VISION GROWTH INCOME

2011 Financial Report

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Letter to Our Unitholders

The past 16 months since Eagle completed its ground-breaking IPO have been challenging and rewarding. At our current unit price of about $11.00, we have delivered a total annual return to our unitholders of over 20%. We have paid each of our monthly distributions on time and in the amount expected. We are positioned to continue paying monthly distributions for many years going forward.

Our decision to focus on an oil asset for our IPO acquisition has proven to be a wise one; oil prices are almost 40% higher than when we agreed to buy the Salt Flat Field in Texas. We have taken over all aspects of the operation of this property. Our team has grown from three people in November 2010, to 25 people today. In one year, we have assembled solid operational, financial and business development teams at Eagle. Our management now has control over our entire business, from field operations and drilling, finance and reporting, through to pursuing acquisitions and future growth strategies. I am proud of the work our team has done to accomplish so much in one year.

Having said this, 2011 was not without its challenges. Our industry has never experienced such a wide distance between the relative values of oil and natural gas. This situation has resulted in the transactions market for oil and liquids focused assets becoming increasingly competitive. In addition, capital markets were inconsistent and unsettled during much of 2011, with European debt issues leading the charge. Eagle also experienced a few business challenges, including delays in bringing new wells on production due to regulatory overload in Texas. Together, these factors made it necessary for Eagle to assume field operations about a year earlier than planned.

Notwithstanding these issues, Eagle's performance has been strong and we have demonstrated our ability to overcome challenges, solve complex issues, and create value for our unitholders.

We have grown Eagle's production by over 800% in the 18 months since the effective date of the Salt Flat acquisition. At current oil prices and our production guidance levels, we will funds flow over $40 million in 2012. We have no debt, and a $31 million borrowing facility. Our existing assets require less than half of our funds flow to replace declines and grow by about 10%. As I write this letter, we have over $5 million in cash on hand.

We aim to grow our business significantly this year, but will remain disciplined in our approach to new acquisitions. Our balance sheet is ready and our management team is prepared.

Sincerely,
Richard W. Clark
President and Chief Executive Officer
March 22, 2012

Management's Discussion and Analysis

March 22, 2012

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

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

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

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

Non-IFRS financial measures

Statements throughout this MD&A make reference to the terms "field netback" and "funds flow from operations" which are non-IFRS financial measures that do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that "field netback" and "funds flow from operations" provide useful information to investors and management since such measures reflect the quality of production, the level of profitability, the ability to drive growth through the funding of future capital expenditures and the sustainability of distributions to unitholders. Funds flow from operations is calculated before changes in non-cash working capital. 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, for $127.1 million. Consideration consisted of cash and 2,000,000 trust units valued at $20 million.

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.

2010 Comparative financial information

The Trust was formed on July 20, 2010. The Trust officially commenced active business operations, including closing its initial public offering and acquiring interest in the Salt Flat Field on November 24, 2010. Therefore, financial information presented in this MD&A for the year ended December 31, 2010 has limited usefulness for comparison purposes.

Highlights for the three months and year ended December 31, 2011

- Assumed operatorship of the Salt Flat Field in Texas on August 18, 2011 and opened a field office in Luling, Texas.
- Added engineering, field and accounting staff throughout the year to assist with full cycle development of the Salt Flat Field, acceleration of the strategic focus on potential new acquisitions and management of planned activities.
- 21 (16.8 net) horizontal oil wells drilled during the year and 26 (20.8 net) horizontal oil wells tied in and brought on stream during the year.
- Total proved and probable reserves of approximately 7,674 Mbbls of oil, 48% of which are categorized as proved.
- Total reserve additions of 1,101 Mbbls since December 31, 2010, resulting in a reserves replacement ratio of 220% of Eagle’s volumes produced from January 1, 2011 to December 31, 2011.
- Fourth quarter average working interest sales volumes of 2,023 (2011 average – 1,376) barrels of oil per day, up from third quarter volumes of 995 barrels of oil per day.
- Fourth quarter funds flow from operations of $7.2 million ($38.69 per barrel or $0.39 per unit), up approximately 300% from $2.4 million in the third quarter ($26.55 per barrel or $0.14 per unit).
- 2011 funds flow from operations of $19.9 million ($39.52 per barrel or $1.11 per unit).
- Fourth quarter field netbacks of $47.82 (2011 average - $50.06) per barrel.
- No bank debt, an expanded $US 31.0 million credit facility (based on the 2011 independent reserves evaluation).
- 2011 unitholder distributions of $1.05 per unit ($0.0875 per unit per month).

Selected annual information

The following table shows selected information for the Trust’s fiscal year ended December 31, 2011 and the initial fiscal year ended December 31, 2010.

Year ended December 31	**2011**	2010[(1)]
($ except per unit amounts and production)		
Sales volumes – bbls per day (100% light oil)	**1,376**	726
Revenue, net of royalties	**31,771,486**	1,366,494
Funds flow from operations	**19,852,742**	(288,076)
per unit – basic & diluted	**1.11**	(0.07)
Loss	**(1,213,585)**	(3,213,531)
per unit – basic & diluted	**(0.07)**	(0.81)
Current assets	**13,385,848**	33,102,821
Current liabilities (including non-cash unit-based compensation)	**16,557,250**	9,061,984

Year ended December 31	**2011**	2010[1]
($ except per unit amounts and production)		
Total assets	**158,885,807**	159,868,227
Total non-current liabilities	**502,431**	724,833
Unitholders' equity	**141,826,126**	150,081,410
Cash distributions declared	**19,287,163**	1,916,432
per issued unit	**1.05**	0.1064
Units outstanding for accounting purposes	**18,543,599**[2]	17,624,081[2]
Units issued	**18,931,099**	18,011,581

Notes:

(1) The Trust commenced operations on November 24, 2010 after it closed its initial public offering and acquired its interest in the Salt Flat Field.

(2) Units outstanding for accounting purposes excludes 387,500 units issued due to the performance conditions that have to be met to enable such units to be released from escrow.

Results of operations

Revenue

	Three Months Ended December 31, 2011	**Year Ended December 31, 2011**	**Year Ended December 31, 2010**
Sales volumes – bbls per day (100% light oil)	**2,023**	**1,376**	726

	Three Months Ended December 31, 2011		**Year Ended December 31, 2011**		**Year Ended December 31, 2010**	
	$	**/bbl**	**$**	**/bbl**	$	/bbl
Benchmark WTI ($US)		94.17		95.00		89.20
Realized sales price ($US)		87.89		88.64		83.09
Differential to benchmark ($US)	$	6.28	$	6.36		6.11
Oil sales before royalties		88.89		87.95		83.73
Royalties		(25.57)		(24.73)		(22.99)
Revenue	**$**	**63.32**	**$**	**63.22**	$	60.74

The growth in fourth quarter average sales volumes when compared to the full year 2011 average is due to substantially all of the 26 (20.8 net) tie ins taking place during the final four months of 2011.

There is a quality differential between the benchmark West Texas Intermediate (“WTI”) price and the sales price realized by Eagle. The Trust’s wholly-owned subsidiary in the US (“Eagle”) has secured transportation and marketing agreements and continues to monitor these differentials to ensure that volumes will be marketed at differentials to the WTI posted price which are deemed by management to be optimal.

The benchmark WTI price increased 5% from third quarter 2011, with $US realized prices and Canadian dollar realized prices increasing by a commensurate amount. Not included in this figure is a realized loss on commodity contracts of $9,290 ($0.05 per barrel) for the three month period and a realized gain of $43,017 ($0.09 per barrel) for the year. See *Realized and unrealized risk management gain/loss.*

The overall royalty rate of approximately 28% was consistent with prior periods.

Cost of sales

	Three Months Ended December 31, 2011		Year Ended December 31, 2011		Year Ended December 31, 2010	
	$	**/bbl**	**$**	**/bbl**	$	/bbl
Transportation		2.01		1.99		2.02
Other operating costs		13.49		11.17		10.25
	$	15.50	$	13.16		12.27
Depreciation, depletion and amortization		25.90		25.01		25.84
Cost of sales	**$**	**41.40**	**$**	**38.17**	$	38.11

Fuel and power, utilities and equipment rentals (generators) account for 57% of operating costs on a year to date basis. Fourth quarter per barrel operating costs include $4.63 per barrel ($1.72 per barrel year to date) relating to increased power consumption attributed to the twelve (9.6 net) wells brought on stream in late September. The use of diesel generators to produce these wells is temporary, pending permanent power installation.

Fourth quarter per barrel operating costs include charges of $1.41 per barrel ($0.52 per barrel year to date) relating to annual *ad valorem* (property) taxes.

The depletion, depreciation, and amortization provision for the periods ended December 31, 2011 are based on proved plus probable reserves, including the future development costs associated with those reserves, as found in the year end 2011 reserves evaluation report prepared by the Trust's independent reserves evaluators.

Field netback

	Three Months Ended December 31, 2011				Year Ended December 31, 2011				Year Ended December 31, 2010			
	$		**$**	**/bbl**	**$**		**$**	**/bbl**	$			
Oil sales before royalties		16,540,623		88.89		44,180,632		87.95		1,883,589		83.73
Royalties		(4,757,689)		(25.57)		(12,424,275)		(24.73)		(517,095)		(22.99)
Transportation		(373,898)		(2.01)		(992,667)		(1.99)		(45,340)		(2.02)
Other operating costs		(2,510,617)		(13.49)		(5,613,637)		(11.17)		(230,513)		(10.25)
Field netback	**$**	**8,898,419**	**$**	**47.82**	**$**	**25,150,053**	**$**	**50.06**	$	1,090,641	$	48.47
Sales volumes (bbls per day)				**2,023**				**1,376**				726

During the quarter, benchmark WTI averaged $US 94.17 per barrel and the Trust realized a field netback of $47.82 per barrel. On a year to date basis, benchmark WTI averaged $US 95.00 per barrel, which yielded a field netback of $50.06 per barrel.

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 costless collar for 200 bbls of oil per day with a February 2011 through January 2012 term at a floor of $US 85.00 per barrel and a ceiling of $US 100.00 per barrel; (ii) a costless collar for 200 bbls of oil per day with a May 2011 through April 2012 term at a floor of $US 88.00 per barrel and a ceiling of $US 107.55 per barrel; (iii) a fixed contract to sell 100 bbls of oil per day with a May 2011 through April 2012 term at a price of $US 101.00 per barrel; (iv) 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; (v) a costless collar 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; and (vi) a costless collar 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.

A sharply stronger forward commodity pricing environment caused a decrease in the future value of these contracts and a swing from a net asset to a net liability position during the fourth quarter. 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 $1,679,824 unrealized risk management loss was recorded for the quarter (a $503,121 unrealized risk management loss for the year). For the quarter, the Trust also realized a $9,290 risk management loss (a $43,017 realized risk management gain for the year).

Administrative expenses

Total administrative expenses for the fourth quarter were $1,800,387, approximately $311,000, or 21%, above third quarter levels. This increase related to the year end bonus accrual being partially offset by higher overhead recoveries and lower consulting fees. Throughout the year, engineering, field and accounting staff were added to assist with full cycle development of the Salt Flat Field, acceleration of the strategic focus on potential new acquisitions and management of planned activities. Staff and related costs account for 69% of annual administrative expenses.

Unit-based compensation

Non-cash unit-based compensation expense of $2,071,526 ($7,847,492 year to date) was recorded during the fourth quarter as an additional liability. The components of the expense related to (i) the estimated fair value of escrowed units and restricted unit rights that were previously issued upon surrender of performance options ($976,000 for the quarter, $4.1 million for the year); (ii) the estimated fair value of options granted under the option plan ($979,000 for the quarter, $3.5 million for the year); and (iii) the estimated fair value of phantom unit rights granted under the phantom unit rights plan ($116,000 for the quarter, $217,000 for the year).

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 and 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 increase in the liability and associated expense from December 31, 2010 to December 31, 2011 was primarily due to: (i) the passage of time, since unit-based compensation expense is recorded in the income statement over the vesting periods of the awards; and (ii) an increase in the year over year volatility assumption of Eagle’s units from 25% to 35%. With respect to the quarterly expense, since Eagle’s December 31, 2011 unit price was higher than its September 30, 2011 unit price ($10.05 per unit versus $9.72 per unit, respectively) fourth quarter unit-based compensation expense was higher than the amount recorded in the third quarter.

Tax horizon

The tax horizon, as determined from a full cycle corporate model incorporating cash flows from the year end reserves evaluation report plus all applicable U.S. deductions, indicates that no material U.S. taxes are expected to be payable in respect of income attributable to the Salt Flat interest 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

	Q4/2011	Q3/2011	Q2/2011	Q1/2011	Q4/2010
($ except for bbls per day amount)					
Sales volumes – bbls per day (100% light oil)	2,023	995	1,214	1,269	726
Revenue, net of royalties	11,798,064	5,533,425	7,304,580	7,135,417	1,366,494
per bbl	63.40	60.42	66.10	62.49	60.72
Funds flow from operations	7,199,478	2,431,585	5,029,348	5,192,332	(288,076)
per bbl	38.69	26.55	45.52	45.47	(2.80)
per unit – basic & diluted	0.39	0.14	0.28	0.29	(0.07)

	Q4/2011	Q3/2011	Q2/2011	Q1/2011	Q4/2010
($ except for bbls per day amount)					
Income (loss)	(1,426,402)	420,694	1,703,134	(1,911,011)	(3,213,531)
per unit – basic & diluted	(0.08)	0.02	0.10	(0.11)	(0.81)
Cash distributions declared	4,936,356	4,847,582	4,775,185	4,728,040	1,916,432
per issued unit	0.2625	0.2625	0.2625	0.2625	0,1064
Current assets	13,385,848	14,121,037	20,067,295	27,919,736	33,102,821
Current liabilities	16,557,250	12,022,974	7,298,958	11,712,277	9,061,984
Total assets	158,885,807	164,479,546	150,350,547	154,137,632	159,868,227
Total non-current liabilities	502,431	2,670,910	4,495,664	2,893,127	724,833
Unitholders' equity	141,826,126	149,785,662	138,555,925	139,532,228	150,081,410
Units outstanding for accounting purposes	18,543,599(1)	18,174,580(1)	17,894,470(1)	17,624,081(1)	17,624,081(1)
Units issued	18,931,099	18,562,080	18,281,970	18,011,581	18,011,581

Note:

(1) 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 barrels per day of oil temporarily shut in due to delays in obtaining Texas Commission on Environmental Quality permits, production has grown commensurate with well tie-ins. All shut-in production was reinstated in October 2011. A total of 26 (20.8 net) wells were tied in and brought on stream during 2011. Of that total, 22 (17.6 net) wells were tied in from late September 2011 onward, thus contributing to the growth in volumes from the third quarter to fourth quarter 2011.

Funds flow from operations grows as sales volumes increase, and on a per-barrel 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.

A total of 21 (16.8 net) horizontal oil wells were drilled in the Salt Flat Field during 2011, with a 100% success rate; and 6 (4.8 net) salt water disposal wells were also drilled. During the fourth quarter, one (0.8 net) horizontal oil well was drilled in the Salt Flat Field, with a 100% success rate; and one (0.8 net) salt water disposal well was also drilled.

Liquidity and capital resources

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

Management's objective is to maintain a bank debt to cash flow ratio below 1.5 times.

The Trust believes that its expected funds flow from operations and 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 barrel basis:

	Three Months Ended December 31, 2011		**Year Ended December 31, 2011**		Year Ended December 31, 2010	
	$	**$ /bbl**	**$**	**$ /bbl**	$	
Field netback	8,898,419	47.82	25,150,053	50.06	1,090,641	48.47
Administrative expenses [(1)]	(1,782,126)	(9.57)	(5,727,972)	(11.40)	(1,374,830)	(61.11)
Realized risk management gain (loss)	(9,290)	(0.05)	43,017	0.09	(992,000)	(44.09)
Finance expense	(21,872)	(0.12)	(66,681)	(0.13)	(4,529)	(0.20)
Realized foreign exchange gain[(2)]	99,217	0.53	439,195	0.87	992,642	44.12
Interest income	15,130	0.08	15,130	0.03	-	-
Funds flow from operations	**$ 7,199,478**	**$ 38.69**	**$ 19,852,742**	**$ 39.52**	$ (288,076)	$ (12.81)

Notes:

(1) On a go-forward basis, per barrel 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 December 31, 2011, the Trust had no debt and had available a $US 16.5 million credit facility, indirectly through its U.S. subsidiary, with a U.S. affiliate of a Canadian chartered bank. Effective March 16, 2012, the borrowing base under the credit facility was increased to $US 31 million, with all other terms and conditions remaining unchanged.

Working capital

At December 31, 2011, the Trust had a working capital deficiency of $3.2 million (which becomes a $5.3 million surplus when the non-cash current portion of unit-based compensation is excluded) and no amounts drawn on its bank credit facility described above.

Unitholders’ equity

Other than the issuance of 10,000 units for proceeds of $91,200 relating to the exercise of Trust unit options, all other issuances of Trust capital were issued pursuant to the distribution reinvestment plans as detailed below. Management may seek to issue additional units in the future to provide sufficient capital to fund growth, including acquisition opportunities.

As a result of implementing its Premium Distribution™ and Distribution Reinvestment Plan in the second quarter, the Trust received proceeds resulting from the issuance of units from treasury to those unitholders who have opted to participate in the Plan. For the three months ended December 31, 2011, 359,019 units were issued (909,518 units for the year ended December 31, 2011) for total proceeds of approximately $3.1 million ($8.9 million for the year ended December 31, 2011) at an average price of $8.65 per unit ($9.75 per unit for the year ended December 31, 2011).

Distributions and outstanding unit data

The Trust pays monthly distributions to unitholders at the discretion of the Board of Directors. Distributions paid in the fourth quarter (for the September, October, and November 2011 record dates) totaled approximately $4.9 million ($19.5 million for the December 2010 through to November 2011 record dates).

At December 31, 2011, the Trust had issued 18,931,099 units. For purposes of the December 31, 2011 consolidated financial statements, 18,543,599 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, 19,137,518 units are issued and 1,706,000 options are outstanding.

Capital expenditures

Capital spending during the fourth quarter of 2011 and for the year ended December 31, 2011 was as follows:

	Three Months Ended December 31, 2011	**Year Ended December 31, 2011**	Year Ended December 31, 2010
	$	**$**	$
Exploration and evaluation	-	119,300[1]	-
Acquisition of the Salt Flat Field interest (adjustment)	10,325	(153,734)	127,139,361
Intangible drilling and completions	2,085,171	19,938,315	1,844,558
Well equipment and facilities	878,509	7,311,581	1,199,775
Other	16,568	133,679	125,249
	$ 2,990,573	$ 27,349,141	$ 130,308,943

Note:

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

During early 2011, the final statement of adjustments pursuant to the November 24, 2010 acquisition of the Salt Flat Field interest was prepared and resulted in an approximate $154,000 credit to Eagle.

A total of 21 (16.8 net) horizontal oil wells were drilled in the Salt Flat Field during 2011, with a 100% success rate; and 6 (4.8 net) salt water disposal wells were also drilled. In addition, 26 (20.8 net) wells were tied in and brought on stream and four recompletions were performed during the year.

During the fourth quarter, one (0.8 net) horizontal oil well was drilled in the Salt Flat Field, with a 100% success rate; and one (0.8 net) salt water disposal well was also drilled. In addition, ten (8.0 net) wells were tied in during the quarter and brought on stream.

Related infrastructure investment, including oil batteries and construction of a power trunk line continued throughout the fourth quarter. Phases 1 and 2 of the power trunk line project were tied in and on line mid-November 2011. As a result four generators were redeployed to wells at the north end of the Salt Flat Field. The remaining objective is to remove all generators currently in use as soon as possible to reduce operating costs. Phase 3 construction of the power trunk line project is underway with a new primary meter planned to allow tie in of the wells to the south. Discussions are underway to install a new meter to service the north half of the field.

Year end reserves information

On February 10, 2012, the Trust announced the results of the December 31, 2011 independent reserves evaluation that was conducted by GLJ Petroleum Consultants Ltd. ("GLJ") and prepared in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities.*

2011 Year end reserves report - highlights

- Total proved and probable reserves of approximately 7,674 Mbbls of oil, 48% of which are categorized as proved.
- Total reserve additions of 1,101 Mbbls since December 31, 2010, resulting in a reserves replacement ratio of 220% of Eagle's volumes produced from January 1, 2011 to December 31, 2011.
- A US$7.9 million increase in proved plus probable reserves value since December 31, 2010, after having produced 501.1 Mbbls in 2011.
- Total reserve additions of 1,420 Mbbls over the 19 months since the June 1, 2010 effective acquisition date of the Salt Flat Field, resulting in a reserves replacement ratio of 237% of Eagle's volumes produced from June 1, 2010 to December 31, 2011.
- A current reserve life index of 8.1 years, based on Eagle's 2012 average working interest production guidance of 2,600 bbls/day.
- 100% of the reserves are light oil.

The following tables summarize the independent reserves estimates and values as at December 31, 2011:

Summary of oil reserves

Reserves Category	Company Gross[1] *(Mbbls)*
Proved	
Developed Producing	2,200
Developed Non-Producing	45
Undeveloped	1,440
Total Proved	3,685
Probable	3,989
Total Proved Plus Probable	7,674

Note:

(1) Gross reserves are Eagle's total working interest share before the deduction of any royalties. Eagle owns no overriding royalty interests.

Summary of net present value of future net revenue of oil reserves

	Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year) [1]				
Reserves Category	0%	5%	10%	15%	20%
	(US$000)	(US$000)	(US$000)	(US$000)	(US$000)
Proved					
Developed Producing	87,765	76,894	68,916	62,792	57,924
Developed Non-Producing	1,519	1,352	1,218	1,109	1,019
Undeveloped	43,246	35,038	29,099	24,649	21,219
Total Proved	132,531	113,284	99,233	88,550	80,162
Probable	145,454	106,679	81,982	65,286	53,444
Total Proved Plus Probable	277,985	219,963	181,215	153,836	133,605

Notes:

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

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

(3) Present values of estimated future net revenue shown above are based on GLJ's escalated price forecast as of December 31, 2011, which assumes a base 2012 oil price of US$97.00/bbl.

(4) Totals may not add due to rounding.

Capital program efficiency

During 2011, Eagle's capital expenditures resulted in proved plus probable reserve additions of 1,101 Mbbls at a finding and development cost (including changes in future development costs) of $25.35 per bbl. Proved reserve additions in 2011 were 1,137 Mbbls which were added at a finding and development cost (including changes in future development costs) of $23.93 per bbl. Eagle's 2011 exploration and development expenditures were $27.2 million. The efficiency of Eagle's capital program for the year ended December 31, 2011, and the method of calculating finding and development costs, is shown in the following table.

	2011		2010	
	Proved	**Proved plus Probable**	Proved	Proved plus Probable
Exploration and Development expenditures ($000) [(1)]	27,215	27,215	2,995	2,995
Acquisitions ($000) [(2)]	-	-	127,279	127,279
Change in future development capital ($000)				
Exploration and Development	(18)	741	-	-
Acquisitions	-	-	24,213	54,649
Reserves Additions (Mbbls)				
Exploration and Development	1,137	1,101	240	312
Acquisitions	-	-	2,833	6,784
	1,137	1,101	3,073	7,096
Finding and Development Costs ($/bbl) [(1)(8)]				
Including change in FDC [(3)]	23.93	25.35	12.48	9.60
Excluding change in FDC	*23.94*	*24.68*	*12.48*	*9.60*
Finding, Development & Acquisitions Costs ($/bbl) [(1)(4)]				
Including change in FDC [(3)]	23.93	25.35	50.27	26.06
Excluding change in FDC	*23.94*	*24.68*	*42.39*	*18.36*
Recycle Ratio [(5)]	2.1x	2.0x	1.0x	1.9x
Reserves Replacement [(6)]	226%	220%	13,600%	31,399%
Reserve Life Index (yrs) [(7)]	3.9	8.1	6.3	14.6

Notes:

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

(2) Acquisition costs related to the 2010 asset acquisition of the Salt Flat Field.

(3) Calculation includes changes in future development costs (“FDC”).

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

(5) The 2011 recycle ratio is calculated using Eagle’s 2011 operating netback of $50.06 per bbl (2010 - $48.47 per bbl), see the Field Netback section of this MD&A.

(6) The reserves replacement ratios in 2010 are significantly higher than in 2011 because production was disproportionately lower due to a short period of initial operations in 2010 and reserves additions were disproportionately higher due to a significant acquisition in 2010.

(7) The 2011 reserve life index calculation is based on Eagle’s 2012 average working interest production guidance of 2,600 bbls/d. The 2010 reserve life index calculation was based on Eagle’s 2010 exit rate production of 1,327 bbls/d.

(8) The Finding and Development Costs increased in 2011 from 2010 due to the substantially higher investment in facilities and infrastructure in 2011.

Commitments

The Trust has committed to future payments as follows:

	Total $	Less than 1 year	1 – 3 years	After 3 years
Operating leases [(1)(2)(3)]	262,855	159,599	103,256	-
Purchase obligation [(4)(6)]	1,090,000	1,090,000	-	-
Settlement agreement [(5)]	61,000	61,000		
Total contractual obligations	**$ 1,413,855**	**$ 1,310,599**	**$ 103,256**	**-**

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. Future minimum lease payments during the six month renewal term are $51,000. 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 are $51,000, with $8,500 remaining as at December 31, 2011.

(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 21 months and approximately $US 236,900 remaining at December 31, 2011. In $CA the remaining future minimum lease payments approximate $240,900 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.017.

(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. Future minimum payments during the term of the sub-lease are $US 20,600, with $US 13,200 remaining at December 31, 2011. In $CA, the remaining future minimum lease payments approximate $13,400 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.017.

(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 December 31, 2011, no wells had been drilled under the agreement. Future minimum payments are estimated to be approximately $US 1,340,000, which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 1,072,000. In $CA the net future commitment approximates $1,090,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.017.

(5) The Trust, through its operations in the Salt Flat Field, signed a settlement agreement with a third party relating to damages in the producing formation of nearby wells. Future costs are estimated to be $US 75,000, which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 60,000. In $CA the net future commitment approximates $61,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.017.

(6) The Trust, through its operations in the Salt Flat Field, entered into a two well drilling rig commitment agreement effective February 13, 2012. This is in addition to the drilling rig commitment agreement effective December 15, 2011. Future minimum payments are estimated to be approximately $US 255,000, which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 204,000. In $CA the net future commitment approximates $207,400 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.017.

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 December 31, 2011 and December 31, 2010. For the year ended December 31, 2011 administrative expenses included $99,000 (December 31, 2010 - $3,250) for amounts billed from this related party.

Critical accounting estimates

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

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

Estimation of oil and gas reserves

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

Capitalized exploration and evaluation expenditures

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

Decommissioning provision

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

Impairment calculations

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

Income taxes

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

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

Derivative financial instruments

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

Classification of trust units as equity

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

Contingencies

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

Unit-based compensation

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

Accounting standards and interpretations issued but not yet adopted:

At the date of this MD&A, the following standards and interpretations, which have not been applied in these financial statements, were issued by the IASB but not yet in effect. The Trust will be required to adopt these new pronouncements, subject to the comments below regarding IFRS 9, as of January 1, 2013.

- IFRS 7 — "Financial Instruments: Disclosures"
- IFRS 9 — "Financial Instruments" (adoption for annual periods beginning on or after January 1, 2015)
- IFRS 10 — "Consolidated Financial Statements"
- IFRS 11 — "Joint Arrangements"
- IFRS 12 — "Disclosures of Interests in Other Entities"
- IFRS 13 — "Fair Value Measurement"

Although it is anticipated that the adoption of the above standards and interpretations should not have a material impact on its consolidated financial statements, the Trust is assessing the exact impact. The exact impact will depend on the individual transaction concerned, with potentially different amounts being recognized in the consolidated financial statements than would have previously been the case.

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

Risk management

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

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

Credit risk is the risk of financial loss to the Trust if a 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 December 31, 2011, the Trust had a working capital deficiency of $3.2 million (which becomes a $5.3 million surplus when the non-cash current portion of unit-based compensation is excluded) and no amounts drawn on its $US 16.5 million bank credit facility (which was increased to $31.0 million subsequent to year end). 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. There have been no draws against the credit facility during the year ended December 31, 2011 and no amounts were outstanding under the credit facility as of December 31, 2011 and December 31, 2010. The Trust therefore had no interest rate risk, and as a result, did not hedge against any interest rate exposures.

Outlook

This section includes forward looking information. Refer to the Note about Forward Looking Statements at the end of this MD&A.

On December 5, 2011, the Trust announced its 2012 capital program, production guidance, operating budget and a discussion regarding the sustainability of its distributions.

Highlights

- Distributions sustainable for over 3 years.
- 2012 capital budget of US$14 million, consisting of:
  - 10 (8.0 net) horizontal oil wells
  - 2 (1.6 net) side track re-entry wells
  - 1 (0.8 net) salt water disposal well
  - 1 new battery and adding to an existing battery
  - completing the electrification of the balance of the Salt Flat Field.

- Guidance 2012:
  - average working interest production of 2,600 barrels of oil per day
  - funds flow from operations of $40 million at $88 WTI pricing
  - payout ratio of 50% at $88 WTI pricing
  - operating costs ranging from $11.25 to $11.75 per barrel

Eagle's strategy to accelerate capital spending and production in 2010 and 2011 and then move to a more sustainable level of development is being realized on the Salt Flat Field. A sufficient level of investment has now been made in the field to achieve the Trust's targeted 50% payout ratio for 2012, while fully funding distributions and growing production by about 10%. To accomplish this, Eagle's required annual capital investment in this field over the next three years is approximately 50% of what was invested in 2011.

At current guidance levels of production, revenue and costs, Eagle anticipates drilling at least 12 wells per year, paying expenses and maintaining distributions in cash at the current rate of $1.05 per unit per year. Based on the December 31, 2011 independent reserves evaluation, 36 wells remain in Eagle's currently booked inventory.

Over 60% of the Trust's unitholders elect to receive their monthly distributions within the Trust's distribution reinvestment and Premium Drip™ programs. At this level of participation, approximately $12 million per year of Eagle's total distribution payments are reinvested by participants in units of the Trust. It is anticipated that this capital will be used to fund development and future growth opportunities.

At US$88 per barrel WTI and operating costs of between $11.25 and $11.75 per barrel, Eagle will have sufficient funds flow from operations and sufficient drilling inventory to replace declines, grow its production levels by 7 to 10% annually and sustain the cash payment of its distributions. More details around sensitivities are set out below.

2012 Capital budget

Eagle has approved a 2012 capital budget of US$14 million. Eagle intends to invest these funds in drilling 10 (8.0 net) new horizontal production wells, 2 (1.6 net) side track re-entry horizontal wells and 1 (0.8 net) salt water disposal well, constructing one battery, adding to an existing battery and completing the extension of the power trunk line to bring electrical power to the balance of the Salt Flat Field.

As a result, Eagle expects to achieve 2012 working interest average production of 2,600 barrels per day of light oil and operating costs of $11.25 to $11.75 per barrel. The capital budget excludes corporate and property acquisitions, which are evaluated separately on their own merits.

Sustainability of distributions

Eagle's strategy for the Salt Flat Field is to attain a sustainability ratio below 100% for the years 2012 to 2014. Eagle calculates this ratio as follows:

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

Eagle's 2012 pricing assumption for West Texas Intermediate oil is US$88/bbl.

Based on Eagle's 2012 average production rate guidance of 2,600 barrels of oil per day, management estimates 2012 funds flow from operations to be approximately $40 million. Management anticipates that, based on current levels of drilling and operating costs, an annual capital budget of US$14 million should be sufficient to fully offset production declines and grow 2012 average annual production by approximately 10% over the Trust's 2011 exit rate.

Eagle estimates it has a current inventory of locations sufficient to continue drilling on the Salt Flat Field for at least three more years. Assuming current operating and administrative cost levels, and a commodity price of $88 WTI, the Trust believes it can sustain its current level of distributions for at least 3 years at sustainable payout ratios.

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

Payout ratio

Eagle's 2012 payout ratio is expected to be approximately 50%. This is based on Eagle's 2012 pricing assumption for West Texas Intermediate oil of US$88/bbl and 2012 average production rate guidance of 2,600 barrels per day. Since inception, Eagle's strategy has been to move toward a 50% payout ratio. Eagle calculates this ratio as follows:

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

Sensitivities of Eagle's 2012 expected payout and sustainability ratios to production and pricing changes

The following tables describe the sensitivity of Eagle's payout and sustainability ratios to production levels and commodity prices. Eagle's 2012 pricing assumption for West Texas Intermediate oil is US$88/bbl and its 2012 average production rate guidance is 2,600 barrels per day.

Sensitivity of Payout Ratio to Production and Commodity Price

		2012 Average WTI		
		$75.00	**$88.00**	**$95.00**
2012 Average WI Production (bbls per day)	**2,400**	62%	55%	50%
	2,600	57%	50%	46%
	2,800	52%	46%	42%

Sensitivity of Sustainability Ratio to Production and Commodity Price

		2012 Average WTI		
		$75.00	**$88.00**	**$95.00**
2012 Average WI Production (bbls per day)	**2,400**	102%	90%	83%
	2,600	94%	82%	75%
	2,800	87%	75%	69%

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, ranging from $11.25 to $11.75 per barrel.
4. Capital budget of US $14 million in the Salt Flat Field.
5. Differential to WTI held constant at WTI less $5.00 per barrel, not including transportation.
6. Foreign exchange rate: $1.00 CDN = $1.00 USD.
7. Effects of hedging have been considered. See "Realized and unrealized risk management gain/loss" section of this MD&A.

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 $88 WTI per barrel, average working interest production guidance of 2,600 barrels of oil per day and other assumptions as listed in the section above, a weakening of the Canadian dollar by $0.02 relative to the US dollar results in a decrease in the payout ratio from 50% to 49% and a decrease in the sustainability ratio from 82% to 81%.

Growth by acquisitions

Eagle continues to actively pursue its stated strategy of acquiring additional producing properties in the United States. Eagle added to its business development team in August, 2011 and is well positioned to compete for accretive acquisitions in 2012. The capital budget excludes corporate and property acquisitions, which are evaluated separately on their own merits.

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 are not applicable since the Trust currently does not have any natural gas production or debt).

	Full year impact on ➔	**Funds flow from operations ($)**	**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	358,000	$ 0.02
Gas production	+1000 mcf/d	N/A	N/A
Oil production	+100 bbls/d	1,827,000	$ 0.10
Currency (2)	+CDN strengthen by $0.01	(246,000)	$ (0.01)
Interest Rate	+1% prime	N/A	N/A

Notes:

(1) Per unit figures are based on 17,927,602 weighted average basic units outstanding for the year ended December 31, 2011.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate equal to year to date average sales volumes of 1,376 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 December 31, 2011	**Year Ended December 31, 2011**	**Year Ended December 31, 2010**
Loss	**$** (1,426,402)	**$** (1,213,585)	**$** (3,213,531)
Add back (deduct) items not involving cash:			
Unit-based compensation	2,071,526	7,847,492	673,123
Debt conversion costs	-	-	1,620,425
Unrealized risk management loss	1,679,824	503,121	-
Depletion, amortization and accretion	4,837,559	12,609,548	581,554
Finance expense	36,971	106,166	50,353
Funds flow from operations	**$** 7,199,478	**$** 19,852,742	$ (288,076)
Add back (deduct) items not directly related to field operations:			
Realized foreign exchange gain	(99,217)	(439,195)	(992,642)
Finance expense (cash portion)	21,872	66,681	4,529
Unit-based compensation (cash portion)	-	-	992,000
Risk management (gain) loss-realized	9,290	(43,017)	-
Administrative expenses	1,782,126	5,727,972	1,374,830
Interest income	(15,130)	(15,130)	-
Field netback	**$ 8,898,419**	**$ 25,150,053**	$ 1,090,641

Conclusions regarding the design and effectiveness of disclosure controls and procedures

Disclosure controls and procedures are controls and procedures designed to provide reasonable assurance that information required to be disclosed in reports filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis and is accumulated and communicated to the Trust's management, including the Chief Executive Officer and the Chief Financial Officer as appropriate, to allow timely decisions regarding required disclosure. As at December 31, 2011, the Chief Executive Officer and the Chief Financial Officer evaluated the design and operation of the Trust's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the Trust's disclosure controls and procedures were effective as at December 31, 2011.

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

Internal controls are processes designed and implemented by Management to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements and other financial information for external purposes in accordance with IFRS. Based on an evaluation of the Trust's internal controls over financial reporting as at December 31, 2011, the Chief Executive Officer and the Chief Financial Officer concluded that the Trust's internal controls over financial reporting were effective.

No Change in internal controls over financial reporting during the period October 1, 2011 to December 31, 2011

During the period beginning on October 1, 2011 and ended on December 31, 2011, there was no change in the Trust's internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust's internal controls over financial reporting. It should be noted, that the Trust's control system, no matter how well designed, can provide only reasonable, but not absolute, assurance of detecting, preventing and deterring errors or fraud.

Note about forward-looking statements

Certain of the statements made and information contained in this MD&A are forward-looking statements and forward looking information (collectively referred to as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historic fact are forward-looking statements. The Trust cautions investors that important factors could cause the Trust's actual results to differ materially from those projected, or set out, in any forward-looking statements included in this MD&A.

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

- the Trust's subsidiary's 2012 capital budget and specific uses, including the Trust's 2012 drilling plans;
- the Trust's expectation regarding its 2012 working interest average production and 2012 operating costs;
- the Trust's expectation that its 2012 capital budget should be sufficient to fully offset production declines and grow 2012 average annual production by approximately 10% over the Trust's 2011 exit rate
- the Trust's expectation that its current inventory of locations will be sufficient to continue drilling on the Salt Flat Field for at least three more years;
- sustainability and payout ratios;
- sensitivities to production rates and commodity prices
- sustainability of production;
- amount of and sustainability of distributions on the Units;
- existing credit facilities and the availability of new credit facilities to fund acquisitions;
- cash available from the distribution reinvestment and premium drip programs;
- expectations regarding the marketing of volumes;
- expectations that per barrel administrative costs in the future will trend lower due to increased production in 2012;
- the taxability of the Trust and the status of the Trust as a mutual fund trust and not a SIFT trust;
- management's objective to maintain a debt to cash flow ratio below 1.5 times; and
- the Trust's expectations that its funds flow from operations and 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.

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

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

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

Additional risks and uncertainties affecting the Trust are contained in the Trust's December 31, 2011 AIF under the heading "Risk 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. Eagle's production rates, operating costs and 2012 capital budget, and the Trust's distributions are subject to change in light of ongoing results, prevailing economic circumstances, obtaining regulatory approvals, commodity prices and industry conditions and regulations. New factors emerge from time to time, and it is not possible for management to predict all of these factors or to assess, in advance, the impact of each such factor on the Trust's business, or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statement.

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

Management's Report to the Unitholders of Eagle Energy Trust

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

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

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

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

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

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

MARCH 22, 2012

(signed) Kelly A. Tomyn
Kelly A. Tomyn
Vice President, Finance and
Chief Financial Officer

MARCH 22, 2012

March 22, 2012

Independent Auditor's Report

To the Unitholders of
Eagle Energy Trust

We have audited the accompanying consolidated financial statements of Eagle Energy Trust and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2011 and December 31, 2010 and the consolidated income (loss) statement and statement of comprehensive income (loss), statement of changes in unitholders equity and statements of cash flows for the year ended December 31, 2011 and the period from inception at July 20, 2010 to December 31, 2010, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

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

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

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

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

PricewaterhouseCoopers LLP, Chartered Accountants
Suite 3100, 111 5th Avenue SW, Calgary,Alberta, Canada T2P 5L3
T: +1 403 509 7500, F:+1 403 781 1825, www.pwc.com/ca

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Eagle Energy Trust and its subsidiaries as at December 31, 2011 and December 31, 2010 and its financial performance and its cash flows for the year ended December 31, 2011 and the period from inception at July 20, 2010 to December 31, 2010 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants

EAGLE
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TRUST

Eagle Energy Trust

Consolidated Financial Statements
(in Canadian dollars)

For the Year Ended December 31, 2011 and period ended December 31, 2010

Eagle Energy Trust

Consolidated Balance Sheet

(in Canadian dollars)

	Note		December 31, 2011		December 31, 2010
ASSETS					
Current assets					
Cash	17	$	7,495,344	$	31,731,118
Trade and other receivables	18		5,585,104		1,310,838
Prepaid expenses	19		305,400		60,865
			13,385,848		**33,102,821**
Non-current assets					
Exploration and evaluation	20		119,300		-
Oil and gas properties	21		145,066,519		126,519,338
Property, plant and equipment	22		126,969		34,739
Other intangible assets	23		187,171		211,329
			145,499,959		**126,765,406**
Total Assets		**$**	**158,885,807**	**$**	**159,868,227**
LIABILITIES					
Current liabilities					
Trade and other payables	24		14,397,658		7,145,552
Distributions payable	25		1,656,471		1,916,432
Risk Management Liability	5		503,121		-
			16,557,250		**9,061,984**
Non-current liabilities					
Other long term liabilities	24		-		507,453
Provision for liabilities and other charges	27		502,431		217,380
			502,431		**724,833**
Total Liabilities		**$**	**17,059,681**	**$**	**9,786,817**
UNITHOLDERS' EQUITY					
Trust capital	28		168,175,277		159,577,493
Other reserves	11		(718,440)		(4,366,120)
Accumulated loss			(4,427,116)		(3,213,531)
Accumulated cash distributions	25		(21,203,595)		(1,916,432)
Total Unitholders' Equity			**141,826,126**		**150,081,410**
Total Liabilities and Unitholders' Equity		**$**	**158,885,807**	**$**	**159,868,227**

The notes are an integral part of these financial statements

See Note 32 "Commitments" and Note 33 "Subsequent events"

Eagle Energy Trust

Consolidated income (loss) statement and Statement of comprehensive income (loss)

(in Canadian dollars)

	Note	Year Ended December 31, 2011	July 20 to December 31, 2010
Revenue	8	$ 31,771,486	$ 1,366,494
Cost of sales	9	19,170,465	857,407
Gross profit		12,601,021	509,087
Administrative expenses		5,773,359	1,374,830
Unit based compensation	10	7,847,492	1,665,123
Operating loss		**(1,019,830)**	**(2,530,866)**
Debt conversion costs		-	(1,620,425)
Foreign exchange gain, net	11	439,195	992,642
Finance expense	12	(172,846)	(54,882)
Risk management loss	5	(460,104)	-
Loss before taxation		**(1,213,585)**	**(3,213,531)**
Income tax expense (recovery)	13	-	-
Loss for the period		**$ (1,213,585)**	**$ (3,213,531)**
Other comprehensive income (loss) for the period			
Foreign currency translation gain (loss)	11	3,647,680	(4,366,120)
Total comprehensive income (loss) for the period		**$ 2,434,095**	**$ (7,579,651)**
Income (loss) per unit during the period			
Basic	16	(0.07)	(0.81)
Diluted	16	(0.07)	(0.81)

The notes are an integral part of these financial statements

Eagle Energy Trust

Consolidated Statement of Changes in Unitholders' Equity

For the year ended December 31, 2011 and period ended December 31, 2010
(in Canadian dollars)

	Note	Number of Trust Units	Trust capital	Currency reserve	Accumulated loss	Accumulated Cash distributions	Deficit	**Total Unitholders' equity**
Issued on initial organization – July 20, 2010		**2**	**200**					**200**
Loss for the period					(3,213,531)		(3,213,531)	(3,213,531)
Foreign currency translation gain (loss)				(4,366,120)				(4,366,120)
Total comprehensive income (loss)				(4,366,120)	(3,213,531)		(3,213,531)	(7,579,651)
Issue of Trust capital		16,950,000	169,500,000					169,500,000
Trust unit issuance costs			(13,513,334)					(13,513,334)
Unit based payments		349,978	349,978					349,978
Repurchase of initial trust units		(2)	(200)					(200)
Conversion of notes		324,103	3,240,849					3,240,849
Unitholder distributions						(1,916,432)	(1,916,432)	(1,916,432)
		17,624,079	159,577,293	-	-	(1,916,432)	(1,916,432)	157,660,861
Balance at December 31, 2010		**17,624,081**	**159,577,493**	**(4,366,120)**	**(3,213,531)**	**(1,916,432)**	**(5,129,963)**	**150,081,410**
Loss for the period		-	-	-	(1,213,585)	-	(1,213,585)	(1,213,585)
Foreign currency translation gain	11	-	-	3,647,680	-	-	-	3,647,680
Total comprehensive income		-	-	3,647,680	(1,213,585)	-	(1,213,585)	2,434,095
Issuance of Trust capital	28	919,518	9,009,900	-	-	-	-	9,009,900
Trust unit issuance costs	28	-	(412,116)	-	-	-	-	(412,116)
Unitholder distributions	25	-	-	-	-	(19,287,163)	(19,287,163)	(19,287,163)
		919,518	8,597,784	-	-	(19,287,163)	(19,287,163)	(10,689,379)
Balance at December 31, 2011		**18,543,599**	**168,175,277**	**(718,440)**	**(4,427,116)**	**(21,203,595)**	**(25,630,711)**	**141,826,126**

The notes are an integral part of these financial statements

Eagle Energy Trust

Consolidated Cash Flow Statement

For the year ended December 31, 2011 and period ended December 31, 2010
(in Canadian dollars)

	Note		Year Ended December 31, 2011		July 20 to December 31, 2010
Cash flows from operating activities					
Net cash generated by operating activities	29	$	**14,312,104**	$	**5,370,155**
Cash flows from investing activities					
Additions to exploration and evaluation			(119,300)		-
Additions to oil and gas properties			(27,096,162)		(110,273,747)
Additions to property, plant and equipment			(133,679)		(35,196)
Net cash used in investing activities		$	**(27,349,141)**	$	**(110,308,943)**
Cash flows from financing activities					
Proceeds from issuance of units			8,961,200		149,375,319
Trust unit issue costs			(412,116)		(13,513,334)
Proceeds from borrowings			-		1,577,560
Cash distributions to unitholders			(19,547,124)		-
Repurchase of initial Trust organizational units			-		(200)
Deferred financing charges			(78,017)		(221,599)
Net cash (used in) generated by financing activities		$	**(11,076,057)**	$	**137,217,746**
Net (decrease) increase in cash and cash equivalents			**(24,113,094)**		**32,278,958**
Effects of exchange rates on cash and cash equivalents			(122,680)		(548,040)
Cash at beginning of the period			31,731,118		200
Cash at end of the period	17	$	**7,495,344**	$	**31,731,118**

The notes are an integral part of these financial statements

Eagle Energy Trust

Notes to Consolidated Financial Statements

For the year ended December 31, 2011 and period ended December 31, 2010
(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 consolidated financial statements, Eagle Energy Trust and its subsidiaries are referred to collectively as the "Trust" or "Eagle" for purposes of convenience. For a list of subsidiaries and a detailed description of the structure of the Trust, refer to "Subsidiaries and consolidated entities" note 6.

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 Salt Flat Field acquisition (see "Acquisitions" note 7).

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

2.1 Basis of preparation

Basis of accounting

The consolidated financial statements were authorized for issue in accordance with a resolution of the Board of Directors made on March 22, 2012.

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

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

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

Basis of consolidation

The consolidated financial statements incorporate the financial statements of the Trust and entities controlled by the Trust (including its subsidiaries) up to the balance sheet date. Subsidiaries are all entities over which the Trust has the power to govern the financial and operating policies generally accompanying a security holding of more than one half of the voting rights. The existence and effect of potential voting rights that are currently exercisable or convertible are considered when assessing whether the Trust controls another entity. All subsidiaries of the Trust are directly or indirectly wholly-owned by the Trust.

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

The activities of subsidiaries are included in the consolidated financial statements from the effective date that control commences until the date that control ceases. Intercompany balances and transactions and any unrealized income and expenses arising from intercompany transactions are eliminated in preparing the consolidated financial statements.

2.2 Adoption of new and revised standards

Accounting standards and interpretations issued but not yet adopted

At the date of authorization of these financial statements, the following standards and interpretations, which have not been applied in these financial statements, were issued by the IASB but not yet in effect. The Trust will be required to adopt these new pronouncements, subject to the comments below regarding IFRS 9, as of January 1, 2013.

- IFRS 9, “Financial Instruments”, is the first phase of the IASB’s project to replace IAS 39, “Financial Instruments: Recognition and Measurement”. IFRS 9 replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The impairment and hedge accounting principles to be included in IFRS 9 have not yet been issued by the IASB. IFRS 9 is effective for annual periods beginning on or after January 1, 2015 with different transitional arrangements depending on the date of initial application.

- IFRS 10, “Consolidated Financial Statements”, is the result of the IASB’s project to replace Standing Interpretations Committee 12, “Consolidation – Special Purpose Entities” and the consolidation requirements of IAS 27, “Consolidated and Separate Financial Statements”. The new standard eliminates the current risk and rewards approach and establishes control as the single basis for determining the consolidation of an entity.

- IFRS 7, “Financial Instruments: Disclosures”, which requires disclosure of both gross and net information about financial instruments eligible for offset balance sheet and financial instruments subject to master netting arrangements. Concurrent with the amendments to IFRS 7, the IASB also amended IAS 32, “Financial Instruments: Presentation” to clarify the existing requirements for offsetting financial instruments in the balance sheet. The amendments to IAS 32 are effective as of January 1, 2014.

- IFRS 11, “Joint Arrangements”, which is the result of the IASB’s project to replace IAS 31, “Interest in Joint Ventures”. The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted. Under IAS 31, joint ventures could be proportionately accounted.

- IFRS 12, “Disclosures of Interests in Other Entities”, outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users in evaluating the nature, risks and financial effects associated with an entity’s interests in subsidiaries and joint arrangements.

- IFRS 13, “Fair Value Measurement”, provides a common definition of fair value, establishes a framework for measuring fair value under IFRS and enhances the disclosures required for fair value measurements. The standard applies where fair value measurements are required and does not require new fair value measurements.

Although it is anticipated that the adoption of the above standards and interpretations should not have a material impact on its Consolidated Financial Statements, the Trust is assessing the exact impact. The exact impact will depend on the individual transaction concerned, with potentially different amounts being recognized in the consolidated financial statements than would have previously been the case.

2.3 Significant accounting policies

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

Business combinations

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

Jointly controlled operations and jointly controlled assets

Many of the Trust's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Trust's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

Foreign Currency

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

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

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

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

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

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

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

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

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

Financial instruments

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

A. Non-derivative financial instruments

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

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

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

(a) Financial assets

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

(i) Loans and receivables

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

Cash and cash equivalents comprise cash on hand and current balances and deposits with banks or similar institutions which are readily convertible to cash and which are subject to insignificant risk of changes in value.

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

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

(ii) Impairment of financial assets

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

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

(b) Financial liabilities and equity

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

(i) Trade payables and distributions payable

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

(ii) Borrowings

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

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

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

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

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

(iii) Equity instruments

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

(iv) Compound instruments

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

B. Derivative financial instruments

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

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

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

Non-current assets held for sale

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

Exploration and evaluation expenditures

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

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

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

Oil and gas properties

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

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

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

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

Impairment - Exploration and evaluation expenditures

Exploration and evaluation assets are assessed for impairment if:

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

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

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

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

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

Impairment – Oil and gas properties

Oil and gas properties (which are further classified as developed oil and gas assets and production facilities and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Oil and gas properties are grouped into CGU’s for impairment testing. At this time, the Trust has grouped its oil and gas properties into one CGU, the Salt Flat Field. An impairment loss is recognized for the amount by which the asset’s or CGU’s carrying amount exceeds its recoverable amount. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

Decommissioning provision

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

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

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

Property, plant and equipment

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

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

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

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

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

Revenue recognition

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

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

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

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

Unit-based compensation

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

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

Finance income and expense

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

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

Unitholder distributions

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

Taxation

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

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

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

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

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

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

Trust unit calculations

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

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

3. Critical accounting estimates and judgments

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

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

Estimation of oil and gas reserves

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

Capitalized exploration and evaluation expenditures

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

Decommissioning provision

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

Impairment indicators

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

Income taxes

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

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

Derivative financial instruments

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

Classification of Trust units as equity

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

Contingencies

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

Unit Based Compensation

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

4. Determination of fair values

A review of the financial statements has concluded that there are no significant differences between the book values and fair values of the financial assets and liabilities of the Trust as at December 31, 2011 and December 31, 2010.

5. Financial risk management

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

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

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

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

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

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

Credit risk

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

	December 31, 2011	December 31, 2010
Cash	$ 7,495,344	$ 31,731,118
Trade and other receivables	5,585,104	$ 1,310,838
	$ 13,080,448	**$** 33,041,956

Cash

The Trust limits its exposure to credit risk by investing only in liquid securities and only with counterparties with a strong credit rating. Given this approach, Management does not expect any counterparty to fail to meet its obligations and did not have any such investments at December 31, 2011 and December 31, 2010.

Trade and other receivables

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

Receivables from the Trust's product 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. The Trust historically has not experienced collection issues with its marketer. The Trust does not typically obtain collateral from its marketers.

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

The Trust does not anticipate any default as it transacts with creditworthy customers and Management does not expect any losses from non-performance by these customers. As such, no provision for doubtful accounts has been recorded at December 31, 2011 and December 31, 2010.

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

	December 31, 2011	December 31, 2010
Oil and natural gas marketing companies	$ 4,487,541	$ 1,303,979
Receivable from Salt Flat joint venture working interest owner	1,029,886	-
Other	67,677	$ 6,859
	$ 5,585,104	**$** 1,310,838

The Trust's most significant customer, a US oil and natural gas marketer, accounted for approximately 80% or $4,487,541 of trade receivables at December 31, 2011 and approximately 100% or $1,303,979 at December 31,

2010. Additionally, 18% or $1,029,886 represents billed and accrued receivables from the joint venture working interest owner. As of December 31, 2011 and December 31, 2010 the receivables were considered current (less than 90 days old) and none were contractually past due.

Liquidity risk

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

At December 31, 2011, the Trust had a working capital deficiency of approximately $3.2 million. In addition, the Trust had a $US 16.5 million credit facility of which $US 16.5 million was available at December 31, 2011 (refer to "Borrowings" note 26). To better manage its liquidity risk, the Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures ("AFEs") on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil and natural gas revenue each month.

The following are the contractual undiscounted maturities of financial liabilities, including estimated interest payments, as applicable, at December 31, 2011:

	Carrying amount	Contractual cash flows	Less than one year	One – two years	Two – five years	More than five years
Trade and other payables	$ 14,397,658	$ 5,925,743	$ 5,925,743	$ -	-	-
Distributions payable	1,656,471	1,656,471	1,656,471	-	-	-
Risk Management Liability	503,121	503,121	503,121			
	$ 16,557,250	$ 8,085,335	$ 8,085,335	$ -	-	-

Contractual cash flows at December 31, 2011 exclude the current portion of unit-based compensation of $8,471,915; see note 24.

The following are the contractual undiscounted maturities of financial liabilities, including estimated interest payments, as applicable, at December 31, 2010:

	Carrying amount	Contractual cash flows	Less than one year	One – two years	Two – five years	More than five years
Trade and other payables	$ 7,145,552	$ 6,979,883	$ 6,979,883	$ -	-	-
Distributions payable	1,916,432	1,916,432	1,916,432	-	-	-
	$ 9,061,984	$ 8,896,315	$ 8,896,315	$ -	-	-

Contractual cash flows at December 31, 2010 exclude the current portion of unit-based compensation of $165,670; see note 24.

Risk management liability

The Trust enters into certain risk management contracts periodically to economically hedge a portion of its oil and natural gas sales. The counterparty to these instruments is a highly rated Canadian corporate, investment banking, and capital markets group. See "Market risk", "Commodity price risk" for further discussion regarding these risk management contracts.

The Trust units contain a redemption feature, see "Trust capital" note 28. Utilizing the terms of redemption as outlined in note 28, the total market redemption price for all outstanding units at December 31, 2011 would be $164,581,547 ($9.66 per unit 10 day volume weighted average price x 90% x 18,931,099 units). As the maximum cash outlay required by the Trust is capped at $100,000 per month or $1,200,000 per year, the Trust would have approximately 137 years to pay out this commitment.

Market risk

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

The Trust may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand.

The Trust enters into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Trust does not apply hedge accounting for these contracts. The Trust's production is 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 December 31, 2011 the Trust has entered into the following financial contracts to mitigate the effects of fluctuating prices on a portion of its production as follows:

1. A costless collar contract for 200 bbls of oil per day with a February 2011 through January 2012 term at a floor of $US 85.00 per barrel and a ceiling of $US 100.00 per barrel.
2. A costless collar contract for 200 bbls of oil per day with a May 2011 through April 2012 term at a floor of $US 88.00 per barrel and a ceiling of $US 107.55 per barrel.
3. A fixed contract to sell 100 bbls of oil per day with a May 2011 through April 2012 term at a price of $US 101.00 per barrel.
4. 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.
5. 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.

Subsequent to December 31, 2011, the Trust entered into an additional financial contract. See Note 33.

Summary of Unrealized Risk Management Positions as at December 31, 2011 ($nil at December 31, 2010)

	Volume	*Measure*	*Beginning*	*Term*	*Floor $US*	*Ceiling $US*	*Fair Value $CA*
Oil Fixed Price							
NYMEX (i)	200	bbls/d	Feb-11	Jan-12	85.00	100.00	$ (11,013)
NYMEX (i)	200	bbls/d	May-11	Apr-12	88.00	107.55	(9,225)
NYMEX (ii)	100	bbls/d	May-11	Apr-12	101.00	101.00	29,364
NYMEX (ii)	200	bbls/d	Nov-11	Oct-12	91.00	91.00	(527,883)
NYMEX (i)	500	bbls/d	Jan-12	Dec-12	92.00	105.00	15,636
							$ (503,121)

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

Net Risk Management Position as at December 31, 2011 ($nil at December 31, 2010)

Current Liability	$ (503,121)
Net Risk Management Liability	**$** (503,121)

The total net fair value of Eagle's unrealized risk management positions at December 31, 2011 is a liability of $503,121 and has been calculated using both quoted prices in active markets and observable market-corroborated data.

Reconciliation of Unrealized Risk Management Positions
For the Year Ended December 31, 2011

	Fair Value		Total Unrealized Gain (Loss)	
Fair value of contracts, beginning of year	$	-	$	
Fair value of contracts realized during the period		43,017		43,017
Change in fair value of contracts in place at the beginning of year and contracts entered into during period		(546,138)		(546,138)
Fair value of contracts as at December 31, 2011	**$**	(503,121)	**$**	(503,121)

Earnings Impact of Realized and Unrealized Gain (Loss)
For the Year Ended December 31, 2011 (year ended December 31, 2010 - $nil)

	Realized Gain (Loss)		Unrealized Gain (Loss)		Total Net Gain (Loss)	
Net effect - risk management	**$**	43,017	**$**	(503,121)	**$**	(460,104)

A 10% increase (decrease) in the market price of oil from its 2011 year average of $US 95.00 WTI would have increased (decreased) income by approximately $3,400,000. This analysis assumes that all other variables remain constant.

Foreign exchange risk

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

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

As at December 31, 2011	$US		$CA	
Cash	$	6,103,948	$	6,207,715
Trade and other receivables		5,425,198		5,517,427
Trade and other payables		(5,246,669)		(5,335,862)
	$	**6,282,477**	**$**	**6,389,280**

The average exchange rate during the year ended December 31, 2011 was $US 1 equal to $CA 0.9893, and the exchange rate at December 31, 2011 was $US 1 equal to $CA 1.017.

A 10% strengthening (weakening) of the Canadian dollar against the US dollar from its 2011 year average of $CA 0.9893 ($US 1.0108) would have decreased (increased) income by approximately $1,245,000. This analysis assumes that all other variables remain constant.

As at December 31, 2010	$US		$CA	
Cash	$	339,853	$	338,018
Trade and other receivables		1,313,954		1,306,859
Trade and other payables		(5,134,489)		(5,106,763)
	$	**(3,480,682)**	**$**	(3,461,886)

The average exchange rate during the period ending December 31, 2010 was $US 1 equal to $CA 1.0077, and the exchange rate at December 31, 2010 was $US 1 equal to $CA 0.9946.

A 10% strengthening (weakening) in the Canadian dollar against the US dollar at December 31, 2010 would have decreased (increased) income by approximately $321,000. This analysis assumes that all other variables remain constant.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. There were no draws against the credit facility during the year ended December 31, 2011 and no amounts outstanding as of December 31, 2011 and December 31, 2010. Therefore, the Trust had no interest rate risk, and as a result, the Trust did not hedge against any interest rate exposure.

Capital management

The Trust's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Trust manages its capital structure and makes adjustments to it based upon economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include working capital, loans and borrowing, and unitholders' equity. In order to maintain or adjust the capital structure, the Trust may issue units, engage in external debt financing, and adjust its capital spending to manage current and projected debt levels.

The Trust monitors capital based on the ratio of external debt to cash generated from operations. This ratio is calculated as external debt, defined as outstanding loans and borrowings, divided by annualized cash generated from operations before changes in non-cash working capital. Management's objective is to maintain an external debt to estimated future annual cash flows not to exceed 1.5 to 1.0. This ratio may increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Trust prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at December 31, 2011 and December 31, 2010, the Trust's ratio of external debt to annualized cash flow was 0.0 to 1.0, within the range established by the Trust, and due to there being no outstanding debt.

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

Any draws against the existing credit facility would be subject to established covenants. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves. See "Borrowings" note 26.

6. Subsidiaries and consolidated entities

The following table summarizes the structure of the Trust following completion of the initial public offering and the indirect investment by the Trust in the Partnership (Eagle Energy Acquisitions LP). All subsidiaries of the Trust are directly or indirectly wholly-owned by the Trust.

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

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

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

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

The results of the above subsidiaries, together with Eagle Energy Inc. (as further described below) have been included in the consolidated financial statements. All of the entities have calendar year ends.

Eagle Energy Inc. is the Administrator of the Trust and was formed under the laws of the Province of Alberta on March 28, 2008. The sole shareholder of Eagle Energy Inc. is EEI Holdings Inc. and the sole shareholder of EEI

Holdings Inc. is Richard Clark, Chief Executive Officer of the Administrator. Eagle Energy Inc. is not a legal subsidiary of the Trust.

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

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

Eagle Energy Inc. meets the accounting definition of a special purpose entity and accordingly Eagle Energy Inc. has been consolidated based on the principles set out in *SIC 12 Consolidation – Special Purpose Entities.*

7. Acquisitions

On November 24, 2010, Eagle acquired an average 73% working interest in the Salt Flat Field (a light oil producing property located in south central Texas) from OAG Holdings LLC for total consideration, including closing adjustments, of $127.1 million. The acquisition had an effective date of June 1, 2010 and a closing date of November 24, 2010.

Consideration comprised cash and 2,000,000 Trust units of Eagle valued at $10.00 per Trust unit, being the initial public offering price of the units on the closing date of the acquisition. 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	$	127,279,122
Decommissioning liabilities		(139,761)
	$	127,139,361

The consideration paid or payable is as follows:		
Cash at closing	$	105,316,897
Trust units issued at closing		20,000,000
Owing to vendor at year end for final adjustments		1,822,464
	$	127,139,361

Had this transaction closed on July 20, 2010, the formation date of the Trust, the additional revenue, net of royalties, would have been approximately $US 3,439,000 for the period ended December 31, 2010. The net income effect is not determinable.

8. Operating segments

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

Geographical information

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

Revenue

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

		Year Ended December 31, 2011		Year Ended December 31, 2010
Revenue before royalties	$	44,180,632	$	1,883,589
Interest Income		15,130		-
Royalties		(12,424,276)		(517,095)
	$	31,771,486	**$**	1,366,494

Non-Current assets

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

9. Cost of sales

		Year Ended December 31, 2011		Year Ended December 31, 2010
Operating costs related to the field	$	6,606,303	$	275,853
Depreciation, depletion and amortization		12,564,162		581,554
	$	19,170,465	**$**	857,407

10. Unit-based payments

The following table reconciles unit-based compensation expense.

		Year Ended December 31, 2011		Year Ended December 31, 2010	
Cash paid on performance option surrender	$	-	$	992,000	Note 10 (a)
Units issued on performance option surrender		1,924,916		205,905	Note 10 (a)
Restricted unit rights		2,206,918		163,489	Note 10 (b)
Unit options		3,498,038		303,729	Note 10 (c)
Phantom unit rights		217,620		-	Note 10 (d)
Total unit-based compensation expense	**$**	7,847,492	**$**	1,665,123	

Grant, surrender and replacement of performance options

On September 14, 2010, 775,000 performance options were granted as compensation to persons who provided substantial services and expertise in the creation of the Trust and sourcing the acquisition of the Salt Flat Interest. After determining that the performance options would not meet imposed regulatory requirements, the Trust entered into performance option exchange and escrow agreements with holders of the 775,000 performance options that saw holders surrender their performance options, concurrent with the November 24, 2010 closing of the Trust's initial public offering, in exchange for:

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

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

Note (a)

Cash and units issued upon surrender of performance options

On November 24, 2010, the Trust paid $992,000 in cash and issued 387,500 units upon surrender of the performance options. This equated to one-half of a unit and $1.28 cash for each performance option surrendered.

The Trust withheld the cash to pay taxation agencies the tax that would result from the holders disposing of their performance options. The fair value estimate associated with the cash component, $992,000, was immediately expensed in the income statement. At December 31, 2010, $96,000 is included in trade and other payables related to remaining amounts estimated to be payable to taxation agencies. At December 31, 2011, all amounts have been paid and no amount remains payable to taxation agencies.

The 387,500 units were escrowed, with escrow releases as to two-thirds on September 14, 2012 and the remaining one-third on September 14, 2013. The fair value estimate associated with the escrowed units is expensed in the income statement over the escrow period with the offsetting entry to either trade and other payables or other long-term liabilities. At December 31, 2011, $2,130,821 (December 31, 2010 - $nil) was included in trade and other payables and $nil (December 31, 2010 - $205,905) was included in other long-term liabilities relating to these units. Upon release from escrow, the related accumulated liability will be transferred to the trust capital account in unitholders' equity. At December 31, 2011, the fair value of the 387,500 units was recalculated. The Trust is required to recalculate the fair value of the liability related to these escrowed units at the end of each reporting period. The following schedule shows the continuity of escrowed units issued upon surrender of performance options:

	Year Ended December 31, 2011
Balance, beginning of period	387,500
Issued	0
Balance, end of period	387,500
Number of units in escrow	387,500

The fair value of the escrowed units was assumed to be equal to the December 31, 2011 closing unit price of $10.05 per unit (December 31, 2010 - $10.44 per unit). A forfeiture rate of 5% was used and, due to the limited history of the Trust, this figure is an estimated expected rate.

Note (b)

Cash settled RURs issued upon surrender of performance options

The Trust issued 775,000 RURs, which equated to one RUR for each performance option surrendered. Each RUR entitles the holder to receive cash payments equal to the distributions payable on one unit as well as capital appreciation of units. RURs vest as to two-thirds on September 14, 2012 and the remaining one-third on September 14, 2013. Until vested, RUR payments will be accrued for the benefit of the holders. Holders of the RURs are entitled to receive a cash payment equal to accrued distributions and capital appreciation, once the RURs vest.

The fair value estimate associated with the RURs is expensed in the income statement over the vesting period with the offsetting entry to either trade and other payables or other long-term liabilities. At December 31, 2011, $2,370,407 (December 31, 2010 - $nil) was included in trade and other payables and $nil (December 31, 2010 – $163,489) was included in other long term liabilities relating to these RURs. At December 31, 2011, the fair value of the 775,000 RURs was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period.

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

	Year Ended December 31, 2011	**Period Ended December 31, 2010**
Balance, beginning of period	775,000	0
Issued	0	775,000
Balance, end of period	775,000	775,000
Number of restricted unit rights vested	Nil	Nil

The Black-Scholes valuation model is used to determine the fair value of the RURs issued by the Trust. Given the limited trading history of the Trust, which commenced trading on November 24, 2010, a representative sample of peer group entities was used in order to determine expected unit price volatility. The fair value of the RURs was estimated using the following inputs:

	December 31, 2011	December 31, 2010
Fair value at the balance sheet date	$ 5.59	$ 3.97
Volatility	35%	25%
Life of restricted unit rights	9.0 years	10 years
Risk-free interest rate	1.98%	2.85%

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

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

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

The fair value estimate associated with the options is expensed in the income statement over the vesting period with the offsetting entry to either trade and other payables or other long-term liabilities. At December 31, 2011, $3,801,767 (December 31, 2010 - $165,670) was included in trade and other payables and $nil (December 31, 2010 - $138,059) was included in other long-term liabilities relating to this option plan. At December 31, 2011, the fair value of the options was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period.

The closing trading price of the Trust's units at December 31, 2011 was $10.05 per unit (December 31, 2010 - $10.44 per unit).

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

	Year Ended December 31, 2011		Period Ended December 31, 2010	
	Number of options	Weighted average exercise price	Number of Options	Weighted average exercise price
Outstanding, beginning of period	1,300,000	$ 8.93	-	-
Forfeited	(20,000)	9.03	-	-
Exercised	(10,000)	9.03	-	-
Granted	436,000	8.72	1,300,000	10.00
Outstanding at end of period	1,706,000	$ 8.88	1,300,000	10.00
Exercisable at end of period	423,333	$ 8.93	-	-

During the year, 10,000 options to purchase units were exercised, resulting in a reclassification from trade and other payables (unit based compensation) to trust capital of $48,700.

The range of exercise prices of the outstanding options is as follows:

	Weighted average exercise price	Weighted average contractual life (years)
$8.47- $10.04	$ 8.88	9.1

The fair value of the options was estimated using the Black-Scholes model with the following weighted average inputs. Given the limited trading history of the Trust, which commenced trading on November 24, 2010, a representative sample of peer group entities was used in order to determine expected unit price volatility:

	December 31, 2011	December 31, 2010
Fair value at the balance sheet date	$ 4.73	$ 3.97
Unit price	$ 10.05	$ 10.00
Exercise price	$ 8.88	$ 10.00
Volatility	35%	25%
Option life	9.1 years	10 years
Distributions – none estimated, due to declining strike price feature	0%	0%
Risk-free interest rate	1.98%	2.85%

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 plan

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

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

The PURs have a 10 year term and vest as to one-third on each of the first, second and third anniversaries of the date of grant. PURs granted are not subject to any performance criteria apart from continued service or employment. PURs are forfeited if the holder leaves before vesting. Until vested, PUR payments will be accrued for the benefit of the holders. Holders of the PURs are entitled to receive cash payments on a calendar year basis once the PURs vest. A present value factor is applied to the amount otherwise payable to the holder of the PURs to account for the fact that PUR holders receive their payments earlier than a regular option holder who holds their option to the full term otherwise would.

The fair value estimate associated with the PURs is expensed in the income statement over the vesting period with the offsetting entry to either trade and other payables or other long-term liabilities. At December 31, 2011, $217,620 (December 31, 2010 - $nil) was included in trade and other payables and $nil (December 31, 2010 - $nil) was included in other long-term liabilities relating to the PUR plan. At December 31, 2011, the fair value of the PURs was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period.

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

	Year Ended December 31, 2011
Balance, beginning of period	0
Issued	185,000
Balance, end of period	185,000
Number of phantom unit rights vested	Nil

The Black-Scholes valuation model is used to determine the fair value of the PURs issued by the Trust. Given the limited trading history of the Trust, which commenced trading on November 24, 2010, a representative sample of peer group entities was used in order to determine expected unit price volatility. The fair value of the PURs was estimated using the following weighted average inputs:

	December 31, 2011
Fair value at the balance sheet date	$ 4.76
Volatility	35%
Life of restricted unit rights	9.5 years
Risk-free interest rate	1.98%

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

11. Foreign exchange

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

	Year Ended December 31, 2011	Year Ended December 31, 2010
Net gain arising on settlement of foreign currency transactions arising out of operating activities	$ 439,195	$ 992,642

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

	Year Ended December 31, 2011
At December 31, 2010	$ (4,366,120)
Foreign currency translation gain	3,647,680
At December 31, 2011	$ (718,440)

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

12. Finance expense

		Year Ended December 31, 2011		Year Ended December 31, 2010
Amortized application fees on revolving line of credit	$	94,492	$	7,488
Standby and bank fees		66,680		4,529
Interest on convertible promissory notes – note 30		-		42,865
Accretion of decommissioning provision		11,674		-
Net finance expense recognized	$	172,846	$	54,882

13. Taxation

Reconciliation of effective tax rate

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

			Year Ended December 31, 2011			Year Ended December 31, 2010
Loss before taxation		$	(1,213,585)		$	(3,213,531)
Expected tax rate			35%			35%
Expected income tax recovery			(424,755)			(1,124,736)
Decrease (Increase) resulting from:						
Non-deductible items – permanent differences						
Administrative expenses of the Trust	35%		830,244	35%		163,494
Unit-based compensation	35%		2,746,622	35%		582,793
Foreign exchange gain, net	35%		(153,718)	35%		(347,425)
Debt conversion costs	35%		-	35%		567,149
Risk management loss	35%		161,036	35%		-
Changes in temporary differences for which no amounts are recognized	35%		539,041	35%		480,000
Items deductible at the subsidiary level						
Interest on internal debt of subsidiary	35%		(3,728,921)	35%		(340,200)
Other	35%		30,451	35%		18,925
Total income tax expense (recovery)	35%	$	-	35%	$	-

Deferred tax assets and liabilities:

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

December 31,	2011	2010
Deferred tax liabilities:		
Oil and gas properties in excess of tax value	$13,118,067	$ 1,157,825
Exploration and evaluation assets	-	-
	13,118,067	1,157,825
Less deferred tax assets:		
Non-capital losses – US based	(14,137,752)	(1,637,825)
Net deferred tax liability (asset) – before valuation allowance	(1,019,685)	(480,000)
Valuation allowance	1,019,685	480,000
Net deferred tax liability (asset)	$ -	$ -

Movement in temporary differences during the year:

For the year ended December 31,	Income (Loss) Statement 2011	Income (Loss) Statement 2010	Balance Sheet 2011	Balance Sheet 2010
Oil and gas properties	$ 11,960,242	$ 1,157,825	$ 13,118,067	$ 1,157,825
Non-capital tax losses - U.S. based	(12,499,927)	(1,637,825)	(14,137,752)	(1,637,825)
	$ (539,685)	$ (480,000)	$ (1,019,685)	$ (480,000)

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

14. Depreciation, depletion and amortization

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

	Year ended December 31, 2011		
	Oil and gas properties	Property, plant and equipment	Total
Cost of sales	$ 12,564,161	$ -	$ 12,564,161
Administrative expenses	-	45,387	45,387
	$ 12,564,161	**$** 45,387	**$** 12,609,549

	Year ended December 31, 2010		
	Oil and gas properties	Property, plant and equipment	Total
Cost of sales	$ 581,554	$ -	$ 581,554
Administrative expenses	-	-	-
	$ 581,554	**$** -	**$** 581,554

15. Employees and key management

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

	Year ended December 31, 2011	**Year ended December 31, 2010**
Salaries and wages	$ 2,222,443	$ 208,038
Benefits and other personnel	99,468	-
Unit-based payments (i)	5,162,168	932,744
Total employee and executive remuneration	$ 7,484,079	$ 1,140,782

(i) Represents the amortization of unit based compensation as recorded in the financial statements. See Note 10.

Key management personnel is comprised of the Chief Executive Officer (CEO), the Chief Operating Officer (COO), the Chief Financial Officer (CFO) and the Directors. The aggregate remuneration of key management personnel was as follows:

	Year ended December 31, 2011	Year ended December 31, 2010
Directors fees	$ 198,000	$ -
Salaries and wages	822,786	200,221
Benefits and other personal costs	29,670	-
Unit-based payments (i)	7,034,525	918,726
Total executive remuneration	$ 8,084,981	$ 1,118,947

(i) Represents the amortization of unit based compensation as recorded in the financial statements. See Note 10.

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

16. Loss per unit

	Year Ended December 31, 2011	Year Ended December 31, 2010
Loss attributable to unitholders	$ (1,213,585)	$ (3,213,531)
Weighted average number of units outstanding (basic and diluted)	17,927,602	3,971,578
Basic and diluted income (loss) per unit	**$ (0.07)**	**$ (0.81)**

Calculation

Basic income per unit is calculated by dividing the income attributable to owners of the Trust by the weighted average number of units outstanding during the period. Diluted income per unit is calculated using the income for the period divided by the weighted average number of units outstanding assuming the conversion of potentially dilutive equity instruments outstanding.

Per unit amounts

Diluted income per unit is equal to basic income per unit as it was determined that the conversion of potentially dilutive equity instruments would be anti-dilutive. Excluded from the year-ended, December 31, 2011 number of units outstanding is the effect of the 387,500 units issued to certain directors, Management and a consultant on the surrender of previously granted performance options as well as 1,706,000 options as their effect is anti-dilutive. Refer to "Trust capital" note 28.

17. Cash

	December 31, 2011	December 31, 2010
Cash in banks	**$** 7,495,344	**$** 31,731,118

As of December 31, 2010 and December 31, 2011, there are no compensating balance arrangements that place restrictions on the use of available cash.

18. Trade and other receivables

	December 31, 2011	December 31, 2010
Trade receivables	$ 5,517,427	$ 1,303,979
Other	48,834	6,308
GST	18,843	551
	$ 5,585,104	**$** 1,310,838

Trade receivables that are less than three months past due are not considered impaired. As of December 31, 2010 and December 31, 2011 there were no past due receivables and thus no balances against which a doubtful allowance has been provided.

19. Prepaid expenses

	December 31, 2011	December 31, 2010
Insurance	$ 130,970	$ 60,865
Rent	68,025	-
Deposits	70,765	-
Software Licenses	35,640	-
	$ 305,400	**$** 60,865

The balances are not deemed impaired due to their current status.

20. Exploration and evaluation assets

At December 31, 2010	$ -
Additions	119,300
Transfers to oil and gas properties	-
At December 31, 2011	**$** 119,300

As most of the activity in the Salt Flat field is focused on developing the existing proved and probable reserves, exploration and evaluation expenditures are limited.

21. Oil and gas properties

	Developed oil & gas assets	Production facilities and equipment	Capitalized future decom-missioning costs	Total
Cost				
Additions	$ 126,566,973	$ 316,539	$ 217,380	$ 127,100,892
At December 31, 2010	$ 126,566,973	$ 316,539	$ 217,380	$ 127,100,892
Accumulated depreciation				
Charge for the period	$ (573,893)	$ (7,661)	$ -	$ (581,554)
At December 31, 2010	$ (573,893)	$ (7,661)	$ -	$ (581,554)
Net book value				
At December 31, 2010	$ 125,993,080	$ 308,878	$ 217,380	$ 126,519,338

	Developed oil & gas assets	Production facilities and equipment	Capitalized future decom-missioning costs	Total
Cost				
At December 31, 2010	$ 126,566,973	$ 316,539	$ 217,380	$ 127,100,892
Additions	27,798,429	3,039,537	273,376	31,111,342
Transfers from exploration and evaluation	-	-	-	-
At December 31, 2011	$ 154,365,402	$ 3,356,076	$ 490,756	$ 158,212,234
Accumulated depreciation				
At December 31, 2010	$ (573,893)	$ (7,661)	$ -	$ (581,554)
Charge for the period	(11,981,479)	(582,683)	-	(12,564,161)
At December 31, 2011	$ (12,555,372)	$ (590,344)	$ -	$ (13,145,715)
Net book value				
At December 31, 2010	$ 125,993,080	$ 308,878	$ 217,380	$ 126,519,338
Net change	15,816,950	2,456,854	273,376	18,547,180
At December 31, 2011	$ 141,810,030	$ 2,765,732	$ 490,756	$ 145,066,519

Included in developed oil & gas asset balance at December 31, 2011 and December 31, 2010 is $123,789,875 of acquisition costs (comprised of the initial cost, see “Acquisitions” note 7, of $127,139,361 reduced by a December 31, 2010 translation adjustment of $3,349,486) associated with the Salt Flat Field acquisition. The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $54,982,000 (December 31, 2010 - $54,241,000) were included in the depletion calculation.

22. Property, plant and equipment

	Furniture, fixtures, and equipment	Computer equipment	Total
Cost			
At December 31, 2010	$ -	$ 34,739	$ 34,739
Additions	11,091	126,526	137,617
At December 31, 2011	$ 11,091	$ 161,265	$ 172,356
Accumulated Depreciation			
At December 31, 2010	$ -	$ -	$ -
Charge for the period	(1,210)	(44,177)	(45,387)
At December 31, 2011	$ (1,210)	$ (44,177)	$ (45,387)
Net book value			
At December 31, 2010	$ -	$ 34,739	$ 34,739
Net change	9,881	82,349	92,230
At December 31, 2011	$ 9,881	$ 117,088	**$ 126,969**

The additions for 2011 consist predominantly of computer hardware used in the general and administrative environment.

23. Other intangible assets

	December 31, 2011	December 31, 2010
Deferred financing charges	$ 289,151	$ 218,817
Accumulated amortization	(101,980)	(7,488)
Net other intangible assets	**$ 187,171**	$ 211,329

Deferred financing charges represent the upfront fees and related costs to establish and update the credit facility, see "Financial risk management" note 5 regarding liquidity and "Borrowings" note 26. The term of the facility per the signed term letter and credit facility agreement is November 24, 2013, which is three years from the closing date. Although no amount was drawn and outstanding on the facility at December 31, 2011 or December 31, 2010, the Trust does intend to utilize the facility especially with regard to liquidity risk management. Therefore, the charges are being amortized over the initial three year life of the credit facility on a straight-line basis. Once amounts are drawn on the facility the charges will be amortized using the effective interest method.

24. Trade and other payables

	December 31, 2011	December 31, 2010
Trade payables	$ 5,925,743	$ 6,423,951
Unit-based compensation	8,471,915	673,123
Trust issue costs	-	459,931
Employment related taxes	-	96,000
Less long-term portion of unit-based compensation	-	(507,453)
	$ 14,397,658	$ 7,145,552

Unit-based compensation liability includes both a current and long-term portion. The long-term portions of $nil and $507,453 for December 31, 2011 and December 31, 2010 respectively are reflected in the balance sheet category "Other long term liabilities". Refer to "Unit-based payments" note 10.

25. Distributions payable

	December 31, 2011	December 31, 2010	Cumulative
Beginning balance	$ 1,916,432	$ -	$ -
Distributions declared	19,287,163	1,916,432	21,203,595
Less distributions paid	(19,547,124)	-	(19,547,124)
Outstanding distributions declared and payable	**$ 1,656,471**	$ 1,916,432	$ 1,656,471

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

26. Borrowings

On November 24, 2010, Eagle Energy Acquisitions LP entered into a credit facility with a U.S. affiliate of a Canadian chartered bank. At December 31, 2011, the borrowing base under the credit facility was $US 16.5 million. The credit facility provides for a semi-annual evaluation each April 1 and October 1. Subsequent to December 31, 2011, the borrowing base was increased to $US 31million as a result of a scheduled semi-annual evaluation. Refer to Note 33.

As at December 31, 2011, no amounts have been or are outstanding under this credit facility. 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. 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 December 31, 2011 there were no covenant violations and no amounts outstanding under the $US 16.5 million borrowing base nor have there been any draws during the period covered by these consolidated financial statements.

27. Provision for liabilities and other charges

	Provision for decommissioning costs		
		December 31, 2011	**December 31, 2010**
Beginning Balance	$	217,380	-
Additions		240,085	217,380
Changes in estimates		-	-
Adjustment for change in risk-free discount rate		33,292	-
Accretion (unwinding of discount)		11,674	-
Ending Balance	**$**	502,431	217,380

The decommissioning provision reflects the present value of internal estimates of future decommissioning costs of the Trust's net ownership position in oil and gas wells and related facilities at the relevant balance sheet date determined using local pricing conditions and requirements. These costs are expected to be incurred between 2012 and 2032. The timing of payments related to provisions is uncertain and is dependent on various items which are not always within Management's control.

The provision was estimated using existing technology, at current prices (adjusted for inflation assuming 2% inflation rate), and discounted using a risk-free discount rate of 3.0% (December 31, 2010 – 4%). A 1% decrease in the risk-free discount rate would have increased the liability by $33,292 as at December 31, 2011.

Included in the balance at December 31, 2010, is $139,761 of decommissioning liability recorded as part of the Salt Flat acquisition. See "Acquisitions" note 7. The total undiscounted decommissioning liability at December 31, 2011 was $730,813 (December 31, 2010 - $394,036).

28. Trust capital

Authorized

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

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

Trust units outstanding			December 31, 2011		December 31, 2010
	Number of units		**Amount**	**Number of units**	**Amount**
Beginning balance	17,624,081	$	159,577,493	-	$ -
Issuance of Trust capital	919,518		8,961,200	17,624,081	173,090,827
Reclass from unit based compensation for option exercise	-		48,700	-	-
Trust Unit issuance costs	-		(412,116)	-	(13,513,334)
Ending balance	**18,543,599**	**$**	**168,175,277**	**17,624,081**	**$ 159,577,493**

Other than the issuance of 10,000 units for proceeds of $91,200 relating to the exercise of Trust unit options, all other issuances of Trust capital related to the DRIP (as described below).

For the period ended December 31, 2010, the Trust incurred unit issue costs, relating to the initial public offering ("IPO"), of $13,513,334. For the year ended December 31, 2011 the Trust recognized an additional $39,486 of unit issue costs associated with the IPO. Additionally, the Trust incurred $46,053 in conjunction with implementing the DRIP (as described below). The Trust recognized $326,577 of Trust unit issuance costs for various financing projects in progress. None of these transactions resulted in the issuance of additional units during the period. In the event that any of these financing projects do not proceed, the associated cost of the project will be expensed.

Trust units issued, but not classified as outstanding

Refer to note 10 "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.

DRIP Plan (Premium Distribution and Dividend Reinvestment Plan)

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

29. Cash generated from operations

	Year Ended December 31, 2011	Year Ended December 31, 2010
Income (loss) for the period	$ (1,213,585)	$ (3,213,531)
Adjustments for:		
Depreciation, depletion and amortization	12,609,549	581,554
Unit-based compensation	7,847,492	673,123
Debt conversion costs	-	1,620,425
Unrealized risk management loss	503,121	-
Finance expense	106,165	50,353
	19,852,742	**(288,076)**
Changes in working capital:		
Trade and other receivables	(4,130,779)	(1,327,501)
Prepaid expenses	(237,783)	(61,416)
Trade and other payables	(1,172,076)	7,047,148
	(5,540,639)	**5,658,231**
Cash (used in) generated from operations	14,312,104	5,370,155
Income taxes paid	-	-
Net cash generated by operating activities	**$ 14,312,104**	**$ 5,370,155**

Summary of non-cash items

	Year Ended December 31, 2011	Year Ended December 31, 2010
Operating cash flow		
Unit-based compensation	$ 7,847,492	$ 673,123
Unrealized risk management loss	503,121	-
Investment activities		
Purchase of oil and gas properties via issuance of trust units	$ -	$ (20,000,000)
Depreciation, depletion and amortization	12,609,549	581,534
Provision for decommissioning costs	254,471	77,619
Accretion of decommissioning provision	11,674	-
Financing activities		
Purchase of oil and gas properties via issuance of trust units	$ -	$ 20,000,000
Debt conversion costs	-	1,620,425
Finance expense-amortization of deferred financing costs	94,492	7,488

30. Convertible promissory notes

On September 7, September 22 and October 4, 2010, the Trust issued a total of $1,577,560 principal amount of convertible promissory notes. The notes had a 15% annual interest rate and were issued to fund expenses of the initial public offering. Each note was automatically converted into units (as to both the outstanding principal amount of the notes as well as all accrued interest on such notes) concurrently with the closing of the initial public offering of the units of the Trust on November 24, 2010.

31. 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 "Commitments" note 32 regarding operating lease commitments.

No amounts were owing to this related party as at December 31, 2011 and December 31, 2010. For the year ended December 31, 2011 administrative expenses included $ 99,000 (December 31, 2010 - $3,250) for amounts billed from this related party.

32. Commitments

Operating lease commitment – head office lease in Calgary, Alberta

The initial term of the sub-lease agreement was for 6 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 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 are $51,000, with $8,500 remaining as at December 31, 2011.

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 21 months and approximately $US 236,900 remaining at December 31, 2011. In $CA the remaining future minimum lease payments approximate $240,900 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.017.

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. Future minimum payments during the term of the sub-lease are $US 20,600, with $US 13,200 remaining at December 31, 2011. In $CA, the remaining future minimum lease payments approximate $13,400 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.017.

Drilling rig commitment – nine wells

The Trust, through its operations in the Salt Flat Field, entered into a nine well drilling rig commitment agreement effective December 15, 2011. At December 31, 2011, no wells had been drilled under the agreement. Future minimum payments are estimated to be approximately $US 1,340,000 which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 1,072,000. In $CA the net future commitment approximates $1,090,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.017.

Settlement agreement

The Trust, through its operations in the Salt Flat Field, signed a settlement agreement with a third party to reimburse them for certain future costs relating to damages to the producing formation of a nearby well. Future costs associated with this settlement agreement are estimated to be $US 75,000, which is 100% of the commitment. The net commitment to the Trust, based upon its 80% interest, equates to $US 60,000. In $CA the net future commitment approximates $61,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.017.

33. Subsequent events

Commodity hedging

On February 17, 2012, the Trust entered into a financial contract to further mitigate the effects of fluctuating prices on a portion of its production as follows: 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.

Drilling rig commitment – two wells

The Trust, through its operations in the Salt Flat Field, entered into a two well drilling rig commitment agreement effective February 13, 2012. This is in addition to the drilling rig commitment agreement effective December 15, 2011, see note 32 Commitments. Future minimum payments are estimated to be approximately $US 255,000, which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 204,000. In $CA the net future commitment approximates $207,400 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.017.

Increase in Eagle Energy Acquisitions LP borrowing base

Effective March 16, 2012, the borrowing base under the credit facility was increased to $US 31 million. All other terms and conditions, as described in note 26, remain unchanged.

Corporate Information

Board of Directors

David M. Fitzpatrick
Chairman of the Board

Bruce K. Gibson (1)
Director

Warren D. Steckley (2)
Director

Joseph W. Blandford (3)
Director

Richard W. Clark
President, Chief Executive Officer and Director

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

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Officers

Richard W. Clark
President, Chief Executive Officer and Director

Peter L. Churcher
Chief Operating Officer

Kelly A. Tomyn
Vice President, Finance and Chief Financial Officer

Robert J. Cunningham
Vice President, Business Development

Dusty J. Dumas
U.S. Controller

Robert D. McCue, Bennett Jones LLP
Corporate Secretary

Auditors

PricewaterhouseCoopers LLC

Trustee and Transfer Agent

Computershare Trust Company of Canada

Engineering Consultants

GLJ Petroleum Consultants Ltd.

Bankers

Bank of Nova Scotia

Legal Counsel

Bennett Jones LLP

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