EAGLE ENERGY™ TRUST

Management's Discussion and Analysis

August 9, 2012

This Management's Discussion and Analysis ("**MD&A**") of financial condition and results of operations for Eagle Energy Trust (the "**Trust**"), dated August 9, 2012, should be read in conjunction with the unaudited interim condensed consolidated financial statements and accompanying notes for the period ended June 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 International Financial Reporting Standards ("**IFRS**"). Items included in the financial statements of each of the Trust's subsidiaries are measured using the currency of the primary economic environment in which the entity operates (the "**functional currency**"). The Interim Financial Statements are presented in Canadian dollars, which is the functional and presentation currency of the Trust.

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

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

Non-IFRS financial measures

Statements throughout this MD&A make reference to the terms "field netback" and "funds flow from operations" which are non-IFRS financial measures that do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that "field netback" and "funds flow from operations" provide useful information to investors and management since such measures reflect the quality of production, the level of profitability, the ability to drive growth through the funding of future capital expenditures and the sustainability of distributions to unitholders. Funds flow from operations is calculated before changes in non-cash working capital. 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 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. Concurrent with closing this financing, the Trust's wholly-owned subsidiary acquired 92.5% of the seller's interest in certain Permian Basin properties, located near Midland, Texas.

Throughout this MD&A, Eagle Energy Trust and its subsidiaries are collectively referred to as "the Trust" for purposes of convenience. In addition, references to the results of operations refer to operations of the Trust's U.S. subsidiary, Eagle Energy Acquisitions LP ("**Eagle**").

Highlights for the three month period ended June 30, 2012

- Acquired 92.5% working interest in certain Permian Basin properties, located near Midland, Texas for total cash consideration, including closing adjustments, of $115,680,000. Working interest production from the acquired assets was approximately 600 barrels of oil equivalent ("boe") per day ("boe/d") comprised of 88% oil and natural gas liquids and 12% natural gas.

- Closed a bought deal financing of 7,730,000 trust units at a price of $11.00 per trust unit for proceeds of $85,030,000. In addition, the underwriters were granted an over-allotment option, and purchased an additional 950,000 trust units for additional proceeds of $10,450,000.

- Negotiated an expanded $US 48.5 million credit facility (from $US 31 million), with $US 24.8 million of credit available at June 30, 2012.

- Drilled eight (6.5 net) oil wells during the quarter (ten (8.1 net) year to date). Seven (5.6 net) horizontal wells were drilled in the Salt Flat Field (nine (7.2 net) year to date) and one (0.9 net) vertical well was drilled in the Permian Basin. In addition, one (0.8 net) salt water disposal well was drilled in the Salt Flat Field.

- Tied in seven (5.6 net) oil wells during the quarter (eight (6.4 net) year to date); five (3.7 net) horizontal wells in the Salt Flat Field during the quarter (six (4.5 net) year to date) and two (1.9 net) vertical wells during the quarter in the Permian Basin.

- Achieved average working interest sales volumes of 2,400 boe/d.

- Recorded funds flow from operations of $7.2 million ($33.13 per boe or $0.31 per unit), up approximately 44% from $5 million in the second quarter of 2011 ($45.51 per boe or $0.28 per unit).

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

- Negotiated a new six month (September 2012 through February 2013) marketing arrangement that, when combined with its existing marketing agreement, will create an average $5.20 per barrel positive swing in the oil price differential at Salt Flat for the July through December 2012 period.

Results of operations

Revenue

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Sales volumes – boe/d	**2,400**	**1,214**	**2,284**	**1,241**

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	$ /boe	**$ /boe**	**$ /boe**	**$ boe**
Benchmark WTI ($US)	93.51	102.56	98.18	98.27
Realized sales price ($US)	87.90	96.04	92.69	91.67
Differential to benchmark ($US)	$ 5.61	$ 6.52	$ 5.48	$ 6.60
Oil sales before royalties	84.00	91.61	90.25	88.96
Royalties	(24.11)	(25.51)	(25.24)	(24.69)
Revenue	**$ 59.90**	**$ 66.10**	**65.01**	**$ 64.27**

Working interest sales volumes for the six months ended June 30, 2012 averaged 2,284 boe/d (98% oil and natural gas liquids), an 84% increase from June 30, 2011 levels. Second quarter 2012 volumes benefitted from 30 (23.9 net) horizontal oils wells being tied in and brought on stream since the second quarter of 2011, as well as production from the Permian Basin properties from the acquisition closing date of May 18, 2012.

The benchmark WTI price decreased 8.8% from second quarter 2011, with $US realized prices and Canadian dollar realized prices decreasing by a commensurate amount. Not included in this figure is a realized gain on commodity contracts of $207,341 ($0.95 per boe) for the three months ended June 30, 2012 and a realized loss of $48,642 ($0.12 per boe) for the six months ended June 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 sales price realized by Eagle. Eagle recently 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 Cushing, Oklahoma. When combined with its existing marketing agreement, Eagle expects its July through December 2012 average oil price differential at Salt Flat to go from its present negative differential to a positive $US 0.20 per barrel differential and its January 2013 to February 2013 price differential to be a positive $US 1.66 per barrel. The Trust continues to monitor these differentials to ensure that volumes will be marketed at differentials to the WTI posted price that are deemed by management to be optimal.

The overall royalty rate of approximately 29% was slightly above previous quarters due to the recently acquired Permian Basin properties.

Cost of sales

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	$ /boe	**$ /boe**	**$ /boe**	**$ /boe**
Transportation	1.89	1.90	1.93	1.94
Other operating costs	13.04	6.78	13.65	8.17
	$ 14.93	$ 8.68	15.59	10.11
Depreciation, depletion and amortization	25.46	23.39	25.59	24.36
Cost of sales	**$ 40.39**	**$ 32.07**	**$ 41.18**	**34.47**

Fuel and power, utilities and equipment rentals (generators) account for 43% of operating costs during the second quarter of 2012 versus 19% for the three months ended June 30, 2011. Second quarter 2012 operating costs include $5.68 (June 30, 2011 - $1.67) per boe relating to diesel generators that were used to produce a large number of wells. With power installation now complete at Salt Flat, the only generators still in use are temporary generators that will continue to be used from time to time until recently drilled well sites are electrified. In addition, Eagle recently negotiated a revision to its current electrical contract that will result in a 37% lower per-kilowatt-hour rate than what is currently being charged for the remainder of 2012 and a new contract for two years beyond.

The depletion, depreciation, and amortization provision for the period ended June 30, 2012 was based on proved plus probable reserves, including the future development costs associated with those reserves, as found in 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 June 30, 2012		Three Months Ended June 30, 2011		Six Months Ended June 30, 2012		Six Months Ended June 30, 2011	
($000's)	**$**	**$/boe**	**$**	**$/boe**	**$**	**$/boe**	**$**	**$/boe**
Oil sales before royalties	18,340	84.00	10,123	91.61	37,515	90.25	19,988	88.96
Royalties	(5,263)	(24.11)	(2,818)	(25.51)	(10,490)	(25.24)	(5,548)	(24.69)
Transportation	(413)	(1.89)	(210)	(1.90)	(803)	(1.93)	(435)	(1.94)
Other operating costs	(2,848)	(13.04)	(750)	(6.78)	(5,676)	(13.65)	(1,836)	(8.17)
Field netback	**$9,816**	**$44.96**	**$6,345**	**$57.42**	**$ 20,545**	**$49.43**	**$12,169**	**$54.16**
Sales volumes (boe/d)		**2,400**		**1,214**		**2,284**		**1,241**

During the quarter, benchmark WTI averaged $US 93.51 per barrel of oil and the Trust realized a field netback of $44.96 per 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: (i) a fixed contract to sell 200 barrels of oil per day with a November 2011 through October 2012 term at a price of $US 91.00 per barrel; (ii) a costless collar for 500 barrels 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; (iii) a costless collar for 300 barrels 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; (iv) a fixed contract to sell 200 barrels of oil per day with a January 2013 through April 2013 term and 500 barrels of oil per day with a May 2013 through December 2013 term, at a price of $US 103.45 per barrel; (v) a fixed contract to sell 400 barrels of oil per day with a January 2014 through December 2014 term, at a price of $US 98.00 per barrel; (vi) 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; and (vii) a costless collar contract or 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.

A weaker forward commodity pricing environment relative to the previous valuation date at the end of the first quarter caused the future value of these contracts to swing from an unrealized liability position to an 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, using a mark-to-market valuation, the fair value of the remaining term of the contracts at the end of each reporting period. As a result, a $7,250,874 unrealized risk management gain was recorded for the quarter (six months ended June 30, 2012 - $6,320,829 gain). For the quarter, the Trust also realized a $207,341 risk management gain (six months ended June 30, 2012 – $48,642 loss) relating to these contracts in its income statement resulting in a net risk management gain of $7,458,214 for the quarter (six months ended June 30, 2012 - $6,272,186 gain).

Administrative expenses

Total administrative expenses for the second quarter were $2,736,447, $1,379,681, or 102%, above second quarter 2011 levels. On a per boe basis, general and administrative expenses were 2% higher than second quarter 2011 levels. The second quarter 2012 figure includes approximately $1.5 million of one-time transaction costs associated with the acquisition of the Permian Basin properties. On a go-forward basis, per boe administration costs are expected to trend lower due to increased production.

Unit-based compensation

A non-cash unit-based compensation expense recovery of $1,006,796 ($2,130,454 expense for the three months ended June 30, 2011) was recorded during the second quarter, reducing the existing liability. The components of the expense recovery related to (i) $527,016 for the estimated fair value of escrowed units and restricted unit rights that were previously issued upon surrender of performance options ($1,153,598 for June 30, 2011); (ii) $390,026 for the estimated fair value of options granted under the option plan ($960,739 for June 30, 2011); and (iii) $89,754 for the estimated fair value of phantom unit rights granted under the phantom unit rights plan ($16,117 for June 30, 2011).

The dollar amount of unit-based compensation expense does not represent cash paid by the Trust. The Trust is, however, required to re-determine the fair value of the liability relating to the escrowed units, restricted unit rights, options and phantom unit rights at the end of each reporting period and record any changes in fair value through the income statement. The actual value realized by holders of the awards will depend on the price the escrowed units are eventually sold for, the accumulated distributions actually paid by the Trust, the actual year over year price appreciation of the units, the actual price of the units, the actual exercise price of the options at the time the options are exercised and the actual payments pursuant to the phantom unit rights plan.

From one reporting period to the next, changes in the closing price of the units, accumulated distributions and expected future unit price volatility will increase or decrease the fair values that are derived using the Black-Scholes valuation model and cause corresponding swings in the amount recorded in the income statement. The decrease in the liability and associated expense recovery from June 30, 2011 to June 30, 2012 was primarily due to the June 30, 2012 unit price being less than the June 30, 2011 unit price ($9.76 versus $11.30 per unit, respectively).

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 the Trust executes its business plan. No taxes are expected to be payable by the Trust in Canada because the Trust will distribute its full taxable income each year to unitholders and will not be a SIFT trust, as defined under the *Income Tax Act* (Canada), provided that the Trust complies at all times with the investment restrictions as set forth in the Trust Indenture.

Summary of quarterly results

	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 (98% light oil)	2,400	2,169	2,023	995	1,214	1,269	726
Revenue, net of royalties	13,077	13,947	11,798	5,533	7,305	7,135	1,366
per boe	59.90	70.67	63.40	60.42	66.10	62.49	60.72
Funds flow from operations	7,233	9,118	7,199	2,432	5,029	5,192	(288)
per boe	33.13	46.20	38.69	26.55	45.52	45.47	(12.81)
per unit – basic	0.31	0.50	0.39	0.14	0.28	0.29	(0.07)
Income (loss)	8,567	(952)	(1,426)	421	1,703	(1,911)	(3,212)
per unit – basic	0.37	(0.05)	(0.08)	0.02	0.10	(0.11)	(0.81)
Cash distributions declared	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	0.1064
Current assets	18,758	16,447	13,385	14,121	20,067	27,920	33,103
Current liabilities	28,158	20,319	16,557	12,023	7,299	11,712	9,062
Total assets	291,273	156,477	158,885	164,480	150,351	154,138	159,868
Total non-current liabilities	27,192	489	503	2,671	4,496	2,893	725
Unitholders' equity	235,923	135,669	141,826	149,786	138,556	139,532	150,081
Units outstanding for accounting purposes	27,895[2]	18,847[2]	18,544[2]	18,175[2]	17,894[2]	17,624[2]	17,624[1,2]
Units issued	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 387,500 units issued 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 second quarter of 2012, seven (5.6 net) oil wells were tied in, five (3.7 net) in the Salt Flat Field and two (1.9 net) in the Permian Basin.

Funds flow from operations is lower in the second quarter of 2012, when compared to the prior quarter because the positive volume variance has been more than offset by the negative quarter over quarter price variance. Second quarter funds flow from operations also includes approximately $1.5 million of one-time transaction costs 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, such as unit-based compensation or the mark-to-market value of existing commodity pricing contracts. During the second quarter of 2012, the weakening commodity pricing environment caused a large unrealized gain on risk management contracts, compared to a loss for the first quarter of 2012.

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.

On May 18, 2012, the Trust closed a bought deal financing of 7,730,000 trust units at a price of $11.00 per trust unit for proceeds of $85,030,000. In addition, the underwriters were granted an over-allotment option, and, on May 31, 2012, purchased an additional 950,000 trust units for additional proceeds of $10,450,000.

The proceeds of the bought deal financing were used to partially fund the purchase price of 92.5% working interest in certain Permian Basin assets, located near Midland, Texas for total cash consideration, including closing adjustments, of $115,680,000. Working interest production from the acquired assets was approximately 600 boe/d comprised of 88% oil and natural gas liquids and 12% natural gas.

In addition, the Trust's lender approved an increase in the borrowing base of its credit facility to $US 48.5 million from $US 31 million to fund the remaining balance of the acquisition. At June 30, 2012, $24,128,970 was drawn under the credit facility.

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 June 30, 2012		Three Months Ended June 30, 2011		Six Months Ended June 30, 2012		Six Months Ended June 30, 2011	
($000's)	**$**	**$/boe**	**$**	**$/boe**	**$**	**$/boe**	**$**	**$/boe**
Field netback	9,816	44.96	6,345	57.42	20,545	49.43	12,169	54.16
Administrative expenses (1)	(2,711)	(12.42)	(1,357)	(12.28)	(4,048)	(9.74)	(2,484)	(11.05)
Realized risk management gain (loss)	207	0.95	(53)	(0.48)	(49)	(0.12)	(72)	(0.32)
Finance expense	(219)	(1.00)	(6)	(0.05)	(246)	(0.59)	(11)	(0.05)
Realized foreign exchange gain(2)	139	0.64	100	0.91	149	0.36	619	2.75
Funds flow from operations	**$** 7,232	**$**33.13	**$**5,029	**$**45.52	$16,351	$39.34	**$10,221**	**45.49**

Notes:

(1) On a go-forward basis, per boe administrative costs are expected to trend lower due to increased production.

(2) 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 June 30, 2012, the Trust had $24,371,030 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 June 30, 2012, the Trust had a working capital deficiency of $9.4 million (which becomes a $2.1 million surplus when the non-cash current portion of unit-based compensation is excluded) and $24,128,970 (June 30, 2011 - $ nil) drawn on its $US 48.5 million bank credit facility described above.

Unitholders' equity

On May 18, 2012, the Trust closed a bought deal financing of 7,730,000 trust units at a price of $11.00 per trust unit for proceeds of $85,030,000. In addition, the underwriters were granted an over-allotment option, and, on May 31, 2012, purchased an additional 950,000 trust units for additional proceeds of $10,450,000. Total proceeds of the offering, including the proceeds from the exercise of the over-allotment option, was $95,480,000. Refer to the "Outlook" section for a discussion of the Trust's future plans.

All other issuances of Trust capital 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 June 30, 2012, 368,374 units (six months ended - 671,751 units) were issued for total proceeds of approximately $3.8 million (six months ended - $6.8 million) at an average price of $10.23 per unit (six months ended - $10.16 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 second quarter (for the March, April and May 2012 record dates) totaled approximately $5.8 million.

At June 30, 2012, the Trust had issued 28,282,850 units. For purposes of the June 30, 2012 unaudited interim consolidated condensed financial statements, 27,895,360 units were shown as outstanding. The 387,500 difference relates to units previously issued on the surrender of performance options that 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, 28,433,772 units are issued and 1,706,000 options are outstanding.

Capital expenditures

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

	Three Months Ended June 30, 2012	**Three Months Ended June 30, 2011**	**Six Months Ended June 30, 2012**	**Six Months Ended June 30, 2011**
($000's)	**$**	**$**	**$**	**$**
Exploration and evaluation(1)	1	172	85	322
Acquisition of the Salt Flat Field interest (adjustment)	-	(32)	-	(151)
Acquisition of Permian Basin properties	115,680	-	115,680	-
Intangible drilling and completions	8,049	5,019	7,769	9,839
Well equipment and facilities	5,812	2,077	8,566	2,710
Other	18	32	99	60
	$ 129,560	$ 7,268	$ 132,199	$ 12,780

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, located near Midland, Texas for total cash consideration of $115,680,000, which includes closing adjustments of $1,165,734. 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 six months ended June 30, 2012 is approximately $1.5 million of one-time transaction costs associated with the acquisition of the Permian Basin properties.

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

Identifiable assets acquired and liabilities assumed:

Oil and Gas Properties	$	116,389
Decommissioning liabilities		(709)
	$	**115,680**

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 second quarter, eight (6.5 net) oil wells were drilled with seven (5.6 net) tied in. While costs on some wells have come in under budget, Eagle has experienced cost overruns due to drilling rig start up and wellbore problems on the last two wells at Salt Flat. Costs in the Permian Basin appear to have come down slightly due to the recent decline in the price of oil.

Related infrastructure investment and construction of a power trunk line in the Salt Flat Field continued throughout the second quarter with the objective to remove all generators currently in use as soon as possible to reduce operating costs. With power installation now complete at Salt Flat, the only generators still in use are 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)	236	158	78	-
Purchase obligation (4)(6)(7)	4,605	4,605	-	-
Total contractual obligations	**$ 4,841**	**$ 4,763**	**$ 78**	**-**

Notes:

(1) Calgary, Alberta office lease: The initial term of the sub-lease agreement was for 6 months from January 1, 2011 until June 30, 2011. On July 25, 2011, the sub-lease 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 six month term of the sub-lease were $51,000, with $nil remaining as at June 30, 2012.

(2) Houston, Texas office lease: The sub-lease 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 sub-lease approximate $US 338,400, with 15 months and approximately $US 169,000 remaining at June 30, 2012. In $CA the remaining future minimum lease payments approximate $172,300 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.0181.

(3) Luling, Texas office lease: The sub-lease 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 sub-lease and the extension approximate $US 80,000, with $US 62,700 remaining at June 30, 2012. In $CA, the remaining future minimum lease payments approximate $63,800 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA1.0181.

(4) The Trust, through its operations in the Salt Flat Field, entered into a nine well drilling rig commitment agreement effective December 15, 2011. At June 30, 2012, seven wells had been drilled under the agreement. Future minimum payments are estimated to be approximately $US 1,100,000, which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 880,000 with $US 202,000 remaining at June 30, 2012. In $CA the net future commitment approximates $205,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.0181.

(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 drilling rig commitment agreement effective July 23, 2012. 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. In $CA the net future commitment approximates $3.2 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.0181.

(7) The Trust, through its operations in the Salt Flat Field, amended its current nine well drilling rig commitment agreement to include an additional eight well drilling rig commitment effective July 27, 2012. Future minimum payments of 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. In $CA the remaining net future commitment approximates $1.2 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.0181.

Transactions with related parties

Key management personnel

Key management personnel consist of the Chief Executive Officer (CEO), Chief Operating Officer (COO), Chief Financial Officer (CFO), 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 sub-leases 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 June 30, 2012. For the six months ended June 30, 2012 administrative expenses included $51,000 (June 30, 2011 - $48,000) 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 second 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 reasonably feasible. Joint venture receivables are with customers in the oil and gas industry and are subject to normal industry credit risks. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. In certain circumstances, the Trust may request an operating advance or cash call a partner in advance of expenditures being incurred.

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. At June 30, 2012, the Trust had a working capital deficiency of $7.3 million (which becomes an $4.2 million surplus when the non-cash current portion of unit-based compensation is excluded) and $24,128,970 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 in the coming 12 months. 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 June 30, 2012, $24,128,970 was drawn against the credit facility and no amounts were outstanding under the credit facility as of June 30, 2011. 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".

Eagle expects its average working interest production for the full year 2012 to be approximately 2,900 boe/d. Eagle maintains its previous guidance of average working interest production for the second half of 2012 to be approximately 3,600 boe/d.

Eagle also maintains its previous guidance of 2012 full year average operating costs of approximately $15.00 per boe, which includes an increase in Salt Flat operating costs of approximately $4.00 per boe due to the use of diesel generators in the first half of 2012 to bring production on stream.

Eagle has revised its 2012 full year capital budget to $US 42 million (previously $US 32 million), consisting of:

- $US 24.5 million for Salt Flat (a $US 4.5 million increase), which includes 16 (12.8 net) horizontal oil wells, 3 (2.1 net) sidetrack re-entry wells, 2 (1.6 net) salt water disposal wells, 2.5 (2 net) batteries, completion of the electrification of the Salt Flat Field, and increased capital in 5 wells due to increased costs.

- $US 17.5 million (a $US 5.5 million increase) to drill 8 (7.4 net) wells and tie-in 7 (6.5 net) wells on the Permian Basin properties.

Eagle expects its 2012 full year funds flow from operations to be approximately $46.4 million (assuming $US 88 WTI, natural gas $US 2.68 NYMEX and 2012 average working interest production of 2,900 boe/d).

Sustainability of Distributions

Eagle's strategy is to target a sustainability ratio below 100%. Eagle calculates this ratio as follows:

$$\frac{\text{Capital Expenditures + Unitholder Distributions}}{\text{Funds flow from Operations}} = \text{Sustainability Ratio}$$

Eagle's 2012 sustainability ratio is expected to be approximately 150% due to the recent acquisition of the Permian Basin properties and the accelerated near term capital for those properties. This program is expected to more than double current production over the next 18 months and will allow Eagle to move toward its target.

A table showing the sensitivity of Eagle's sustainability ratio to production and pricing is set out below.

Payout Ratio

Eagle's strategy is to target a 50% payout ratio. Eagle calculates this ratio as follows:

$$\frac{\text{Unitholder Distributions}}{\text{Funds flow from Operations}} = \text{Payout Ratio}$$

Eagle's 2012 payout ratio is expected to be approximately 60% due to the recent acquisition of the Permian Basin properties and accelerated near term capital for those properties. A table showing the sensitivity of Eagle's payout ratio to production and pricing is set out below.

Sensitivities of Cash flow, Payout Ratio and Sustainability Ratio

The following tables describe the sensitivity of Eagle's cash flow, payout ratio and sustainability ratio to production levels and commodity prices.

Sensitivity of Cashflow ($ millions) to Production and Commodity Price

		2012 (Jul. – Dec.) Average WTI		
		$78.00	**$88.00**	**$98.00**
2012 Average WI Production (boe/d)	**2,700**	$41.4	$42.8	$44.9
	2,900	$44.7	$46.4	$48.8
	3,100	$48.0	$50.0	$52.7

Sensitivity of Payout Ratio to Production and Commodity Price

		2012 (Jul. – Dec.) Average WTI		
		$78.00	**$88.00**	**$98.00**
2012 Average WI Production (boe/d)	**2,700**	63%	61%	58%
	2,900	58%	56%	53%
	3,100	54%	52%	49%

Sensitivity of Sustainability Ratio to Production and Commodity Price

		2012 (Jul. – Dec.) Average WTI		
		$78.00	**$88.00**	**$98.00**
2012 Average WI Production (boe/d)	**2,700**	164%	159%	151%
	2,900	152%	146%	139%
	3,100	141%	136%	129%

Assumptions:
1. Annual distributions are held at current levels of $1.05 per unit per year.
2. No new equity issued, other than distribution reinvestment program.
3. Field operating costs, including transportation, of approximately $15.00 per boe.
4. Capital budget of $US 42 million.
5. Differential to WTI held constant at WTI plus $US 0.20 per barrel of oil for Salt Flat (July to December, 2012), not including transportation.
6. Foreign exchange rate: $1.00 CDN = $1.00 USD.
7. Effects of hedging have been considered.

Sensitivity of Distributions to Foreign Exchange

Management is assuming foreign exchange to be at par for 2012. The impact of fluctuations in the US dollar versus Canadian dollar foreign exchange rates on Trust distributions is reduced since substantially all of Eagle's funds flow from operations is in US dollars. Also, a targeted 50% payout ratio further reduces the impact of foreign exchange on distributions. Based on a 2012 pricing assumption of $US 88 WTI per barrel of oil, average production of 2,900 boe/d and other assumptions as listed above, a weakening of the Canadian dollar by $0.02 relative to the US dollar results in a decrease in the payout ratio from 56% to 55% and a decrease in the sustainability ratio from 146% to 145%.

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 as well as movements in foreign-exchange rates. Changes in production also affect funds flow. Sensitivities to these factors are summarized below: (note that sensitivities to changes in natural gas prices, natural gas production and interest rates have not been provided since the Trust did not have any significant natural gas production to the end of the second quarter of 2012 and incurred debt just prior to the end of the second quarter).

	Full year impact on ➔	**Funds flow from operations ($000's)**	**Funds flow from operations / unit [1]**
Gas price	+ USD $0.10/mcf Henry HUB	N/A	N/A
Oil price [2]	+ USD $1.00/bbl WTI	604	$ 0.03
Gas production	+1000 mcf/d	N/A	N/A
Oil production	+100 bbls/d	1,804	$ 0.08
Currency [2]	+CDN strengthen by $0.01	(410)	$(0.02)
Interest Rate	+1% prime	N/A	N/A

Notes:

(1) Per unit figures are based on 22,994,870 weighted average basic units outstanding for the quarter ended June 30, 2012.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate equal to year to date average sales volumes of 2,284 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:

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Income (Loss)	**$ 8,567**	**$ 1,703**	**$ 7,615**	**$ (208)**
Add back (deduct) items not involving cash:				
Unit-based compensation	(1,007)	2,130	2,998	4,905
Unrealized risk management gain	(7,251)	(1,419)	(6,321)	(6)
Depletion, amortization and accretion	5,584	2,593	10,685	5,488
Deferred income tax	1,415	-	1,415	-
Finance expense	(75)	22	(41)	42
Funds flow from operations	**$ 7,233**	**$ 5,029**	**$ 16,351**	**$ 10,221**
Add back (deduct) items not directly related to field operations:				
Realized foreign exchange gain	(139)	(100)	(149)	(619)
Finance expense (cash portion)	219	6	245	11
Risk management (gain) loss-realized	(207)	53	49	72
Administrative expenses	2,710	1,357	4,049	2,484
Field netback	**$ 9,816**	**$ 6,345**	**$ 20,545**	**$ 12,169**

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

During the period beginning on April 1, 2012 and ended on June 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:

- Eagle's 2012 capital budget and drilling and tie in plans;
- the Trust's expectation regarding its average working interest production for the full year 2012 and for the second half of 2012;
- the Trust's expectation regarding its 2012 operating costs;
- the Trust's expectation regarding its 2012 funds flow from operations, its sustainability and payout ratio targets, and sensitivities of the sustainability and payout ratios and funds flow from operations to production rates and commodity prices;
- commodity prices and exchange rates; and
- management's objective to maintain a debt to cash flow ratio below 1.5 times.

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.

EAGLE ENERGY TRUST

Eagle Energy Trust

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

For the six months ended June 30, 2012

Eagle Energy Trust

Condensed Consolidated Balance Sheets

(Thousands of Canadian dollars) (unaudited)

	Note		June 30, 2012		December 31, 2011
ASSETS					
Current assets					
Cash		**$**	8,648	$	7,495
Trade and other receivables			7,015		5,585
Prepaid expenses			148		305
Risk management asset	3		2,947		-
			18,758		**13,385**
Non-current assets					
Risk management asset	3		2,871		-
Exploration and evaluation			204		119
Oil and gas properties	11		268,770		145,067
Property, plant and equipment			178		127
Other intangible assets	12		492		187
			272,515		**145,500**
Total Assets		**$**	**291,273**	$	**158,885**
LIABILITIES					
Current liabilities					
Trade and other payables			14,225		5,926
Distributions payable	13		2,475		1,656
Unit-based payments	7		11,458		8,472
Risk management liability	3		-		503
			28,158		**16,557**
Non-current liabilities					
Long - term debt	14		24,129		-
Other long term liabilities			12		-
Deferred income tax	9		1,433		-
Provision for liabilities and other charges			1,618		502
			27,192		**502**
Total Liabilities		**$**	**55,350**	$	**17,059**
UNITHOLDERS' EQUITY					
Trust capital	15		264,537		168,175
Other reserves			1,053		(718)
Accumulated earnings (loss)			3,188		(4,427)
Accumulated cash distributions	13		(32,855)		(21,204)
Total Unitholders' Equity			**235,923**		**141,826**
Total Liabilities and Unitholders' Equity		**$**	**291,273**	$	**158,885**

See Note 18 "Commitments" and Note 19 "Subsequent events
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 June 30, 2012**	Three Months Ended June 30, 2011	**Six Months Ended June 30, 2012**	Six Months Ended June 30, 2011
Revenue	5	**$** 13,077	$ 7,304	**$** 27,024	$ 14,440
Cost of sales	6	8,818	3,543	17,115	7,744
Gross profit		4,259	3,761	9,909	6,696
Administrative expenses		2,737	1,357	4,098	2,484
Unit - based compensation (recovery)	7	(1,007)	2,130	2,998	4,905
Operating profit (loss)		**2,529**	**274**	**2,813**	**(693)**
Foreign exchange gain, net		139	100	149	619
Finance expense	8	(144)	(37)	(204)	(68)
Risk management gain (loss)	3	7,458	1,366	6,272	(66)
Earnings (Loss) before taxes		**9,982**	**1,703**	**9,030**	**(208)**
Income tax expense - deferred	9	1,415	-	1,415	-
Earnings (Loss)		**$ 8,567**	**$ 1,703**	**$ 7,615**	**$ (208)**
Other comprehensive income (loss)					
Foreign currency translation gain (loss)		4,979	(744)	1,771	(4,539)
Comprehensive income (loss)		**$ 13,546**	**$ 959**	**$ 9,386**	$ **(4,747)**
Earnings (Loss) per unit					
Basic	10	0.37	0.10	0.37	(0.01)
Diluted	10	0.33	0.10	0.37	(0.01)

The notes are an integral part of these condensed financial statements

Eagle Energy Trust

Condensed Consolidated Statements of Unitholders’ Equity

For the six months ended June 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**
Loss		-	-	-	(208)	-	(208)	(208)
Foreign currency translation loss		-	-	(4,539)	-	-	-	(4,539)
Comprehensive loss		-	-	(4,539)	(208)	-	(208)	(4,747)
Issuance of Trust capital		270	2,928	-	-	-	-	2,928
Trust unit issuance costs		-	(203)	-	-	-	-	(203)
Unitholder distributions		-	-	-	-	(9,503)	(9,503)	(9,503)
		270	2,725	-	-	(9,503)	(9,503)	(6,778)
Balance as at June 30, 2011		**17,894**	**162,302**	**(8,905)**	**(3,422)**	**(11,419)**	**(14,841)**	**138,556**
Balance as at December 31, 2011		**18,544**	**168,175**	**(718)**	**(4,427)**	**(21,204)**	**(25,631)**	**141,826**
Earnings		-	-		7,615	-	7,615	7,615
Foreign currency translation gain		-	-	1,771	-	-	-	1,771
Comprehensive income		-	-	1,771	7,615	-	7,615	9,386
Issuance of Trust capital	15	9,351	102,302	-	-	-	-	102,302
Trust unit issuance costs	15	-	(5,940)	-	-	-	-	(5,940)
Unitholder distributions	13	-	-	-	-	(11,651)	(11,651)	(11,651)
		9,351	96,362	-	-	(11,651)	(11,651)	84,711
Balance as at June 30, 2012		27,895	264,537	1,053	3,188	(32,855)	(29,667)	235,923

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 June 30, 2012**	Three Months Ended June 30, 2011	**Six Months Ended June 30, 2012**	Six Months Ended June 30, 2011
Cash flows from operating activities					
Net cash generated by operating activities	16	**$ 15,785**	$ 1,720	**$ 23,296**	$ 5,003
Cash flows from investing activities					
Additions to exploration and evaluation		(1)	(172)	(85)	(322)
Additions to oil and gas properties		(13,861)	(7,063)	(16,336)	(12,398)
Additions to property, plant and equipment		(18)	(33)	(99)	(60)
Acquisition of oil and gas assets	4	(115,680)	-	(115,680)	-
Net cash used in investing activities		**$ (129,560)**	$ (7,268)	**$ (132,200)**	$ (12,780)
Cash flows from financing activities					
Long-term debt		23,939	-	23,939	-
Proceeds from issuance of units		99,248	2,927	102,302	2,927
Trust unit issue costs		(5,912)	(88)	(5,940)	(203)
Cash distributions to unitholders		(5,836)	(4,751)	(10,833)	(9,819)
Deferred financing charges		(180)	-	(254)	-
Net cash provided by (used in) financing activities		**$ 111,259**	$ (1,912)	**$ 109,214**	$ (7,095)
Net (decrease) increase in cash and cash equivalents		**(2,516)**	**(7,460)**	**310**	**(14,872)**
Effects of exchange rates on cash and cash equivalents		1,009	(110)	843	(796)
Cash at beginning of the period		10,155	23,633	7,495	31,731
Cash at end of the period		**$ 8,648**	**$ 16,063**	**$ 8,648**	**$ 16,063**

The notes are an integral part of these condensed financial statements

Eagle Energy Trust

Notes to Condensed Consolidated Financial Statements (unaudited)

For the six months ended June 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 the 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: 9th Floor, 639-5th 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 August 9, 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 not only the relationship between the Canadian and United States dollars but also world economic events that dictate the levels of supply and demand.

The Trust enters into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Trust does not apply hedge accounting for these contracts. The Trust's production is 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 June 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.

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

	Volume	*Measure*	*Beginning*	*Term*	*Floor $US*	*Ceiling $US*	*Fair Value $000's*
Oil Fixed Price							
NYMEX (i)	200	bbls/d	Nov-11	Oct-12	91.00	91.00	183
NYMEX (ii)	500	bbls/d	Jan-12	Dec-12	92.00	105.00	879
NYMEX (ii)	300	bbls/d	May-12	Apr-13	95.00	108.25	1,064
NYMEX (i)	200	bbls/d	Jan-13	Apr-13	103.45	103.45	2,197
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	98.00	98.00	1,495
							$ 5,818

(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).

Earnings Impact of Realized and Unrealized Gain (Loss)
For the three months ended June 30, 2012

$000's	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Net Gain (Loss)
Net effect - risk management	**$ 207**	**$ 7,251**	**$ 7,458**

For the six months ended June 30, 2012

$000's	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Net Gain (Loss)
Net effect - risk management	**$ (49)**	**$ 6,321**	**$ 6,272**

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 $115,680,000, which includes closing adjustments of $1,165,734. 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 six months ended June 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 (purchase price allocation) as follows:

Identifiable assets acquired and liabilities assumed:		
Oil and Gas Properties	$	116,389
Decommissioning liabilities		(709)
	$	**115,680**

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 from external customers 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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Revenue before royalties	$ 18,340	$ 10,122	37,515	$ 19,988
Royalties	(5,263)	(2,818)	(10,491)	(5,548)
	$ 13,077	**$ 7,304**	**27,024**	**$ 14,440**

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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating costs related to the field	$ 3,260	$ 959	6,479	$ 2,271
Depreciation, depletion and amortization	5,558	2,584	10,636	5,473
	$ 8,818	**$ 3,543**	**17,115**	**$ 7,744**

7. Unit-based payments

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

$000's	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	
Units issued on performance option surrender	$ 24	$ 530	$ 735	$ 1,165	Note 7 (a)
Restricted unit rights	(551)	623	906	1,447	Note 7 (b)
Unit options	(390)	961	1,204	2,277	Note 7 (c)
Phantom unit rights	(90)	16	153	16	Note 7 (d)
Unit-based compensation expense (recovery)	**$ (1,007)**	**$ 2,130**	**$ 2,998**	**$ 4,905**	

Note (a)

Units issued upon surrender of performance options

At June 30, 2012, December 31, 2011 and June 30, 2011, there were 387,500 units outstanding.

At June 30, 2012, $2,865,569 (December 31, 2011 – $2,130,831, June 30, 2011 - $nil) was included in trade and other payables and $nil (December 31, 2011 - $nil, June 30, 2011 - $1,370,883) was included in other long-term liabilities relating to these units.

At June 30, 2012, the fair value of the units was assumed to be equal to the June 30, 2012 closing price of $9.76 per unit (December 31, 2011 - $10.05 per unit, June 30, 2011 - $11.30 per unit).

Note (b)

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

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

At June 30, 2012, $3,276,616 (December 31, 2011 - $2,370,407, June 30, 2011 - $nil) was included in trade and other payables and $nil (December 31, 2011 - $nil, June 30, 2011 – $1,611,091) was included in other long term liabilities relating to these RURs.

At June 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:

	June 30, 2012	December 31, 2011	June 30, 2011
Fair value at the balance sheet date	$ 5.58	$ 5.59	$ 6.64
Volatility	35%	35%	33%
Life of restricted unit rights	8.5 years	9.0 years	9.5 years
Risk-free interest rate	1.77%	1.98%	3.0%

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 June 30, 2012 and December 31, 2011 there were 1,706,000 options outstanding. The weighted average exercise price at June 30, 2012 was $8.35 per option (December 31, 2011 – $8.88 per option). At June 30, 2011, there were 1,342,500 options outstanding with a weighted average exercise price of $9.50.

At June 30, 2012, $4,957,386 (December 31, 2011 - $3,801,767, June 30, 2011 - $1,407,459) was included in trade and other payables and $nil (December 31, 2011 - $nil, June 30, 2011 - $1,172,882) was included in other long-term liabilities relating to this option plan.

The closing trading price of the Trust's units at June 30, 2012 was $9.76 per unit (December 31, 2011 - $10.05 per unit, June 30, 2011 - $11.30 per unit). At June 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:

	June 30, 2012	December 31, 2011	June 30, 2011
Fair value at the balance sheet date	$ 4.60	$ 4.73	$ 5.62
Unit price	$ 9.76	$ 10.05	$ 11.30
Exercise price	$ 8.35	$ 8.88	$ 9.50
Volatility	35%	35%	33%
Option life	8.6 years	9.1 years	9.4 years
Distributions – none estimated, declining strike price feature	0%	0%	0%
Risk-free interest rate	1.77%	1.98%	3.0%

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)

Phantom unit rights (PUR) plan

At June 30, 2012 and December 31, 2011 there were 185,000 phantom unit rights outstanding. At June 30, 2011, there were 80,000 phantom unit rights outstanding, since the plan was implemented June 14, 2011.

At June 30, 2012, $ 358,430 (December 31, 2011 - $217,620, June 30, 2011 - $8,791) was included in trade and other payables and $12,003 (December 31, 2011 - $nil, March 31, 2011 - $7,326) was included in other long-term liabilities relating to the PUR plan.

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

	June 30, 2012	December 31, 2011	June 30, 2011
Fair value at the balance sheet date	$ 4.28	$ 4.76	$ 5.52
Volatility	35%	35%	33%
Life of restricted unit rights	9.2 years	9.5 years	9.6 years
Risk-free interest rate	1.77%	1.98%	3.0%

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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Interest expense on long-term debt	$ 187	$ -	$ 187	$ -
Amortized application fees on long-term debt	(80)	20	(53)	37
Standby and bank fees	32	15	61	26
Accretion of decommissioning provision	5	2	9	5
Finance expense	$ 144	$ 37	$ 204	$ 68

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:

		Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Earnings (loss) before taxes		$ 9,982	$ 1,703	$ 9,030	$ (208)
Expected tax rate		35%	35%	35%	35%
Expected income tax expense (recovery)		3,494	596	3,161	(73)
Increase (Decrease) resulting from:					
Non-deductible items – permanent differences					
Administrative expenses of the Trust	35%	170	248	343	430
Unit-based compensation (recovery)	35%	(353)	746	1,049	1,717
Foreign exchange gain, net	35%	(49)	(35)	(52)	(216)
Risk management gain (loss)	35%	(2,610)	(475)	(2,195)	23
Changes in temporary differences for which no amounts are recognized	35%	515	(150)	(219)	(36)
Changes in temporary difference for which amounts are recognized	35%	1,433	-	1,433	-
Items deductible at the subsidiary level					
Interest on internal debt of subsidiary	35%	(1,139)	(930)	(2,068)	(1,849)
Other	35%	(46)	-	(37)	4
Income tax expense	35%	$ 1,415	$ -	$ 1,415	$ -

Deferred tax assets and liabilities:

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

	June 30, 2012	December 31, 2011
Deferred tax liabilities:		
Oil and gas properties in excess of tax value	$ 25,549	$ 13,118
Exploration and evaluation assets	-	-
	25,549	13,118
Less deferred tax assets:		
Non-capital losses – US based	(24,116)	(14,138)
Net deferred tax liability (asset) – before valuation allowance	1,433	(1,020)
Valuation allowance	-	1,020
Net deferred tax liability (asset)	$ 1,433	$ -

10. Earnings (Loss) per unit

000's	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Earnings (Loss) - basic	$ 8,567	$ 1,703	$ 7,615	$ (208)
Earnings (Loss) - diluted	$ 8,201	$ 1,703	$ 7,615	$ (208)
Weighted average units outstanding - basic	22,995	17,742	20,811	17,682

Weighted average units outstanding - diluted	24,706	17,742	20,811	17,682
Earnings (Loss) per unit - basic	**$ 0.37**	**$ 0.10**	**$ 0.37**	**$ (0.01)**
Earnings (Loss) per unit - diluted	**$ 0.33**	**$ 0.10**	**$ 0.37**	**$ (0.01)**

Calculation

Basic earnings (loss) per unit is calculated by dividing the earnings (loss) attributable to owners 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 dilutive equity instruments outstanding.

Per unit amounts

Diluted earnings per unit for the three months ended June 30, 2012 includes trust units issuable upon the exercise of unit options as well as trust units that were issued upon the surrender of performance options. Excluded from the three and six months ended June 30, 2011 and six months ended June 30, 2012 trust units outstanding is the effect of 1,706,000 (June 30, 2011 – 1,342,500) options as well as the 387,500 trust units issued to certain directors, Management and a consultant on the surrender of previously granted performance options. 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	129,963	3,270	1,107	134,340
Transfers from exploration and evaluation	-	-	-	-
At June 30, 2012	**$ 284,328**	**$ 6,626**	**$ 1,598**	**$ 292,552**
Accumulated depreciation				
At December 31, 2011	$ (12,555)	$ (590)	$ -	$ (13,145)
Charge for the period	(9,700)	(937)	-	(10,637)
At June 30, 2012	**$ (22,255)**	**$ (1,527)**	**$ -**	**$ (23,782)**
Net book value				
At December 31, 2011	$ 141,810	$ 2,766	$ 491	$ 145,067
Net change	120,263	2,333	1,107	123,703
At June 30, 2012	**$ 262,073**	**$ 5,099**	**$ 1,598**	**$ 268,770**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $136,549,280 (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, see note 4 "Acquisition".

12. Other intangible assets

$000's	**June 30, 2012**	December 31, 2011
Deferred financing charges	$ 541	$ 289
Accumulated amortization	(49)	(102)
Net other intangible assets	**$** 492	**$ 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	June 30, 2012	December 31, 2011	Cumulative
Beginning balance	$ 1,656	$ 1,916	$ -
Distributions declared	11,651	19,287	32,855
Less distributions paid	(10,833)	(19,547)	30,380
Outstanding distributions declared and payable	**$ 2,475**	**$ 1,656**	**$ 2,475**

Distributions are declared and paid monthly. The outstanding balance at June 30, 2012 represents the distribution declared June 15, 2012 and paid July 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.

As at June 30, 2012, $24,128,970 has been drawn under this $US 48.5 million credit facility by way of base rate loan. 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 which, if not cured or waived, would permit acceleration of the indebtedness pursuant to the credit facility. At June 30, 2012 there were no covenant violations.

15. Trust capital

Trust units outstanding	**June 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 capital pursuant to DRIP	671	6,822	920	8,961
Issuance of Trust capital [(1)]	8,680	95,480	-	-
Reclass from unit based compensation for option exercise	-	-	-	49
Trust Unit issuance costs	-	(5,940)	-	(412)
Ending balance	**27,895**	**$ 264,537**	**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 387,500 units issued to certain directors, management and a consultant on the surrender of previously granted performance options have been excluded from units outstanding as a result of IFRS principles which exclude 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

$000’s	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Income (loss) for the period	**$ 8,567**	$ 1,703	**7,615**	$ (208)
Adjustments for:				
Depreciation, depletion and amortization	5,584	2,593	10,685	5,488
Income tax expense - deferred	1,415	-	1,415	-
Unit-based compensation	(1,007)	2,130	2,998	4,905
Unrealized risk management gain	(7,251)	(1,419)	(6,321)	(6)
Finance expense	(75)	22	(41)	42
	7,233	5,029	**16,351**	10,221
Changes in working capital:				
Trade and other receivables	(791)	435	(1,407)	(2,474)
Prepaid expenses	54	(7)	156	(96)
Trade and other payables	9,289	(3,737)	8,196	(2,649)
	8,552	(3,309)	**6,945**	(5,219)
Cash generated from operations	15,785	1,720	23,296	5,003
Income taxes paid	-	-	-	-
Net cash generated by operating activities	**$ 15,785**	$ 1,720	**$ 23,296**	$ 5,003

Summary of non-cash items

$000’s	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating cash flow				
Income tax expense - deferred	$ 1,415	-	$ 1,415	-
Unit-based compensation	(1,007)	2,130	2,998	4,905
Distributions payable-declared not yet paid	2,475	1,600	2,475	1,600
Unrealized risk management gain	(7,251)	(1,419)	(6,321)	(6)
Investment activities				
Depreciation, depletion and amortization	$ 5,584	$ 2,593	$ 10,685	$ 5,488
Provision for decommissioning costs	1,091	61	1,107	111
Accretion of decommissioning provision	5	3	9	5
Financing activities				
Finance expense-amortization of deferred financing costs	$ (80)	$ 20	$ (50)	$ 37
Distributions accrued-declared not yet paid	(2,475)	(1,600)	(2,475)	(1,600)

17. Related party disclosures

The Trust has no party holding voting control.

Key management personnel

Key management personnel consist of the Chief Executive Officer (CEO), Chief Operating Officer (COO), Chief Financial Officer (CFO), 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 sub-leases 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 June 30, 2012 and December 31, 2011. For the six months ended June 30, 2012 administrative expenses included $51,000 (June 30, 2011 - $48,000) for amounts billed from this related party.

18. Commitments

Operating lease commitment – head office lease in Calgary, Alberta

The initial term of the sub-lease agreement was for six months from January 1, 2011 until June 30, 2011. On July 25th, 2011, the sub-lease 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 sub-lease were $51,000, with $nil remaining as at June 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 sub-lease approximate $US 338,400, with 15 months and approximately $US 169,000 remaining at June 30, 2012. In $CA the remaining future minimum lease payments approximate $172,300 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.0181.

Operating lease commitment – office lease in Luling, Texas

The 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 31, 2015 with a monthly rate of $1,650. Future minimum payments during the term of the sub-lease and the extension approximate $US 80,000, with $US 62,700 remaining at June 30, 2012. In $CA, the remaining future minimum lease payments approximate $ 63,800 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.0181.

Drilling rig commitment – nine wells

The Trust, through its operations in the Salt Flat Field, entered into a nine well drilling rig commitment agreement. At June 30, 2012, seven wells have been drilled under the agreement. Future minimum payments are estimated to be approximately $US 1,100,000 which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 880,000 with $US 202,000 remaining at June 30, 2012. In $CA the remaining net future commitment approximates $205,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.0181.

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.

19. Subsequent events

Commodity Hedging

The Trust has entered into the following financial contracts to further mitigate the effects of fluctuating prices on a portion of its production as follows:

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.

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.

Drilling rig commitment – six wells

The Trust, through its operations in the Permian Basin, (see note 4, "Acquisition") entered into a six well drilling rig commitment agreement effective July 23, 2012. 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. In $CA the net future commitment approximates $3.2 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.0181.

Drilling rig commitment – eight wells

The Trust, through its operations in the Salt Flat Field, amended its current nine well drilling rig commitment agreement to include an additional eight well drilling rig commitment effective July 27, 2012. Future minimum payments of 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. In $CA the remaining net future commitment approximates $1.2 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.0181.