		
Oil and gas properties in excess of tax value	$ 17,677	$ 13,118
Exploration and evaluation assets	-	-
	17,677	13,118
Less deferred tax assets:		
Non-capital losses – US based	(18,051)	(14,138)
Net deferred tax liability (asset) – before valuation allowance	(374)	(1,020)
Valuation allowance[1]	374	1,020
Net deferred tax liability (asset)	$ -	$ -

(1) The asset is not recognized because the future recoverability is not certain.

10. Earnings (Loss) per unit

$000's	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Earnings (Loss) - basic	$ (1,095)	$ 421	$ 6,521	$ 213
Earnings (Loss) - diluted	$ (1,095)	$ 421	$ 6,521	$ 213
Weighted average units outstanding - basic	28,156	18,011	23,276	17,793
Weighted average units outstanding - diluted	28,156	18,011	23,276	17,793
Earnings (Loss) per unit - basic	**$ (0.04)**	**$ 0.02**	**$ 0.28**	**$ 0.01**
Earnings (Loss) per unit - diluted	**$ (0.04)**	**$ 0.02**	**$ 0.28**	**$ 0.01**

Calculation

Basic earnings (loss) per unit is calculated by dividing the earnings (loss) attributable to unitholders of the Trust by the weighted average number of units outstanding during the period. Diluted earnings (loss) per unit is calculated using the earnings (loss) for the period, adjusted for anti-dilutive items, divided by the weighted average number of units outstanding assuming the conversion of potentially dilutive equity instruments outstanding.

Per unit amounts

Excluded from the three and nine months ended September 30, 2012 and September 30, 2011 trust units outstanding are 2,433,000 (September 30, 2011 – 1,342,500) options as well as 129,167 trust units remaining in escrow because they are anti-dilutive. Refer to note 7, "Unit-based payments".

11. Oil and gas properties

$000's	Developed oil & 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	134,916	3,808	1,188	139,911
Transfers from exploration and evaluation	-	-	-	-
At September 30, 2012	**$ 289,281**	**$ 7,164**	**$ 1,679**	**$ 298,123**
Accumulated depreciation				
At December 31, 2011	$ (12,555)	$ (590)	$ -	$ (13,145)
Charge for the period	(15,358)	(1,473)	-	(16,831)
At September 30, 2012	**$ (27,913)**	**$ (2,063)**	**$ -**	**$ (29,976)**
Net book value				
At December 31, 2011	$ 141,810	$ 2,766	$ 491	$ 145,067
Net change	119,558	2,335	1,188	123,080
At September 30, 2012	**$ 261,368**	**$ 5,101**	**$ 1,679**	**$ 268,147**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $121,262,487 (December 31, 2011 - $54,982,000) were included in the depletion calculation. Additions to “Developed oil & gas assets “ includes the acquisition which closed on May 18, 2012, see note 4 “Acquisition”.

12. Other intangible assets

$000's	**September 30, 2012**	December 31, 2011
Deferred financing charges	$ 545	$ 289
Accumulated amortization	(143)	(102)
Net other intangible assets	$ **402**	$ **187**

Deferred financing charges represent the upfront fees and related costs to establish and update the credit facility, see note 14 “Long-term debt”. The term of the credit facility is three years, to November 24, 2013.

13. Distributions payable

$000's	**September 30, 2012**	December 31, 2011	Cumulative
Beginning balance	$ 1,656	$ 1,916	$ -
Distributions declared	19,162	19,287	40,367
Less distributions paid	(18,301)	(19,547)	37,848
Outstanding distributions declared and payable	**$ 2,519**	$ 1,656	**$ 2,519**

Distributions are declared and paid monthly. The outstanding balance at September 30, 2012 represents the distribution declared September 17, 2012 and paid October 23, 2012. The outstanding balance at December 31, 2011 represents the distribution declared December 15, 2011 and paid January 23, 2012.

14. Long-term debt

On November 24, 2010, Eagle Energy Acquisitions LP entered into a credit facility with a U.S. affiliate of a Canadian chartered bank. The credit facility provides for a semi-annual evaluation each April 1 and October 1. In conjunction with the closing of the acquisition on May 18, 2012, (see note 4 “Acquisition”) the borrowing base was increased to $US 48.5 million from $US 31 million. The October 1, 2012 semi-annual review reaffirmed the $US 48.5 million borrowing base.

As at September 30, 2012, $33,428,800 has been drawn under this $US 48.5 million credit facility by way of base rate loans. Borrowings will be either by way of a LIBOR or base rate option. The LIBOR and base rate margins above LIBOR or the base rate, as applicable, will be subject to a pricing grid based upon the percentage of utilization of the borrowing base, which range from 2.25% to 3.00% and 1.25% to 2.00%, respectively. For the period which the loan was outstanding during the quarter, the actual interest rate ranged from 4.5% to 5.0%. Eagle Energy Acquisitions LP may only borrow under the credit facility in U.S. dollars. The credit facility is a $US 150 million three year senior secured revolving facility 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 from making distributions of cash flow to its unitholders if any default or event of default has occurred and is continuing or would result from such distribution, or if more than 90% of the lesser of the borrowing base or total commitments under the credit facility has been utilized. 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 September 30, 2012 there were no covenant violations.

15. Trust capital

Trust units outstanding	**September 30, 2012**			**December 31, 2011**		
$000's	**Number of units (000's)**		**Amount $000's**	**Number of units (000's)**		**Amount $000's**
Beginning balance	18,544	$	168,175	17,624	$	159,577
Issuance of Trust units pursuant to DRIP	1,172		11,476	920		8,961
Issuance of Trust units [(1)]	8,680		95,480	-		-
Reclassification from unit based compensation for option exercise	-		-	-		49
Units released from escrow	258		2,568	-		-
Trust unit issuance costs	-		(6,110)	-		(412)
Ending balance	**28,654**	**$**	**271,589**	**18,544**	$	**168,175**

(1) In conjunction with the asset acquisition which closed May 18 (see note 4 “Acquisition”), the Trust closed a bought deal financing of 7,730,000 trust units at a price of $ 11.00 per trust unit, for aggregate gross proceeds of $85,030,000. In addition, the Underwriters were granted an over-allotment option, and purchased an additional 950,000 trust units on May 29, 2012 for additional proceeds of $10,450,000.

Trust units issued, but not classified as outstanding

Refer to note 7 “Unit-based payments”. The 129,167 units issued to certain directors, management and a consultant on the surrender of previously granted performance options and escrowed have been excluded from units outstanding as a result of IFRS principles which exclude escrowed units due to the performance conditions that have to be met in order for the units to be released from escrow.

16. Cash generated from operations

$000's	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Income (loss) for the period	**$ (1,095)**	$ 421	**$ 6,521**	$ 213
Adjustments for:				
Depreciation, depletion and amortization	6,221	2,284	16,906	7,772
Income tax recovery - deferred	(1,415)	-	-	-
Unit-based compensation – non-cash portion	1,373	871	4,371	5,776
Unrealized risk management loss (gain)	3,853	(1,171)	(2,468)	(1,177)
Finance expense	102	27	60	69
	9,039	2,432	**25,390**	12,653
Changes in non-cash working capital:				
Trade and other receivables	(626)	(702)	(2,034)	(3,176)
Prepaid expenses	(322)	(203)	(166)	(300)
Trade and other payables	(3,873)	1,535	4,324	(1,113)
	(4,821)	630	**2,124**	(4,589)
Cash generated from operations	4,218	3,062	27,514	8,064
Income taxes paid	-	-	-	-
Net cash generated by operating activities	**$ 4,218**	$ 3,062	**$ 27,514**	$ 8,064

Summary of non-cash items

$000's	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating cash flow				
Income tax recovery - deferred	$ (1,415)	-	$ -	-
Unit-based compensation	1,373	871	4,371	5,776
Distributions payable-declared not yet paid	2,519	1,624	2,519	1,624
Unrealized risk management loss (gain)	3,853	(1,171)	(2,468)	(1,177)
Investment activities				
Depreciation, depletion and amortization	$ 6,221	$ 2,284	$ 16,906	$ 7,772
Provision for decommissioning costs	81	124	1,188	235
Accretion of decommissioning provision	8	3	17	8
Financing activities				
Finance expense-amortization of deferred financing costs	$ 94	$ 24	$ 44	$ 61
Distributions accrued-declared not yet paid	(2,519)	(1,624)	(2,519)	(1,624)

17. Related party disclosures

The Trust has no party holding voting control.

Key management personnel

Key management personnel consist of the Chief Executive Officer, Chief Operating Officer, Chief Financial Officer and the Directors.

Intercompany transactions

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

Head office lease in Calgary, Alberta

The Trust subleases office space along with furniture and equipment from a company of which a director of the Administrator of the Trust is the President and Chief Operating Officer. The terms of the agreement are recorded at the exchange amount. The monthly rent rate is $8,500, which approximates market value. Refer to note 18, “Commitments” regarding operating lease commitments.

No amounts were owing to this related party as at September 30, 2012 and December 31, 2011. For the nine months ended September 30, 2012 administrative expenses included $76,500 (September 30, 2011 - $73,500) for amounts billed from this related party.

18. Commitments

Operating lease commitment – head office lease in Calgary, Alberta

The initial term of the sublease agreement was for six months from January 1, 2011 until June 30, 2011. On July 25th, 2011, the sublease agreement was renewed for an additional 6 month period from August 1, 2011 to January 31, 2012 with a monthly rent rate of $8,500. Thereafter, the agreement automatically rolls over on a monthly basis, unless either party serves a 30 day notice of termination. Therefore, the agreement is cancellable any time after the end of the term if notice is provided. Future minimum lease payments during the additional six month term of the sublease were $51,000, with $nil remaining as at September 30, 2012.

Operating lease commitment – office lease in Houston, Texas

The agreement was entered into on April 1, 2011, and has an approximate 30 month term from April 7, 2011 through September 30, 2013. Future minimum lease payments during the term of the sublease approximate $US 338,400, with 12 months and approximately $US 135,000 remaining at September 30, 2012. In $CA the remaining future minimum lease payments approximate $133,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9832.

Operating lease commitment – office lease in Luling, Texas

The agreement was entered into on August 15, 2011, and originally had an approximate 12 month term from August 15, 2011 through August 31, 2012. On April 24, 2012, the lease agreement was extended for an additional 36 month period from September 1, 2012 to August 31, 2015 with a monthly rate of $1,650. Future minimum payments during the term of the sublease and the extension approximate $US 80,000, with $US 58,000 remaining at September 30, 2012. In $CA, the remaining future minimum lease payments approximate $57,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9832.

Operating lease commitment – office lease in Midland, Texas

The agreement was entered into on July 31, 2012 and has an approximate 48 month term from October 15, 2012 through October 14, 2016. Future minimum lease payments during the term of the lease approximate $US 203,000. In $CA the future minimum lease payments approximate $199,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9832.

Drilling rig commitment – six wells

Eagle, through its operations in the Permian Basin, (see note 4, "Acquisition") entered into a six well drilling rig commitment agreement effective July 23, 2012. At September 30, 2012, three wells have been drilled under the agreement. Future minimum payments are estimated to be approximately $US 3.4 million, which is 100% of the commitment. The net commitment to Eagle based upon its approximate 92.5% interest equates to $US 3.1 million with approximately $US 1.7 million remaining at September 30, 2012. In $CA the net future commitment approximates $1.5 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 0.9832.

Drilling rig commitment – eight wells

Eagle, through its operations in the Salt Flat Field, amended its existing nine well drilling rig commitment agreement to include an additional eight wells effective July 27, 2012. At September 30, 2012, five of the additional eight wells have been drilled. Future minimum payments for the eight additional wells are estimated to be approximately $US 1.4 million, which is 100% of the commitment. The net commitment to Eagle based upon its approximate 80% interest equates to $US 1.1 million with approximately $US 545,000 remaining at September 30, 2012. In $CA the remaining net future commitment approximates $430,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 0.9832.

Acquisition - Non-financial forward purchase contract

The acquisition agreement dated May 18, 2012 (refer to note 4, "Acquisition") provides Eagle with the right and obligation to purchase all of the seller's remaining undivided 7.5% interest in the properties by no later than April 30, 2013 on similar terms and conditions as the acquisition. The purchase price to be paid by Eagle for the remainder of the assets on the closing of such purchase will be determined by a formula based on the net present value of such assets as of January 1, 2013, as determined in an independent engineering report which is intended to approximate the fair market value at that time. The acquisition agreement restricts (other than ordinary course sales) the seller from, indirectly or directly, soliciting, negotiating or taking any other actions or steps in respect of a sale or possible sale of the remainder assets to any third party prior to April 30, 2013.

Management's Discussion and Analysis

November 7, 2012

This Management's Discussion and Analysis ("**MD&A**") of financial condition and results of operations for Eagle Energy Trust (the "**Trust**"), dated November 7, 2012, should be read in conjunction with the unaudited interim condensed consolidated financial statements and accompanying notes for the period ended September 30, 2012 ("**Interim Financial Statements**") and the Trust's audited consolidated financial statements and accompanying notes and related MD&A for the year ended December 31, 2011 and the Trust's Annual Information Form dated March 22, 2012 ("**AIF**"), which are available online at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

The Interim Financial Statements have been prepared in accordance with IAS 34 *Interim Financial Reporting*. Items included in the financial statements of each of the Trust's subsidiaries are measured using the currency of the primary economic environment in which the entity operates (the "**functional currency**"). The Interim Financial Statements are presented in Canadian dollars, which is the functional and presentation currency of the Trust.

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, Eagle Energy Acquisitions LP ("**Eagle**").

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 International Financial Reporting Standards (**"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. Field netback is calculated by subtracting royalties and operating costs from revenues. 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 in south central Texas. 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, located near Midland, Texas. After the closing, Eagle also acquired all of another party's 1% interest in the same properties.

Highlights for the three month period ended September 30, 2012

- Achieved average working interest sales volumes of 2,825 boe/d, (95% oil and natural gas liquids) which represents a 184% increase from the comparable 2011 quarter and an 18% increase from the second quarter of 2012.

- Recorded funds flow from operations of $9.0 million ($34.78 per boe or $0.32 per unit), which represents a 272% increase from the comparable 2011 quarter and a 25% increase from the second quarter of 2012.

- Achieved a 12% reduction in field operating costs, excluding transportation, since the second quarter 2012 and a 17% reduction when compared to the third quarter of 2011. Total field operating costs, including transportation, are $13.78/boe.

- Declared unitholder distributions of $0.26 per unit for the quarter ($0.0875 per unit per month).

- Drilled seven (5.7 net) oil wells during the quarter (nineteen (15.6 net) year to date). Six (4.8 net) horizontal wells were drilled in the Salt Flat Field (fifteen (12.0 net) year to date) and one (0.9 net) vertical well was drilled in the Permian Basin (four (3.7 net) year to date). In addition, one (0.8 net) salt water disposal well was drilled in the Salt Flat Field (two (1.6 net) year to date).

- Tied in ten (8.3 net) oil wells during the quarter (eighteen (14.9 net) year to date); eight (6.4 net) horizontal wells in the Salt Flat Field during the quarter (fourteen (11.2 net) year to date) and two (1.9 net) vertical wells during the quarter in the Permian Basin (four (3.7 net) year to date).

- Assumed operatorship of the recently acquired Permian Basin properties.

Results of operations

Production

Oil equivalent sales volumes (boe/d @ 6:1)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Oil (bbl/d)	2,477	995	2,289	1,159
Natural gas (mcf/d)	927	-	467	-
Natural gas liquids (bbl/d)	194	-	99	-
	2,825	**995**	**2,466**	**1,159**

Working interest sales volumes for the nine months ended September 30, 2012 averaged 2,466 boe/d (97% oil and natural gas liquids, 3% natural gas), 113% above September 30, 2011 levels. Third quarter 2012 volumes of 2,825 boe/d were 184% above the prior years' comparable quarter and 18% higher than the second quarter of 2012. The increase is attributable to the May 2012 Permian Basin acquisition, four additional tie-ins in the Permian and an additional 19 (15.2 net) horizontal oils brought on stream in the Salt Flat area since September 30, 2011.

Sales

$000's	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Oil	$ 19,844	$ 7,652	$ 56,955	$ 27,640
Natural gas	253	-	333	-
Natural gas liquids	645	-	969	-
Sales before royalties	**$ 20,742**	**$ 7,652**	**$ 58,257**	**$ 27,640**

Realized Prices				
Oil ($/bbl)	$ 87.09	$ 83.56	$ 90.80	$ 87.37
Natural gas ($/mcf)	2.97	-	2.61	-
Natural gas liquids ($/bbl)	36.17	-	35.86	-
Sales before royalties ($/boe)	79.80	83.56	86.23	87.37
Royalties ($/boe)	(21.40)	(23.14)	(23.76)	(24.23)
Revenue ($/boe)	**$ 58.41**	**$ 60.42**	**$ 62.47**	**$ 63.14**

Benchmark Prices				
Oil – WTI ($US/bbl)	$ 92.18	$ 89.40	$ 96.71	$ 98.09
Natural gas – Henry HUB ($US/mcf)	$ 2.80	-	$ 2.52	-

99% of Eagle's quarterly revenue is derived from oil and natural gas liquids. Realized natural gas liquids prices were approximately 40% of benchmark WTI for the quarter.

The third quarter 2012 benchmark $US WTI price increased 3% from the prior years' comparative quarter, with $US realized oil prices and Canadian dollar realized oil prices increasing by a commensurate amount.

The above prices do not include realized gains or losses from financial commodity contracts, which amounted to a gain of $26,000 ($0.10/boe) for the three months ended September 30, 2012 and a loss of $23,000 ($0.03/boe) for the nine months ended September 30, 2012 See *"Realized and unrealized risk management gain/loss".*

There is a quality differential between the benchmark West Texas Intermediate ("**WTI**") price and the $US price realized by Eagle. Eagle has negotiated a six month (September 2012 through February 2013) marketing agreement that pegs the reference price in the Salt Flat area to Louisiana Light Sweet instead of WTI at Cushing, Oklahoma. When combined with its existing marketing agreement, Eagle expects its September 2012 through February 2013 average oil price differential at Salt Flat to be a positive $US 1.53 per barrel. Eagle has also negotiated a 5 month (October 2012 through February 2013) marketing agreement for the Permian Basin. With this new marketing agreement in place, Eagle expects its October 2012 through February 2013 price differential for the Permian Basin to be a minus $US 1.91 per barrel relative to WTI. Management monitors pricing regularly and endeavors to maximize realized sales prices, while minimizing counterparty risk. A key part of the Trust's strategy is to acquire US properties which are close to markets and in so doing, realize attractive sales prices compared to Canadian production.

The overall royalty rate of 27% for the quarter is consistent with prior periods and the 28% year to date rate.

Cost of sales

	Three Months Ended September 30, 2012		Three Months Ended September 30, 2011		Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
	$	**/boe**	**$**	**/boe**	**$**	**/boe**	**$**	**/boe**
Transportation		2.35		2.01		2.09		1.96
Other field operating costs		11.42		13.84		12.80		9.81
	$	13.78	$	15.85	$	14.89	$	11.77
Depreciation, depletion and amortization		23.83		24.81		24.91		24.48
Cost of sales	**$**	**37.61**	**$**	**40.66**	**$**	**39.80**	**$**	**36.25**

Fuel, utilities and equipment rentals (generators) account for 40% of the 2012 year to date operating costs. Third quarter 2012 operating costs, excluding transportation, have been reduced by 12% when compared to the second quarter of 2012, and by 17% when compared to the third quarter of 2011. With the power installation now complete at Salt Flat, one or two generators are used temporarily until recently drilled well sites can be electrified. In addition, the electrical contract in the Salt Flat field has been renegotiated, resulting in approximate savings of $143,000 for the June to December 2012 period and a 37% drop in the per-kilowatt-hour rate for the December 2012 to December 2014 period.

The depletion, depreciation, and amortization provision for the period ended September 30, 2012 was based on proved plus probable reserves, including the future development costs associated with those reserves, as per the December 31, 2011 and March 31, 2012 reserves evaluation reports for Salt Flat and Permian Basin, respectively, as prepared by the Trust's independent reserves evaluators.

Field netback

	Three Months Ended September 30, 2012		Three Months Ended September 30, 2011		Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
$000's	**$**	**$/boe**	**$**	**$/boe**	**$**	**$/boe**	**$**	**$/boe**
Sales before royalties	20,742	79.80	7,652	83.56	58,257	86.23	27,640	87.37
Royalties	(5,561)	(21.40)	(2,119)	(23.14)	(16,052)	(23.76)	(7,667)	(24.23)
Transportation	(611)	(2.35)	(184)	(2.01)	(1,414)	(2.09)	(619)	(1.96)
Other operating costs	(2,970)	(11.42)	(1,267)	(13.83)	(8,646)	(12.80)	(3,103)	(9.81)
Field netback	**$ 11,600**	**$44.63**	**$ 4,082**	**$44.58**	**$ 32,145**	**$47.58**	**$ 16,251**	**$51.37**
Sales volumes (boe/d)		**2,825**		**995**		**2,466**		**1,159**

During the quarter, benchmark WTI averaged $US 92.18/bbl and Eagle realized a field netback of $44.63/boe.

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)	200 bbls/d	Nov 2011 to Oct 2012	$91.00
NYMEX (ii)	500 bbls/d	Jan 2012 to Dec 2012	$92.00-$105.00
NYMEX (ii)	300 bbls/d	May 2012 to Apr 2012	$95.00-$108.25
NYMEX (i)	200 bbls/d	Jan 2013 to Apr 2013	$103.45
NYMEX (i)	500 bbls/d	May 2013 to Dec 2013	$103.45
NYMEX (i)	400 bbls/d	Jan 2014 to Dec 2014	$98.00

Oil Fixed Price	Volume	Contract Term	Price $US
NYMEX (ii)	250 bbls/d	Aug 2012 to Jul 2013	$87.00-$89.70
NYMEX (ii)	250 bbls/d	Sep 2012 to Aug 2013	$90.00-$91.60
NYMEX (ii)	200 bbls/d	Nov 2012 to Dec 2012	$95.00-$103.75
NYMEX (ii)	300 bbls/d	Jan 2013 to Jul 2013	$95.00-$103.75
NYMEX (ii)	500 bbls/d	Aug 2013 to Aug 2013	$95.00-$103.75
NYMEX (ii)	800 bbls/d	Sep 2013 to Dec 2013	$95.00-$103.75
NYMEX (iii)	500 bbls/d	Jan 2014 to Dec 2014	$100.00

(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).

A strengthening forward commodity pricing environment since the second quarter has caused the future value of these contracts to decrease, thus reducing the unrealized asset position. Although the Trust currently has no intention of unwinding the contracts that are in place, it is required to calculate and record each quarter, using a mark-to-market valuation, the fair value of the remaining term of the contracts. As a result, a $3.9 million unrealized risk management loss was recorded for the quarter (three months ended September 30, 2011 - $1.2 million unrealized gain) and a $2.5 million unrealized gain for the nine months ended September 30, 2012 (nine months ended September 30, 2011 - $1.2 million unrealized gain).

Administrative expenses

Total administrative expenses for the third quarter were $1.3 million, 12% below third quarter 2011 levels on an absolute basis and 68% below third quarter 2011 levels on a per boe basis. On a go-forward basis, the Trust expects administrative expenses to be approximately $8.00/boe, which is a level similar to the September 30, 2012 year to date figure.

Unit-based compensation

Unit-based compensation expense of $2.3 million ($871,000 for the three months ended September 30, 2011) was recorded during the third quarter of 2012.

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 awards will depend on: (1) the price the escrowed units are eventually sold for by the holders of those units (which would not result in a cash outlay for the Trust), (2) the accumulated distributions actually paid by the Trust combined with the actual year over year price appreciation of the trust units with respect to holders of the restricted unit rights and unit rights, and (3) the actual price of the units relative to the exercise price of the options at the time the options are exercised (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 escrowed units, (2) the restricted unit rights, (3) the options and (4) the unit rights. Any changes in fair value are recorded as an expense.

From one quarter to the next, changes in the closing price of the units, accumulated distributions and changes to expected future unit price volatility serves to 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 September 30, 2011 to September 30, 2012 was due to: (1) a higher closing unit price on September 30, 2012 as compared to September 30, 2011 ($10.09 versus $9.72 per unit, respectively), (2) additional awards vesting over time and, (3) additional awards being granted during that period.

During the quarter, $959,000 was paid in cash representing two years of accumulated vested amounts for two thirds of the restricted unit rights that have vested. The liability that was, and is, being accrued from inception for these cash settled awards was reduced accordingly.

Tax horizon

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

Summary of quarterly results

	Q3/2012	Q2/2012	Q1/2012	Q4/2011	Q3/2011	Q2/2011	Q1/2011	YTD/2010[(1)]
($000's except for boe/d and per unit amounts)								
Sales volumes – boe/d	2,825	2,400	2,169	2,023	995	1,214	1,269	726
Revenue, net of royalties	15,181	13,077	13,947	11,798	5,533	7,305	7,135	1,366
per boe	58.41	59.90	70.67	63.40	60.42	66.10	62.49	60.72
Funds flow from operations	9,039	7,233	9,118	7,199	2,432	5,029	5,192	(288)
per boe	34.78	33.13	46.20	38.69	26.55	45.52	45.47	(12.81)
per unit – basic	0.32	0.31	0.50	0.39	0.14	0.28	0.29	(0.07)
Income (loss)	(1,095)	8,567	(952)	(1,426)	421	1,703	(1,911)	(3,212)
per unit – basic	(0.04)	0.37	(0.05)	(0.08)	0.02	0.10	(0.11)	(0.81)
Cash distributions declared	7,512	6,628	5,024	4,936	4,848	4,775	4,728	1,916
per issued unit	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.1064
Current assets	14,209	18,758	16,447	13,385	14,121	20,067	27,920	33,103
Current liabilities	23,723	28,158	20,319	16,557	12,023	7,299	11,712	9,062
Total assets	283,913	291,273	156,477	158,885	164,480	150,351	154,138	159,868
Total non-current liabilities	35,136	27,192	489	503	2,671	4,496	2,893	725
Unitholders' equity	225,055	235,923	135,669	141,826	149,785	138,556	139,532	150,081
Units outstanding for accounting purposes	28,654[(2)]	27,895[(2)]	18,847[(2)]	18,544[(2)]	18,174[(2)]	17,894[(2)]	17,624[(2)]	17,624[(1,2)]
Units issued	28,783	28,283	19,234	18,931	18,562	18,282	18,012	18,012

Note:

(1) 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.

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

With the exception of the third quarter of 2011, which had approximately 328 boe/d of oil temporarily shut in due to delays in obtaining Texas Commission on Environmental Quality permits, production has grown commensurate with well tie-ins. During the third quarter of 2012, ten (8.3 net) oil wells were tied in; eight (6.4 net) in the Salt Flat Field and two (1.9 net) in the Permian Basin.

Funds flow from operations increased in the third quarter of 2012, when compared to the prior quarter due to higher sales volumes. Second quarter 2012 funds flow from operations also included a one-time transaction cost of approximately $1.5 million associated with the acquisition of the Permian Basin properties. 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, as they did in the third quarter of 2011. 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 nor 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), which are required to be fair valued at each quarter end. As an example of this, even though third quarter 2012 funds flow from operations increased 25% from the prior quarter, income for the third quarter decreased significantly due to a strengthening commodity price environment (which affected the valuation of Eagle's commodity contracts) and a stronger unit price (which affected the fair market valuation of future unit based compensation).

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 a bank debt to cash flow ratio below 1.5 times.

The Trust believes that its expected funds flow from operations and the undrawn credit facility will be sufficient to fund its planned capital investment program, enable it to meet all current and expected financial requirements and maintain unitholder distributions. 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 is discretionary.

Funds flow from operations

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

	Three Months Ended September 30, 2012		Three Months Ended September 30, 2011		Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
$000's	$	$/boe	$	$/boe	$	$/boe	$	$/boe
Field netback	11,600	44.63	4,082	44.58	32,145	47.58	16,252	51.37
Cash settled award payments	(959)	(3.69)	-	-	(959)	(1.43)	-	-
Administrative expenses	(1,289)	(4.97)	(1,477)	(16.13)	(5,338)	(7.90)	(3,946)	(12.47)
Realized risk management gain (loss)	26	0.10	124	1.35	(23)	(0.03)	52	0.17
Finance expense	(407)	(1.56)	(19)	(0.21)	(652)	(0.96)	(45)	(0.14)
Realized foreign exchange gain(1)	68	0.27	(278)	(3.04)	217	0.32	340	1.07
Funds flow from operations	**$ 9,039**	**$ 34.78**	**$ 2,432**	**$ 26.55**	**$ 25,390**	**$37.58**	**$ 12,653**	**$ 40.00**

Notes:

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

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

Credit facility

As of September 30, 2012, the Trust had approximately $15.1 million of unused credit on its $US 48.5 million credit facility which is held indirectly through its U.S. subsidiary with a U.S. affiliate of a Canadian chartered bank.

Working capital

At September 30, 2012, the Trust had a working capital deficiency of $9.5 million (which becomes a $0.8 million working capital surplus when the fair market valuation of the non-cash liability for unit-based payments is excluded) and $33.4 million (September 30, 2011 - $ nil) drawn on its $US 48.5 million bank credit facility described above.

Unitholders' equity

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. Refer to the "Outlook" section for a discussion of the Trust's future plans.

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

As a result of its Premium Distribution™ and Distribution Reinvestment Plan, the Trust received proceeds resulting from the issuance of units from treasury to those unitholders who have opted to participate in the Plan. For the three months ended September 30, 2012, 500,604 units (nine months ended – 1,172,355 units) were issued for total proceeds of approximately $4.6 million (nine months ended - $11.5 million) at an average price of $9.30 per unit (nine months ended - $9.92 per unit).

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. Distributions paid in the third quarter (for the June, July and August 2012 record dates) totaled approximately $7.5 million.

At September 30, 2012, the Trust had issued 28,783,454 units. For purposes of the September 30, 2012 unaudited interim consolidated condensed financial statements, 28,654,287 units were shown as outstanding. The difference relates to 129,167 escrowed units previously issued on the surrender of performance options, which are excluded from financial statement figures because IFRS principles exclude units that require a performance condition be met before being released from escrow. Distributions are paid on the units while they are in escrow.

As at the date of this MD&A, 28,949,267 units are issued and 2,433,000 options are outstanding.

Capital expenditures

Capital spending during the period ended September 30, 2012 and September 30, 2011 was as follows:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine months Ended September 30, 2012	Nine Months Ended September 30, 2011
$000's	**$**	**$**	**$**	**$**
Exploration and evaluation(1)	99	265	183	587
Acquisition of the Salt Flat Field interest (adjustment)	-	(13)	-	(164)
Acquisition of Permian Basin properties	-	-	115,680	-
Intangible drilling and completions	12,634	8,014	20,403	17,853
Well equipment and facilities	3,252	3,255	11,819	5,966
Other	45	57	145	117
	$ 16,030	$ 11,578	$ 148,230	$ 24,359

Note:

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

On May 18, 2012, Eagle acquired 92.5% of the seller's 99% interest in certain Permian Basin properties and related assets, located near Midland, Texas for total cash consideration of $115.9 million, which includes closing adjustments of approximately $1.4 million. The acquisition had an effective date of April 1, 2012 and a closing date of May 18, 2012. Included in administrative expenses for the three and nine months ended September 30, 2012 is approximately $1.5 million of one-time transaction costs associated with this acquisition.

100% of the purchase price of the acquisition was paid in 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:		
Oil and Gas Properties	$	116,611
Decommissioning liabilities		(709)
	$	**115,902**

The acquisition agreement provides Eagle with the right and obligation to purchase all of the seller's remaining undivided 7.5% interest in the properties by no later than April 30, 2013 on similar terms and conditions as the acquisition, refer to the "Commitments" section note (5) of this MD&A.

During the third quarter, seven (5.7 net) oil wells were drilled with ten (8.3 net) wells tied in on Eagle's properties. Costs in the Permian Basin have recently begun to trend lower, which management attributes to the recent decline in the price of oil.

Power installation is now substantially complete at Salt Flat. The only generators still in use are one or two temporary generators that will continue to be used from time to time until recently drilled well sites are electrified.

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)(4)		389		202		187	-
Purchase obligation (5)(6)(7)		1,930		1,930		-	-
Total contractual obligations	**$**	**2,319**	**$**	**2,132**	**$**	**187**	**-**

Notes:

(1) Calgary, Alberta office lease: The initial term of the sublease agreement was for 6 months from January 1, 2011 until June 30, 2011. On July 25, 2011, the sublease agreement was renewed for an additional 6 month period from August 1, 2011 to January 31, 2012 under the same terms as before with the exception of a monthly rent rate of $8,500. Thereafter, the agreement will automatically roll over on a monthly basis, unless either party serves a 30 day notice of termination. Therefore, the agreement is cancellable at the end of the term if notice is provided. Future minimum lease payments during the additional six month term of the sublease were $51,000, with $nil remaining as at September 30, 2012.

(2) Houston, Texas office lease: The sublease agreement was entered into on April 1, 2011, and has an approximate 30 month term from April 7, 2011 through September 30, 2013. Future minimum lease payments during the term of the sublease approximate $US 338,400, with 12 months and approximately $US 135,000 remaining at September 30, 2012. In $CA the remaining future minimum lease payments approximate $133,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9832.

(3) Midland, Texas office lease: The agreement was entered into on July 31, 2012 and has an approximate 48 month term from October 15, 2012 through October 14, 2016. Future minimum lease payments during the term of the lease approximate $US 203,000. In $CA the future minimum lease payments approximate $199,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9832.

(4) Luling, Texas office lease: The sublease agreement was entered into on August 15, 2011, and has an approximate 12 month term from August 15, 2011 through August 31, 2012. On April 24, 2012, the lease agreement was extended for an additional 36 month period from September 1, 2012 to August 13, 2015 with a monthly rate of $US 1,650. Future minimum payments during the term of the sublease and the extension approximate $US 80,000, with $US 58,000 remaining at September 30, 2012. In $CA, the remaining future minimum lease payments approximate $57,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9832.

(5) The Permian Basin properties acquisition agreement dated May 18, 2012 provides Eagle with the right and obligation to purchase all of the seller's remaining undivided 7.5% interest in the properties by no later than April 30, 2013 on similar terms and conditions as the acquisition. The purchase price to be paid by Eagle for the remainder of the assets on the closing of such purchase will be determined by a formula based on the net present value of such assets as of January 1, 2013, as determined in an independent engineering report which is intended to approximate the fair market value at that time. The acquisition agreement restricts (other than ordinary course sales) the seller from, indirectly or directly, soliciting, negotiating or taking any other actions or steps in respect of a sale or possible sale of the remainder assets to any third party prior to April 30, 2013. Since the current fair value of this purchase obligation reflects the fair value at January 1, 2013 for the remaining interest, no amount has been recorded for this non-financial forward purchase contract.

(6) The Trust, through its operations in the Permian Basin, entered into a six well turnkey drilling rig commitment agreement effective July 23, 2012. At September 30, 2012, three wells have been drilled under the agreement. Future minimum payments are estimated to be approximately $US 3.4 million, which is 100% of the commitment. The net commitment to the Trust based upon its approximate 92.5% interest equates to $US 3.1 million with $US 1.7 million remaining at September 30, 2012. In $CA the net future commitment approximates $1.5 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 0.9832.

(7) The Trust, through its operations in the Salt Flat Field, amended its existing drilling rig commitment agreement to include an additional eight well drilling rig commitment effective July 27, 2012. At September 30, 2012, five of the additional eight wells have been drilled. Future minimum payments for the eight additional wells are estimated to be approximately $US 1.4 million, which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 1.1 million with $US 545,000 remaining at September 30, 2012. In $CA the remaining net future commitment approximates $430,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 0.9832.

Transactions with related parties

Key management personnel

Key management personnel consist of the Chief Executive Officer, Chief Operating Officer, Chief Financial Officer, 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.

Head office lease in Calgary, Alberta

The Trust subleases office space along with furniture and equipment from a company of which a director of the administrator of the Trust is the President and Chief Operating Officer. The terms of the agreement are recorded at the exchange amount. The monthly rent rate is $8,500, which approximates market value. Refer to "Commitments" section of this MD&A. No amounts were owing to this related party as at September 30, 2012. For the nine months ended September 30, 2012, administrative expenses included $76,500 (September 30, 2011 - $73,500) for amounts billed from this related party.

Critical accounting estimates

There have been no changes to the Trust's critical accounting estimates and judgments in the third quarter of 2012. Further information about the Trust's critical accounting estimates and judgments can be found in the notes to the Consolidated Financial Statements and MD&A for the year ended December 31, 2011.

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 joint venture partner, customer or counterparty to a financial instrument fails to meet its contractual obligations and 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 reasonable. 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. At September 30, 2012, the Trust had a working capital deficiency of $9.5 million (which becomes an $0.8 million working capital surplus when the fair market valuation of the non-cash liability for unit-based payments is excluded). In addition, the Trust had $33.4 million drawn on its $US 48.5 million bank credit facility. 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. To better manage its liquidity risk, the Trust prepares an annual capital expenditure budget, which is 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 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 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 may enter into certain financial derivative instruments periodically to economically hedge some oil 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 net production. 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.

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 of September 30, 2012, $33.4 million was drawn against the credit facility (September 30, 2011 – nil). The Trust did not hedge against any interest rate exposures.

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 2012 and 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 discussion under "Note about forward-looking statements".

- 2012 full year average production guidance reduced from 2,900 boe/d, to approximately 2,700 boe/d.
- Fourth quarter 2012 average production expected to be approximately 11% above third quarter levels.
- Second half 2012 average production guidance reduced from 3,600 boe/d to approximately 3,000 boe/d.
- 2012 exit rate production guidance of approximately 3,300 boe/d, with approximately 1,000 boe/d (95% oil and NGL) coming from the Midland area and 2,300 boe/d (100% oil) coming from the Luling area.
- 2012 full year average operating cost guidance maintained at approximately $15.00 per boe, trending below $13.00 per boe during the fourth quarter.
- 2012 full year funds flow from operations guidance reduced from $46.4 million[1] to approximately $37.0 million[2].
- Full year 2012 capital expenditures of approximately $43.0 million, consistent with existing guidance of $42.0 million.
- Exit 2012 with an approximate 1.0 x debt to trailing cash flow ratio.
- Distributions remain sustainable.
- 2012 payout ratio[3] expected to increase from 60% to approximately 70%.

In the Midland area (Permian Basin), Eagle remains focused on growing this multi-zone stacked pay resource to 1,000 boe/d (up from approximately 600 boe/d at the time of acquisition) by the end of 2012. To date, five wells have been tied in and brought on stream in the Midland area since the April 1, 2012 effective date of the acquisition. These new wells are performing as expected.

In the Luling area (Salt Flat Field), although some wells performed above type curve forecast, in aggregate the 2012 program did not meet expectations. Eagle has reviewed its drilling practices and has determined that failure to displace drilling mud and cuttings curtailed production from these wells. The drilling mud program has been changed and a wellbore clean out program is underway. Although the 2012 drilling program was over budget, the last five wells in the program achieved the best cost performance to date, all coming in below budget. Four of these five wells have been brought on production and, in aggregate, are producing at expected type curve levels. Notwithstanding these challenges, Eagle’s 2012 expected exit rate for this field will still result in a greater than seven fold production increase since it was acquired effective June 1, 2010.

Eagle does not anticipate any negative revisions to reserves as the adjustment to Eagle's guidance is due to drilling delays and potential mud displacement issues during completion techniques only.

Notes:

(1) Assumed $US 88 WTI, natural gas $US 2.68 NYMEX and 2012 average working interest production of 2,900 boe/d.

(2) Assuming $US 88 WTI, natural gas $US 2.90 NYMEX and 2012 average working interest production of 2,700 boe/d.

(3) Eagle calculates this ratio as follows: Unitholders Distributions / Funds flow from operations.

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.

	Full year impact on ➔	**Funds flow from operations ($000's)**	**Funds flow from operations / unit ($)(1)**
Gas price(2)	+ USD $0.10/mcf Henry HUB	0	0.00
Oil price (2)	+ USD $1.00/bbl WTI	630	0.02
Gas production	+1000 mcf/d	0	0.00
Oil production	+100 bbls/d	1,800	0.07
Currency (2)	+CDN strengthen by $0.01	(425)	(0.02)
Interest Rate	+1% prime	170	0.01

Notes:

(1) Per unit figures are based on 28,155,557 weighted average basic units outstanding for the quarter ended September 30, 2012.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate equal to year to date average sales volumes of 2,466 bbls per day.

Non-IFRS financial measures

The following table reconciles the non-IFRS financial measures "funds flow from operations" and "field netback" to "loss for the period", the most directly comparable measure in the Trust's consolidated financial statements:

$000's	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	NIne Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Income (Loss)	**$ (1,095)**	**$ 421**	**$ 6,521**	**$ 213**
Add back (deduct) items not involving cash:				
Depreciation depletion and amortization	6,221	2,284	16,906	7,772
Income tax recovery - deferred	(1,415)	-	-	-
Unit based compensation – non-cash portion	1,373	871	4,371	5,776
Unrealized risk management loss (gain)	3,853	(1,171)	(2,468)	(1,177)
Finance expense	102	27	60	69
Funds flow from operations	**$ 9,039**	**$ 2,432**	**$ 25,390**	**$ 12,653**
Add back (deduct) items not directly related to field operations:				
Realized foreign exchange gain	(68)	278	(217)	(340)
Finance expense (cash portion)	407	19	652	45
Risk management (gain) loss-realized	(26)	(124)	23	(52)
Administrative expenses	1,289	1,477	5,338	3,946
Cash settled award payments	959	-	959	-
Field netback	**$ 11,600**	**$ 4,082**	**$ 32,145**	**$ 16,252**

No change in internal controls over financial reporting during the period July 1, 2012 to September 30, 2012

During the period beginning on July 1, 2012 and ended on September 30, 2012, 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.

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

- the Trust's expectation regarding its average working interest production for the fourth quarter, second half and full year of 2012;
- the 2012 exit rate production for the Midland area, Luling area and in total;
- Eagle's expectation regarding its 2012 operating costs;
- Eagle's expectation regarding its 2012 funds flow from operations;
- Eagle's 2012 capital expenditures;
- the Trust's expectations regarding its debt to trailing cash flow ratio at the end of 2012;
- amount and sustainability of distributions; and
- commodity prices and exchange rates.

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

- future oil and natural gas prices;
- future currency exchange and interest 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;"
- estimates of anticipated production from both the Salt Flat Field assets and the Permian Basin assets, which estimates are 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 for both the Salt Flat Field assets and the Permian Basin assets, which are based on historical information and anticipated increases in the cost of equipment and services
- future recoverability of reserves for both the Salt Flat Field assets and the Permian Basin assets;
- 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 2012 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; and
- the ability of the Trust to compete for new acquisitions.

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 AIF:

- volatility of commodity prices;
- commodity supply and demand;
- fluctuations in currency and interest rates;
- inherent risks and changes in costs associated in the drilling and development of petroleum properties;
- unexpected operational delays and challenges;
- access to drilling equipment on a timely basis and at reasonable prices;
- ultimate recoverability of reserves;
- timing, results and costs of drilling activities and resulting production;
- availability of financing and capital; and
- new regulations and legislation that apply to the Trust and the operations of its subsidiaries.

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

The success of Eagle's drilling program is a key assumption in the production estimates for the 2012 financial year. The primary risk factors which could lead to Eagle not meeting its production targets are: (i) production additions from drilling activity are less than expected; (ii) a lack of access to drilling rigs and related equipment on a timely basis and at reasonable prices due to high industry demand or poor weather; and (iii) unexpected operational delays and challenges. Increases in capital costs from forecast amounts can result from the foregoing reasons as well as general cost inflation in the industry. Additionally, Eagle may choose to decrease capital expenditures from those anticipated in its budget projections, therefore affecting production estimates for the 2012 financial year. There are many factors that could result in production levels being less than anticipated, including greater than anticipated declines in existing production due to poor reservoir performance, the unanticipated encroachment of water or other fluids into the producing formation, mechanical failures or human error or inability to access production facilities, among other factors.

As a result of these risks, actual performance and financial results in 2012 may differ materially from any projections of future performance or results expressed or implied by these forward-looking statements. 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.