EXPERTISE • QUALITY • INCOME

Third Quarter 2015 Financial Report

EAGLE ENERGY™
TRUST

EAGLE ENERGY™ TRUST

Management's Discussion and Analysis

November 5, 2015

This Management's Discussion and Analysis ("**MD&A**") of financial condition and results of operations for Eagle Energy Trust (the "**Trust**" or "**Eagle**"), dated November 5, 2015, should be read in conjunction with the Trust's unaudited condensed consolidated interim financial statements and accompanying notes for the three months and nine months ended September 30, 2015 ("**Interim Financial Statements**") and the Trust's audited consolidated financial statements and accompanying notes and related MD&A for the year ended December 31, 2014 and the Trust's Annual Information Form dated March 19, 2015 ("**AIF**"), which are available online at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

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

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

The foreign exchange rate at September 30, 2015 was $US 1.00 equal to $CA 1.34 (December 31, 2014 - $US 1.00 equal to $CA 1.16), and the average foreign exchange rate for the nine months ended September 30, 2015 was $US 1.00 equal to $CA 1.26 (for the nine months ended September 30, 2014 - $US 1.00 equal to $CA 1.12).

Throughout this MD&A, Eagle Energy Trust and its subsidiaries are collectively referred to as "the Trust" or "Eagle" for purposes of convenience. In addition, references to the results of operations refer to operations of the Trust's subsidiaries in the U.S. and in Canada.

This MD&A contains information that is forward-looking and refers to non-IFRS financial measures. Investors should read the "Note about Forward-Looking Statements" and "Non-IFRS Financial Measures" sections at the end of this MD&A.

Financial data other than non-IFRS financial measures has been prepared in accordance with IFRS.

Overview of the Trust

Eagle Energy Trust is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The Trust's activities are restricted to owning property (other than real property or interests in real property), and it does not carry on business. The Trust's stated business strategy is to invest in its operating subsidiaries to fund the acquisition of petroleum reserves and production with unexploited low risk development potential in the United States and Canada and to pay out a portion of available cash to unitholders of the Trust on a monthly basis. The Trust was created to provide investors with a sustainable business model while delivering stable growth in production and overall growth through accretive acquisitions.

This MD&A discusses the Trust's operating segments in the United States and Canada, in addition to its Corporate segment. The United States segment relates to the Trust's assets in Texas and Oklahoma and the Canadian segment relates to the Trust's assets in Alberta. The Corporate segment includes expenditures related to the Trust's hedging program, public company, and other expenses incurred in the overall financing and administration of the Trust.

Highlights for the Three Months ended September 30, 2015

- On August 20, 2015, the Trust acquired a private oil and gas company ("Privateco") with petroleum assets in the Twining Field in Alberta. The cost to assume Privateco's debt, working capital and acquire its equity totaled $27.3 million and was funded from Eagle's existing $US 80 million credit facility. This acquisition marked another significant step in Eagle's expansion into Canada with the establishment of a Canadian-based operations team. The Twining properties have been integrated into Eagle's operations and Eagle has commenced production improvements.

- Third quarter average working interest sales volumes of 3,607 barrels of oil equivalent per day ("boe/d") (93% oil) marked the highest level in the Trust's five year history with production on track to meet 2015 full year guidance of 3,150 to 3,350 boe/d. Factors contributing to the strong production levels included drilling results exceeding expectations in the Salt Flat field in Texas and the August acquisition of Privateco.

- The new salt water disposal facility at Hardeman, Texas was put into service and is expected to reduce operating costs in the southern part of the Hardeman area.

- Eagle continues to maintain a strong balance sheet and financial flexibility after the Privateco transaction. At the end of the third quarter, the Trust had net debt (bank debt less cash on hand, receivables and prepaid expenses plus trade and distributions payable) of $CA 61.6 million, resulting liquidity of $CA 45.2 million, 42% undrawn on its existing $US 80 million credit facility, 2015 year-end projected debt to trailing cash flow ratio of 2.3x and a corporate payout ratio maintained below 100%.

2015 Outlook

This outlook section is intended to provide unitholders with information about Eagle's expectations for production and capital expenditures for 2015. Readers are cautioned that the information may not be appropriate for any other purpose. This information constitutes forward-looking information. Readers should note the assumptions, risks and discussions under "Note about Forward-Looking Statements" at the end of this MD&A.

Eagle's 2015 guidance for its capital budget, production and operating costs remains unchanged from when it was revised on August 20, 2015 to include the Privateco acquisition (refer to the "Acquisition" section of this MD&A). Sensitivities of forecast funds flow from operations, corporate payout ratio and debt to trailing cash flow to changes in production levels and West Texas Intermediate ("WTI") prices have been updated to include nine months of actual results and three months of forecast results using WTI price ranges of $US 40.00 to $US 50.00 (previously $US 50.00 to $US 60.00). Eagle's guidance is summarized as follows:

	2015 Guidance	**Notes**
Capital Budget	$16.2 mm	1
Working Interest Production	3,150 to 3,350 boe/d	2
Operating Costs per month	$2.0 to $2.2 mm	3
Funds Flow from Operations	$28.4 mm	4
Debt to Trailing Cash Flow	2.3x	
Field Netback (excluding Hedges)	$19.63/boe	

Notes:

(1) The 2015 capital budget of $16.2 million consists of $US 11.4 million for Eagle's operations in the United States and $1.4 million for Eagle's operations in Canada.

a. Based on a mid-range forecast $US 45.00 WTI oil price for the last three months of 2015, the 2015 capital budget delivers an annualized distribution of $0.36 per unit and a corporate payout ratio of 97%.

b. Eagle's 2015 capital budget of $16.2 million consists of the following:

- Salt Flat, Texas
  - 3 (3.0 net) horizontal oil wells
  - Seismic processing, horizontal pump installations

- Hardeman, Texas and Oklahoma
  - 5 (5.0 net) vertical wells (previously 3 wells)
  - 1 (1.0 net) salt water disposal well

- Facilities and seismic capital

o Dixonville, Alberta (non-operated)
  - Maintenance capital on waterflood

o Twining, Alberta
  - No horizontal drilling is now planned for 2015. The two wells previously slated for 2015 are expected to be drilled in 2016.

(2) 2015 production forecast consists of 94% oil, 2% natural gas liquids (**"NGLs"**) and 4% gas.

(3) 2015 forecast operating costs result in field netbacks (excluding hedges) of approximately $19.63 per boe at a mid-range price forecast of $US 45.00 WTI.

(4) 2015 forecast funds flow from operations is approximately $28.4 million based on the following assumptions:

a. Average working interest production of 3,250 boe/d (the mid-point of the guidance range);

b. Forecast mid-range pricing at $US 45.00 per barrel WTI oil, $US 3.00 per Mcf NYMEX gas and $US 15.75 per barrel of NGL (NGL price is calculated as 35% of the WTI price) for the last three months of 2015;

c. Differential to WTI is a $US 2.25 discount per barrel in Salt Flat, a $US 2.70 discount per barrel in Hardeman, a $CA 20.50 discount per barrel in Dixonville, and a $CA 16.50 discount per barrel in Twining;

d. Average operating costs of $2.1 million per month ($US 0.9 million per month for Eagle's operations in the United States and $0.9 million per month for Eagle's operations in Canada) being the mid-point of the guidance range; and

e. Foreign exchange rate of $US 1.00 equal to $CA 1.32.

A table showing the sensitivity of Eagle's funds flow from operations to changes in commodity price and production is set out below under the heading "2015 Sensitivities".

2015 Sensitivities

The following tables show the sensitivity of Eagle's 2015 funds flow from operations, corporate payout ratio and net debt to trailing cash flow to changes in commodity prices and production:

Sensitivity to Commodity Price

	2015 Average WTI (Production 3,250 boe/d)		
	$US 40 (FX 1.32)	$US 45 (FX 1.32)	$US 50 (FX 1.32)
Funds Flow from Operations	$27.5	$28.4	$29.4
Corporate Payout Ratio	101%	97%	94%
Debt to Trailing Cash Flow	2.4x	2.3x	2.2x

Sensitivity to Production

	2015 Average Production (boe/d) (WTI $US 45, F/X 1.32)		
	3,150	**3,250**	**3,350**
Funds Flow from Operations	$27.7	$28.4	$29.1
Corporate Payout Ratio	100%	97%	95%
Debt to Trailing Cash Flow	2.4x	2.3x	2.3x

Assumptions:

(1) Distributions of $0.03 per unit per month.

(2) No new equity issued.

(3) Operating costs of $2.1 million per month (the mid-point of the guidance range).

(4) Differential to WTI held constant.

(5) The foreign exchange rate is assumed to be $US 1.00 equal to $CA 1.32.

Acquisition

On August 20, 2015, the Trust acquired Privateco with petroleum assets in the Twining field in Alberta. The cost to assume Privateco's debt, working capital and acquire its equity totaled $27.3 million and was funded from Eagle's existing $US 80 million credit facility. The acquisition was completed by the amalgamation of Privateco with a newly incorporated operating subsidiary of the Trust and marked another significant step in Eagle's expansion into Canada with the establishment of a Canadian-based operations team.

Privateco had been redeveloping the Twining field with horizontal wells in the Pekisko Pool, which is estimated to contain discovered oil initially-in-place of approximately 900 million barrels and have a current recovery factor of less than 5%. Prior to its acquisition, Privateco had drilled 10 horizontal wells and built a new battery to handle current and future development plans, which include over 30 locations.

Acquisition highlights are:

- 2.1 MMboe of proved reserves and 7.2 MMboe of proved plus probable reserves.
- Production of approximately 750 boe/d from 92 gross (48 net) wells in the Twining field, one of the largest Pekisko oil pools in the Western Canadian Sedimentary Basin.
- A portfolio of over 30 drilling locations, which is anticipated to extend Eagle's inventory necessary to sustain current production rates for over five years.
- 64% light oil and natural gas liquids.
- 80% working interest in approximately 41,502 gross (32,650 net) acres.
- Majority operated.
- Approximately $92 million of tax pools, including approximately $40 million of non-capital losses.

Sensitivities

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

	Quarterly impact on ➔	Funds flow from operations ($000's)	Funds flow from operations / unit(1)
Gas price(2)	+ USD $0.10/mcf Henry HUB	4	-
Oil price(2)	+ USD $1.00/bbl WTI	258	0.01
Gas production	+1000 mcf/d	125	-
Oil production	+100 bbls/d	209	0.01
Currency(2)	+CDN weaken by $0.01	60	-
Interest rate	+1% prime	(116)	-

Notes:

(1) Per unit figures are based on 34,990,619 weighted average basic units outstanding for the nine months ended September 30, 2015.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate equal to year to date average working interest sales volumes of 3,214 boe/d.

Consolidated Results of Operations

Production

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Oil (bbl/d)	3,363	2,342	44	3,059	2,539	20
Natural gas (Mcf/d)	1,018	1,520	(33)	564	1,539	(63)
Natural gas liquids (bbl/d)	74	263	(72)	62	274	(77)
Oil equivalent sales volumes (boe/d @ 6:1)	**3,607**	2,859	26	**3,214**	3,069	5

Working interest sales volumes for the third quarter of 2015 averaged 3,607 boe/d (93% oil, 2% natural gas liquids, 5% natural gas).

Revenue

$000's	**Three Months Ended September 30, 2015**	**Three Months Ended September 30, 2014**	**%**	**Nine Months Ended September 30, 2015**	**Nine Months Ended September 30, 2014**	**%**
Oil	17,209	21,965	(22)	46,663	73,214	(36)
Natural gas	262	564	(54)	415	1,886	(78)
Natural gas liquids	141	841	(83)	307	2,800	(89)
Other	276	196	41	705	441	60
Sales before royalties	**17,888**	23,566	(24)	**48,090**	78,341	(39)

Realized prices						
Oil ($/bbl)	55.61	101.92	(45)	55.88	105.62	(47)
Natural gas ($/Mcf)	2.80	4.05	(31)	2.70	4.49	(40)
Natural gas liquids ($/bbl)	20.58	34.72	(41)	18.27	37.46	(51)
Other ($/bbl)	0.83	0.75	(11)	0.80	0.53	52
Sales before royalties ($/boe)	53.90	89.61	(40)	54.80	93.49	(41)
Royalties ($/boe)	(13.44)	(24.42)	(45)	(13.19)	(25.54)	(48)
Revenue ($/boe)	**40.46**	65.19	**(38)**	**41.61**	**67.95**	(39)

Benchmark prices[(1)]						
Oil – WTI ($/bbl)	**58.50**	97.17	(40)	**64.26**	99.60	(35)
Natural gas – Henry HUB ($/Mcf)	**3.45**	3.95	(13)	**3.48**	4.42	(21)

Notes:

(1) Converted from $US at the average foreign exchange rate for the period indicated

The Trust's quarterly revenue is 96% derived from oil. For the three months ended September 30, 2015, realized oil prices decreased 8% when compared to the second quarter of 2015 due to a decrease in the quarter over quarter benchmark WTI price being partially offset by narrower negative price differentials.

For the three and nine months ended September 30, 2015, sales before royalties decreased by 24% and 39%, respectively, when compared to the prior year. The decrease is attributable to lower realized commodity prices resulting from the decline in the WTI benchmark price over the 2014 comparative period being partially offset by the increase in sales volumes over the same periods.

Realized oil prices in Canadian dollars for the three and nine months ended September 2015 decreased by 45% and 47%, respectively. This decrease exceeded the benchmark WTI decrease due to wider negative price differentials.

There is a quality differential between the benchmark $US WTI price and the $US price realized by the Trust. Eagle enters into field marketing contracts to obtain the most favourable pricing. Management monitors pricing regularly and endeavours to maximize realized sales prices while minimizing counterparty risk. For the Salt Flat properties, the field marketing contracts use Louisiana Light Sweet ("LLS") as a benchmark reference price instead of WTI. For the period July 1, 2015 to November 30, 2015, Eagle negotiated a new contract which improved the fixed field pricing adjustment by $US 1.75 per barrel, while continuing to allow the LLS-WTI differential and the Argus P+ differential to float. Eagle is in the process of negotiating renewal terms of this contract. For the Hardeman properties, the field marketing contracts in place are a month to month term and use WTI as a reference price. These contracts hold all other field pricing adjustments fixed.

For the Dixonville properties in Canada, the entire differential to WTI, including quality and transportation, is approximately $CA 20.50 discount per barrel, but fluctuates. For the Twining properties in Canada, the entire differential to WTI, including quality and transportation, is approximately $CA 16.50 discount per barrel, but fluctuates.

On October 1, 2015, to mitigate the effect of fluctuating differentials on a portion of its production, the Trust entered into a fixed price financial swap on 1,000 barrels per day of oil fixing the price differential between Edmonton light sweet and WTI at $US 3.65 per barrel for the period December 1, 2015 to December 31, 2016. The portion of the differential between Edmonton light sweet and realized field price was not fixed in this transaction. The differential being hedged is currently narrower than the historical WTI to Edmonton light sweet differential.

The above prices do not include realized gains or losses from financial commodity contracts, which amounted to a realized gain of $3.8 million ($11.37/boe) for the three months ended September 30, 2015 and a realized gain of $16.7 million ($19.03/boe) for the nine months ended September 30, 2015. See *Realized and unrealized risk management gain/loss.*

The overall royalty rate of approximately 25% for the three months ended September 30, 2015 and 24% for the nine months ended September 30, 2015 was lower than the prior year comparative periods due to the sliding scale nature of royalties paid on Canadian properties. Crown royalty rates in Alberta depend on four components: (i) production volumes, (ii) commodity prices, (iii) product density, and (iv) Crown royalty percentage. Commodity prices have trended downward since December 31, 2014, causing a downward trend in Alberta Crown royalty rates.

Operating Costs

$000's	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Operating costs	5,868	4,148	41	16,468	12,705	30
Transportation and marketing expenses	605	164	269	1,638	553	196
	6,473	4,312		**18,106**	13,258	
Per boe:						
Operating costs	17.68	15.77	12	18.77	15.16	24
Transportation and marketing expenses	1.82	0.62	194	1.87	0.66	183
	19.50	16.39	19	**20.64**	15.82	30

Operating costs for the three months ended September 30, 2015 are comprised primarily of power (24%), oil transportation (10%), water disposal fees (10%), field salaries (5%) and chemicals (5%).

The operating expense increase for the nine months ended 2015 versus 2014 is due to a large amount of workover expenses and a casing repair in Hardeman early in 2015. Operating expenses on a quarter over quarter basis decreased by 4%.

Third quarter operating costs on a per-barrel basis were on par with the second quarter. The Trust intends to continue to improve efficiencies and maintains its 2015 operating expense guidance of $2.0 million to $2.2 million per month. Refer to the “Segmented Operations” section of this MD&A.

Depreciation, Depletion and Amortization

$/boe	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Depreciation, depletion and amortization	**8,173**	9,098	(10)	**20,376**	28,610	(29)
Per boe	**24.62**	34.41	(28)	**23.22**	33.97	(32)

The depletion, depreciation, and amortization provision for the three and nine months ended September 30, 2015 was based on proved plus probable reserves, including the future development costs associated with those reserves, as outlined in the year-end 2014 reserves evaluation report prepared by the Trust’s independent reserves evaluators, together with the reserves associated with the Privateco acquisition.

The disposition of the Permian properties in Martin County, Texas and the acquisition of the Dixonville and Twining properties in Alberta significantly changed the nature of Eagle's asset base. Forecast corporate declines have dropped from approximately 30% to under 20%, with the result being a significant reduction in required sustaining capital and lower future development costs associated with the reserves. As commodity prices recover, it is anticipated that the amount of cash left over after funding sustaining capital requirements will rise on a relative percentage basis.

Field Netback

	Three Months Ended September 30, 2015		Three Months Ended September 30, 2014		Nine Months Ended September 30, 2015		Nine Months Ended September 30, 2014	
$000's		**/boe**		/boe		**/boe**		/boe
Sales before royalties	17,888	53.90	23,566	89.61	48,090	54.80	78,341	93.49
Royalties	(4,460)	(13.44)	(6,423)	(24.42)	(11,572)	(13.19)	(21,403)	(25.54)
Operating expenses	(5,868)	(17.68)	(4,148)	(15.77)	(16,468)	(18.77)	(12,705)	(15.16)
Transportation and marketing expenses	(605)	(1.82)	(164)	(0.62)	(1,638)	(1.87)	(553)	(0.66)
Field netback	**6,955**	**20.96**	12,831	48.80	**18,412**	**20.97**	43,680	52.13
Sales volumes (boe/d)		**3,607**		2,859		**3,214**		3,069

During the quarter, benchmark WTI averaged $CA 58.50 per barrel and the Trust realized a field netback of $20.96 per boe. For the nine months ended September 30, 2015, benchmark WTI averaged $CA 64.26 per barrel and the Trust realized a field netback of $20.97 per boe. When compared to the prior year comparative periods, the decrease in field netback is primarily due to the sharp drop in commodity prices. Refer to the "Segmented operations" section of this MD&A.

Field netback is a Non-IFRS financial measure. See "Non-IFRS Financial Measures".

Realized and Unrealized Risk Management Gain/Loss

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

	Volume	***Measure***	***Beginning***	***Term***	***Floor $US***	***Ceiling $US***
Oil Fixed Price						
NYMEX (i)	190	bbls/d	Jan-15	Dec-15	85.40	85.40
NYMEX (i)	400	bbls/d	Jul-15	Dec-15	87.90	87.90
NYMEX (i)	400	bbls/d	Oct-15	Dec-15	57.10	57.10
NYMEX (i)	500	bbls/d	Jan-16	Dec-16	65.00	65.00
NYMEX (i)	500	bbls/d	Jan 16	Dec-16	53.32	53.32
Gas Fixed Price						
CGPR ALT daily spot	1,500	GJs/day	Jan-16	Dec-16	2.83	2.83

(i) Represents a fixed price financial swap transaction with a set forward sale price (WTI reference prices).

$000's	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Realized gain (loss) - Commodity	3,774	(612)	(717)	16,696	(2,962)	(664)
Unrealized gain (loss) - Commodity	3,808	7,569	(50)	(8,359)	2,609	(420)
Net gain (loss) - Commodity	7,582	6,957	9	8,337	(353)	(2,462)
Realized gain (loss) - Foreign exchange	-	(13)	-	-	(42)	-
Unrealized gain (loss) - Foreign exchange	-	(78)	-	-	(81)	-
Net gain (loss) - Foreign exchange	-	(91)	-	-	(123)	-
Total net gain (loss)	**7,582**	6,866	10	**8,337**	(476)	(1,852)

On a year-over-year basis, the net value of the commodity price contracts has increased. The net value of the contracts is dependent upon current and forward commodity pricing and, in the case of realized gains and losses, the price of the contract relative to the benchmark oil price at time of settlement. Although the Trust currently has no intention of unwinding the contracts that are in place, it is required to calculate and record, using a mark-to-market valuation, the fair value of the remaining term of the contracts at the end of each reporting period, hence the change in value of the unrealized portion of the commodity contracts. Compared to the second quarter of 2015, the forward commodity pricing environment decreased considerably, causing the future values of the unrealized contracts to increase on the balance sheet at September 30, 2015.

Eagle had 1,290 barrels of oil per day hedged at an average WTI price of $US 69.72 per barrel during the third quarter of 2015. For the fourth quarter of 2015, 990 barrels of oil per day are hedged at an average WTI price of $US 74.98. In 2016, Eagle has 1,000 barrels of oil per day hedged at an average WTI price of $US 59.16. In addition, Eagle has a natural gas hedge on 1,500 GJs per day at a fixed price of $CA 2.83 per GJ for the period of January 1, 2016 to December 31, 2016.

On October 1, 2015, the Trust entered into a fixed price financial swap on 1,000 barrels per day of oil fixing the differential between Edmonton light sweet and WTI at $US 3.65 per barrel for the period December 1, 2015 to December 31, 2016.

Finance Expense

$000's	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Finance expense	**653**	412	58	2,109	2,376	(11)
Per boe	1.64	1.57	4	1.93	2.84	(32)

For the three months ended September 30, 2015, finance expense increased over the comparative prior period due to the increase of the Trust's outstanding advances on its credit facility. Finance expenses for the nine months ended September 30, 2015 decreased year-over-year due in part to the full retirement of the Trust's outstanding advances on its credit facility following the August 29, 2014 disposition of the Permian properties.

As of September 30, 2015, the effective interest rate on bank debt for the period was 3.3% compared to 4.1% for the comparable period in 2014. During the quarter, the Trust borrowed by way of banker's acceptance (funds drawn were denominated in Canadian dollars), which was lower than the prime rate option on its borrowings. The prior year's comparative quarter utilized borrowings by way of LIBOR loans (funds drawn were denominated in US dollars), which was lower than the base rate option on its borrowings.

Administrative Expenses

$000's	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Administrative expenses	**2,880**	4,212	(32)	**7,684**	9,776	(21)
Per boe	**8.68**	16.02	(46)	**8.76**	11.67	(25)

Total administrative expenses for the three months ended September 30, 2015 were $2.9 million, representing approximately 26% of full year 2015 expected levels. For the nine months ended September 30, 2015, total administrative expenses were $7.7 million, representing approximately 70% of full year expected levels. Staff and related employment costs, office costs and one-time deal transaction costs related to the Privateco acquisition (refer to the "Acquisition" section of this MD&A) accounted for 69%, 14% and 12% of administrative expenses for the nine months ended September 30, 2015, respectively.

Unit Based Compensation

$000's	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Unit-based compensation expense (recovery)	**(1,225)**	(2,112)	(42)	**(357)**	(4,886)	(93)

A non-cash unit-based compensation recovery of $1.2 million was recorded during the third quarter of 2015 due primarily to a 61% decrease in the unit price since the second quarter of 2015. The unit price at September 30, 2015 was also significantly below the unit price for the quarter ended September 30, 2014.

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

The actual total value received by holders of the unit-based compensation awards will depend on the accumulated distributions actually paid by the Trust combined with: (1) the actual year over year price appreciation of the trust units (for holders of restricted unit rights and unit rights); or (2) the actual price of the units relative to the exercise price of the options at the time the options are exercised (for holders of options and which would not result in a cash outlay for the Trust).

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

From one reporting period to the next, changes in the closing price of the units, risk free rate and expected future unit price volatility will increase or decrease the fair values of the unit-based awards as calculated under the Black-Scholes valuation model. These fair value changes cause corresponding swings in the amount recorded in the income statement. For the nine months ended September 30, 2015, the recorded recovery was due to a decrease in the year to date price of the Trust's units. The weighted average exercise price of the unit options of $5.64 remains significantly above the September 30, 2015 closing unit price of $1.91.

During the third quarter, $56,925 was paid out in cash for amounts related to vested restricted unit rights and $170,760 was recorded for the nine months ended September 30, 2015 (three and nine months ended September 30, 2014 - $166,007 and $527,648, respectively). The decrease in payments year over year is primarily due to the reduction in Eagle's monthly cash distribution. Effective with the January 23, 2015 payment (for distributions declared in December 2014), the distribution amount paid per unit was reduced from $0.0875 to $0.03 per unit per month.

Impairment

United States - Salt Flat and Hardeman Cash Generating Units

As a result of the current price environment, the Trust's US assets were assessed for impairment at September 30, 2015. The impairment test used an expected cash flow approach based on internal cash flow estimates at September 30, 2015. A risk-adjusted discount rate of 10% was used for all areas and a WTI price of US$ 50.00 for the remainder of 2015, US$ 55.00 in 2016, US$ 61.20 in 2017, US$ 65.00 in 2018, US$ 69.00 in 2019, US$ 73.10 in 2020, US$ 77.30 in 2021, US$ 81.60 in 2022, US$ 86.20 in 2023, US$ 87.90 in 2024 and US$ 89.60 for the remainder. Based on the analysis, the Trust recorded an impairment provision of US$ 20.9 million in the Salt Flat cash generating unit and US$ 8.1 million in the Hardeman cash generating unit.

The calculation of the recoverable amount is sensitive to the discount rate and prices. A 2% increase in the discount rate would result in an after-tax impairment charge of an additional US$ 2.4 million impaired in Salt Flat, for a total impairment of US$ 23.3 million and an additional US$ 2.8 million in Hardeman for a total of US$ 10.9 million. A 5% decrease in prices would result in an after-tax impairment of an additional US$ 5.2 million (total US$ 26.1 million) in Salt Flat and US$ 3.4 million in Hardeman (total US$ 11.5 million).

Canada - Dixonville Cash Generating Unit

At September 30, 2015, the Trust assessed its assets in the Dixonville area in Alberta for impairment, as a result of the current price environment. The impairment test used an expected cash flow approach based on internal cash flow estimates at September 30, 2015. A risk-adjusted discount rate of 11.6% was used and an Edmonton Par price of $49.90 for the remainder of 2015, $56.60 for 2016, $61.70 for 2017, $65.60 for 2018, $68.00 for 2019, $72.20 for 2020, $76.50 for 2021, $81.00 for 2022, $85.70 for 2023, $87.40 for 2024 and $89.00 for the remainder. Based on the analysis, the Trust recorded an impairment provision of $24.7 million in Dixonville at September 30, 2015.

The calculation of the recoverable amount is sensitive to the discount rate and prices. A 2% increase in the discount rate would result in an additional impairment of $12.8 million and a 5% decrease in prices would result in an after-tax impairment of an additional $6.2 million.

Foreign Exchange Loss (Gain) on Intercompany Loan

The foreign exchange loss (gain) on an intercompany loan is a non-cash entry resulting from the U.S. subsidiary holding a Canadian dollar denominated loan issued by its parent, Eagle Energy Trust. Although the intercompany loan is eliminated on consolidation, it is no longer considered part of the net investment in the subsidiary because amounts have been repaid, thus any related period end foreign exchange translation adjustment is recorded in earnings or loss.

For the nine months ended September 30, 2015, the Trust recorded a foreign exchange gain of $11.7 million. The foreign exchange gain of $5.4 million during the three months ended September 30, 2015 was due to an increase in the average foreign exchange rate from the previous quarter.

Summary of Quarterly Results

	Q3/2015	Q2/2015	Q1/2015	Q4/2014	Q3/2014	Q2/2014	Q1/2014	Q4/2013
($000's except for boe/d and per unit amounts)								
Sales volumes – boe/d	3,607	3,034	2,995	1,929	2,859	3,341	3,010	2,994
Revenue, net of royalties	13,428	12,884	10,206	10,238	17,143	20,821	18,973	17,119
per boe	40.46	46.66	37.86	57.67	65.19	68.48	70.04	62.15
Field netback	6,956	7,713	3,744	6,841	12,832	16,144	14,705	13,106
per boe	20.96	27.94	13.89	38.54	48.80	53.10	54.29	47.58
Funds flow from operations	7,331	10,532	7,727	5,670	7,476	10,471	10,341	8,794
per boe	22.09	38.14	28.67	31.94	28.43	34.44	38.18	31.93
per unit – basic	0.21	0.30	0.22	0.16	0.22	0.32	0.32	0.28
per unit – diluted	0.21	0.30	0.22	0.15	0.16	0.28	0.25	0.28
Earnings (loss)	(51,786)	(6,541)	5,477	(35,192)	8,104	(23,158)	2,218	156
per unit – basic	(1.48)	(0.19)	0.16	(1.01)	0.24	(0.70)	0.07	-
per unit - diluted	(1.48)	(0.19)	0.16	(1.13)	0.18	(0.70)	0.02	-
Cash distributions declared	3,143	3,130	3,153	7,159	9,036	8,775	8,555	8,376
per issued unit	0.09	0.09	0.09	0.21	0.26	0.26	0.26	0.26
Current assets	21,862	13,382	31,459	33,245	76,566	8,802	9,116	9,889
Current liabilities	8,033	7,754	8,642	10,720	13,587	32,878	33,348	30,461
Total assets	228,959	245,009	265,342	257,172	240,458	320,182	356,332	335,679
Total non-current liabilities	91,316	52,012	60,835	57,547	2,565	80,126	79,684	70,521
Unitholders' equity	129,611	185,243	195,865	188,905	224,306	207,178	243,300	234,697
Units issued	34,893	34,961	35,023	35,017	34,821	33,739	32,836	32,149

Funds flow from operations is a non-IFRS measure. See "Non-IFRS Financial Measures".

For the three months ended September 30, 2015, sales volumes increased when compared to the previous quarter due to the Privateco acquisition (refer to the "Acquisition" section of this MD&A) and drilling results exceeding expectations in the Salt Flat field.

Despite a quarter-over-quarter increase in production, funds flow from operations decreased in the third quarter of 2015 due to lower realized commodity prices. Generally, in times of decreasing prices, funds flow from operations decreases faster than decreases in sales volumes because certain expenses tend to be more fixed in nature, such as general and administrative expenses, and do not change with sales volumes.

Earnings (loss) on a quarterly basis often does not move directionally or by the same amount as movements in funds flow from operations. This is primarily due to items of a non-cash nature that factor into the calculation of earnings (loss), and those that are required to be fair valued at each quarter end. Third quarter 2015 funds flow from operations decreased 30% from the second quarter 2015 while the third quarter loss increased by a greater amount from the second quarter primarily due to a non-cash impairment of oil and gas properties owing to the decrease in commodity prices since 2014 year end.

Eagle had 1,290 barrels of oil per day hedged at an average WTI price of $US 69.72 per barrel during the third quarter of 2015. For the fourth quarter of 2015, 990 barrels of oil per day are hedged at an average WTI price of $US 74.98. In 2016, Eagle has 1,000 barrels of oil per day hedged at an average WTI price of $US 59.16. In addition, Eagle has a natural gas hedge on 1,500 GJs per day at a fixed price of $CA 2.83 per GJ for the period of January 1, 2016 to December 31, 2016.

On October 1, 2015, the Trust entered into a fixed price financial swap on 1,000 barrels per day of oil fixing the differential between Edmonton light sweet and WTI at $US 3.65 per barrel for the period December 1, 2015 to December 31, 2016.

Segmented Operations

The Trust's operating activities relate solely to the exploration, development and production of petroleum and natural gas resources in the United States and Canada. Costs incurred in the Corporate segment relate to the Trust's hedging program and other expenses incurred in overall financing and administration of the Trust.

United States

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Production						
Oil (bbls/d)	2,151	2,342	(8)	1,900	2,539	(25)
Natural gas (mcf/d)	318	1,520	(79)	277	1,539	(82)
Natural gas liquids (bbls/d)	60	263	(77)	57	274	(79)
Oil equivalent sales volumes (boe/d @ 6:1)	**2,264**	2,859	(21)	**2,003**	3,069	(35)
Activity						
Capital expenditures ($000's)	1,554	2,206	(32)	11,130	20,154	(45)
Wells drilled (rig -released)						
Gross	-	1.0	(100)	6.0	5.0	20
Net	-	0.8	(100)	6.0	4.4	35
Wells brought on-stream						
Gross	1.0	1.0	-	5.0	5.0	-
Net	1.0	0.8	25	5.0	4.4	13

$000's	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Sales before royalties	12,022	23,566	(49)	32,993	78,341	(58)
Royalties	(3,420)	(6,423)	(47)	(9,409)	(21,403)	(56)
Operating expenses	(3,481)	(4,148)	(16)	(10,076)	(12,705)	(21)
Transportation and marketing expenses	(26)	(164)	(84)	(88)	(553)	(84)
Field netback	**5,095**	12,831	(60)	**13,420**	43,680	(69)
($/boe)						
Sales before royalties	57.72	89.61	(36)	60.33	93.49	(35)
Royalties	(16.42)	(24.42)	(33)	(17.20)	(25.54)	(33)
Operating expenses	(16.71)	(15.77)	6	(18.42)	(15.16)	22
Transportation and marketing expenses	(0.12)	(0.62)	(80)	(0.16)	(0.66)	(76)
Field netback	24.47	48.80	(50)	24.55	52.13	(53)

During the third quarter of 2015, capital expenditures were $1.6 million in the United States with average working interest sales volumes of 2,264 boe/d. To date, results from the capital program have met expectations and the Trust is on track to meet its 2015 guidance.

Revenue for the quarter was received primarily from two customers, Sunoco Logistics Partners L.P. ("Sunoco") and Plains Marketing L.P. ("Plains"), with revenue received amounting to $8.8 million (49%) and $2.4 million (13%) respectively. For the third quarter of 2014, $17.0 million (77%) of revenue was received from Sunoco and $3.4 million (14%) from Plains.

Salt Flat Properties, Texas

At Salt Flat, all three drills are on line and performing above expectations.

Hardeman Properties, Texas and Oklahoma

At Hardeman, the new salt water disposal facility was put into service and is expected to reduce operating expenses in the southern part of the Hardeman area. Electrical infrastructure is being expanded to include additional producing wells to gain further efficiencies. Two additional wells are planned to be drilled in the fourth quarter of 2015.

Canada

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Production						
Oil (bbls/d)	1,212	-		1,159	-	
Natural gas (mcf/d)	700	-		287	-	
Natural gas liquids (bbls/d)	14	-		5	-	
Oil equivalent sales volumes (boe/d @ 6:1)	**1,343**	**-**		**1,211**	-	
Activity						
Capital expenditures ($000's)	(150)	-		17	-	

$000's	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	%	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	%
Sales before royalties	5,866	-		15,097	-	
Royalties	(1,040)	-		(2,163)	-	
Operating expenses	(2,388)	-		(6,392)	-	
Transportation and marketing expenses	(579)	-		(1,550)	-	
Field netback	**1,859**	**-**		**4,992**	-	
($/boe)		-			-	
Sales before royalties	47.46	-		45.66	-	
Royalties	(8.42)	-		(6.54)	-	
Operating expenses	(19.32)	-		(19.33)	-	
Transportation and marketing expenses	(4.68)	-		(4.69)	-	
Field netback	15.04	**-**		15.10	-	

During the third quarter of 2015, capital expenditures were $150,000 in Canada with average working interest sales volumes of 1,343 boe/d. Revenue for the third quarter was received primarily from Eagle's operated partner at Dixonville in the amount of $5.0 million. Beginning September 1, 2015, Eagle began to take in kind its production in Dixonville.

Dixonville Properties, Alberta

Effective January 1, 2015, a subsidiary of the Trust acquired a 50% non-operated working interest in the Dixonville Montney "C" oil pool, located in the Peace River region of Alberta, Canada. Eagle's 2015 Dixonville budget will be limited to maintenance capital.

Capital expenditures for the third quarter were $90,000 for maintenance capital.

Twining Properties, Alberta

On August 20, 2015, the Trust acquired Privateco, which owned an average 80% working interest in the Twining field, in Alberta, located in one of the largest Pekisko oil pools in the Western Canadian Sedimentary Basin (refer to the "Acquisition" section of this MD&A). The Twining properties have been integrated into Eagle's operations and Eagle has commenced production improvements with $60,000 having been spent on well workovers during the third quarter. There is no drilling planned for 2015 as the two wells previously slated to be drilled in 2015 are now expected to be drilled in 2016.

Corporate

$000's	**Three Months Ended September 30, 2015**	**Three Months Ended September 30, 2014**	**%**	**Nine Months Ended September 30, 2015**	**Nine Months Ended September 30, 2014**	**%**
Administrative expenses	(2,880)	(4,212)	(32)	(7,684)	(9,776)	(21)
Risk management gain (loss) - realized	3,774	6,866	(45)	16,696	(476)	(3,604)
Cash settled award payments	(57)	(166)	(66)	(171)	(528)	(68)
Finance expense	(459)	(325)	41	(1,482)	(2,002)	(26)
Realized foreign exchange gain (loss)	(3)	(27)	(89)	(226)	(82)	174
Funds flow from operations	**374**	2,136	(83)	**7,133**	(12,864)	(155)

For the three and nine month periods ended September 30, 2015, corporate administrative expenses decreased when compared to the prior year's comparative periods due to the one time transaction costs associated with the Trust's internal reorganization in the second quarter of 2014, as well as one time transaction costs in the third quarter of 2014 associated with the sale of the Permian assets. This decrease was offset by transaction costs of approximately $0.9 million in the third quarter of 2015 associated with the acquisition of the Twining properties (refer to the "Acquisition" section of this MD&A).

Liquidity and Capital Resources

Generally, three sources of funding are available to the Trust: (1) internally generated funds flow from operations; (2) debt financing, when appropriate; and (3) the issuance of additional units, if available on favourable terms.

Refer to the "2015 Outlook" section of this MD&A for forecast funds flow from operations and expected debt to trailing cash flow ratio. This ratio may increase at certain times as a result of acquisitions, phasing of the capital program, or as a result of weaker commodity prices.

The Trust believes that its expected funds flow from operations and undrawn credit facility will be sufficient to fund its current and expected financial obligations. Refer to the "2015 Outlook" section for a discussion of the Trust's guidance and sensitivities to changes in commodity prices and production levels. Other than the items noted in the "Commitments" section of this MD&A, capital spending and distributions are discretionary.

Funds Flow from Operations

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

	Three Months Ended September 30, 2015		Three Months Ended September 30, 2014		**Nine Months Ended September 30, 2015**		Nine Months Ended September 30, 2014	
$000's		**/boe**		/boe		**/boe**		/boe
Field netback	6,955	20.96	12,832	48.80	18,412	20.98	43,680	52.13
Cash settled award payments	(57)	(0.17)	(166)	(0.62)	(171)	(0.19)	(528)	(0.62)
Administrative expenses	(2,880)	(8.68)	(4,212)	(16.02)	(7,684)	(8.76)	(9,776)	(11.67)
Realized risk management gain (loss)	3,774	11.37	(625)	(2.39)	16,696	19.03	(3,004)	(3.59)
Finance expense	(459)	(1.37)	(325)	(1.24)	(1,482)	(1.69)	(2,002)	(2.39)
Income tax recovery	1	-			45	0.05		
Realized foreign exchange gain (loss)[1]	(3)	(0.01)	(27)	(0.10)	(226)	(0.26)	(82)	(0.10)
Funds flow from operations	**7,331**	**22.09**	7,476	28.43	**25,590**	**29.16**	28,288	33.76

Note:

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

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

Credit Facility

At September 30, 2015, Eagle's credit facility was $US 85 million with a maturity date of May 26, 2017. Pricing remained the same and there were no material changes made to the covenants or conditions of the credit facility as outlined in the December 31, 2014 annual financial statements.

The semi-annual redetermination review of the credit facility was held on October 7, 2015, and Eagle's credit facility was reduced to $US 80 million. There were no changes to the pricing, covenants or conditions of the credit facility. The next semi-annual redetermination review of the credit facility will be held no later than May 15, 2016.

For the nine month period ended September 30, 2015, the interest rate on the revolving credit facility was approximately 3.3%.

As of September 30, 2015, the Trust had approximately $45.2 million ($US 33.9 million) of unused credit on its $113 million ($US 85 million) revolving credit facility, which is held indirectly through its subsidiaries with a syndicate of Canadian chartered banks.

Amounts drawn on the credit facility can be denominated in US or Canadian dollars and be used for activities in either the United States or Canada. Borrowing on the revolving credit facility is by way of LIBOR and base rate loans for amounts drawn in US funds and banker's acceptance and prime rate loans for amounts drawn in Canadian funds and are subject to a pricing grid based upon the debt to four quarter trailing EBITDAX ratio (to a maximum 3:1). Eagle must also maintain a minimum four quarter trailing interest expense coverage ratio (being the interest expense for the trailing four quarters divided into the four quarter trailing EBITDAX) of not less than 3:1. "Interest expense" is defined in the credit facility as the sum of (a) all interest, premium payments, debt discount, fees, charges and related expenses in connection with debt (including capitalized interest and amortization of debt discount) to the extent treated as interest in accordance with IFRS, and (b) the portion of rent expense with respect to such period under capital leases that is treated as interest in accordance with IFRS.

At September 30, 2015, there were no covenant violations under, or in connection with, the credit facility and the actual distributable cash flow of approximately $35 million for the previous four quarters exceeded cash distributions for the previous four quarters by approximately $17.0 million.

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

Working Capital

At September 30, 2015, the Trust had cash on hand of $4.6 million, a working capital surplus, excluding non-cash unit-based payments and non-cash risk management asset, of approximately $2.1 million and $68 million drawn on its bank credit facility described above.

Unitholders' Equity

Commencing with the January 2015 distribution paid on February 23, 2015, the Trust suspended the regular distribution reinvestment component of the DRIP. No material Trust capital issuances occurred during the third quarter.

For the one year period commencing January 21, 2015 and ending January 20, 2016, the Trust initiated a Normal Course Issuer Bid ("NCIB"). The Trust may purchase for cancellation up to 2,852,829 units, representing 10% of its public float as at January 16, 2015. Purchases will be made through an automatic unit purchase plan with a broker in order to facilitate the repurchase of the Trust's units under its NCIB. The purchase of units will be at the prevailing market price of the units at the time of purchase and will be subject to a maximum daily purchase volume of 30,732 units (being 25% of the average daily trading volume of the Trust's units from July 1, 2014 to December 31, 2014), except as otherwise permitted under the NCIB rules of the Toronto Stock Exchange.

During the third quarter of 2015, the Trust had purchased for cancellation 68,000 units at a weighted average market price of $2.15 per unit. For the nine months ended September, 2015, the Trust purchased for cancellation 160,300 units at a weighted average market price of $2.45 per unit.

A summary of the number of units issued, proceeds resulting from the issuance of units, average price per unit resulting from the DRIP and units purchased and cancelled under the NCIB at September 30, 2015, December 31, 2014 and September 30, 2014 is as follows:

	Nine Months Ended September 30, 2015	**Year Ended December 31, 2014**	**Nine Months Ended September 30, 2014**
Number of units issued under the DRIP	36,552	2,868,203	2,671,648
Fair market value of units issued under the DRIP ($000's)	-	2,319	2,381
Net proceeds from issuance of Trust capital ($000's)	67	17,421	16,612
Average price per unit issued under the DRIP	1.84	6.07	6.23
Number of trust units cancelled pursuant to the NCIB	160,300	-	-
Reduction of Trust capital pursuant to the NCIB ($000's)	1,548	-	-
Average price per unit cancelled pursuant to the NCIB	2.45	-	-

Management may also seek to issue additional units in the future to provide sufficient capital to fund growth, including acquisition opportunities.

Distributions and Outstanding Unit Data

The Trust pays monthly distributions to unitholders at the discretion of the Board of Directors. Commencing with the distribution paid on January 23, 2015, the Trust took action to protect its balance sheet in light of current and expected commodity prices by lowering its monthly distribution from $0.0875 to $0.03 per unit per month. Cash distributions paid in the third quarter (for the June, July and August, 2015 record dates) totaled approximately $3.2 million.

At September 30, 2015, the Trust had issued 34,893,364 units (December 31, 2014 – 35,017,112; September 30, 2014 – 34,820,557).

As at the date of this MD&A, 34,941,364 units are issued and 3,229,750 options are outstanding (with a weighted average exercise price of $5.64).

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

$000’s	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Earnings (loss) for the period	(51,786)	8,104	(52,850)	(12,836)
Cash distributions paid	(3,143)	(8,941)	(9,444)	(26,132)
Excess (shortfall) of earnings over cash distributions paid	**(54,929)**	(837)	**(62,294)**	(38,968)
Funds flow from operations[1]	7,331	7,476	25,590	28,288
Changes in operating working capital	2,170	1,304	(4,136)	1,710
Net cash provided by operating activities	9,501	8,780	21,454	29,998
Cash distributions paid	(3,143)	(8,941)	(9,426)	(26,132)
Excess (shortfall) of net cash provided by operating activities over cash distributions paid	**6,358**	(161)	**12,028**	3,866

Note:

(1) See “Non-IFRS financial measures”.

For the three and nine month periods ended September 30, 2015 and 2014, cash distributions paid exceeded earnings (loss) for the period due to the non-cash items that are deducted or added in determining earnings (loss) for the period. Earnings (loss) often does not move directionally or by the same amount as movements in net cash provided by operating activities. This is primarily due to items of a non-cash nature which factor into the calculation of earnings (loss), and are required to be fair-valued at each period end. Examples of non-cash items include depreciation, depletion and amortization, impairment, unit-based compensation, foreign exchange impact on intercompany loans, and unrealized risk management gains and losses, all of which have no impact on cash available to pay distributions.

For the three and nine month periods ended September 30, 2015 and 2014, net cash provided by operating activities exceeded cash distributions paid.

Capital Expenditures

Capital expenditures during the three and nine month periods ended September 30, 2015 and September 30, 2014 were as follows:

$000’s	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Exploration and evaluation[1]	-	-	-	16
Acquisition	27,337	-	27,337	5,409
Disposition - Permian	-	(150,147)	-	(150,147)
Intangible drilling and completions	935	1,748	7,677	15,302
Seismic	-	337	-	3,284
Well equipment and facilities	708	92	3,410	1,501
Other	56	29	60	51
	29,036	(147,941)	**38,484**	(124,584)

Note:

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

Refer to the “Segmented operations” section and “Acquisition” section of this MD&A for a discussion of these capital expenditures.

Commitments

The Trust has committed to future payments as follows:

$000's	Total	Less than 1 year	1 – 3 years
Operating leases (1) (2) (3)	2,442	877	1,565
Total contractual obligations	**2,442**	**877**	**1,565**

Notes:

(1) On January 1, 2013, the Trust entered into a lease for office space in Calgary which has an approximate 61 month term from January 8, 2013 to February 7, 2018. Future minimum lease payments during the term of the lease approximate $2.4 million and include a leasehold improvements allowance up to $0.3 million, with 28 months and approximately $1.1 million remaining at September 30, 2015.

(2) On August 20, 2015, concurrent with the closing of the acquisition of a private company, the Trust assumed an obligation for the private company's office lease. The term of the lease is from March 1, 2011 to February 28, 2017. Future minimum lease payments during the term of the lease approximate $1.4 million, with 17 months and approximately $0.4 million remaining at September 30, 2015.

(3) The Trust entered into a lease in Houston on April 1, 2011, which originally had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease was extended for an additional 63 month period from October 1, 2013 to December 31, 2017 and the premise space was expanded to incorporate additional square footage. Future minimum lease payments during the term of the lease include a leasehold improvement allowance of $US 0.1 million and approximate $US 0.9 million, with 27 months and approximately $US 0.66 million remaining at September 30, 2015. In $CA the remaining future minimum lease payments approximate $0.9 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.34.

Non-IFRS Financial Measures

Statements throughout this MD&A make reference to the terms "funds flow from operations", "field netback", "corporate payout ratio" and "EBITDAX", which are non-IFRS financial measures that do not have a standardized meaning prescribed by IFRS and may not be comparable to similar measures presented by other issuers. Management believes that these terms provide useful information to investors and management since such measures reflect the quality of production, the level of profitability, the ability to drive growth through the funding of future capital expenditures and the sustainability of distributions to unitholders.

"Funds flow from operations" is calculated before changes in non-cash working capital and abandonment expenditures. Management considers funds flow from operations to be a key measure as it demonstrates Eagle's ability to generate the cash necessary to pay distributions, repay debt, fund decommissioning liabilities and make capital investments. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds flow from operations provides a useful measure of Eagle's ability to generate cash that is not subject to short-term movements in non-cash operating working capital. Refer to the table below in the management's discussion and analysis under "Non-IFRS Financial Measures" for a reconciliation of funds flow from operations to earnings (loss).

"**Field netback**" is calculated by subtracting royalties and operating costs from revenues.

"Corporate payout ratio" is calculated by dividing capital expenditures (excluding acquisition capital) plus unitholder distributions by funds flow from operations.

"EBITDAX", as defined in the Trust's credit facility, means:

(a) net income for such period of determination; plus

(b) to the extent deducted in determining net income, interest expense, charges against income for foreign, federal, state, and local taxes, depreciation, amortization, depletion and exploration expense and other non-recurring expenses that do not represent a cash item in such period or any future period; minus

(c) extraordinary or non-recurring gains for such period; minus

(d) any gain realized upon an asset disposition of any assets (other than in the ordinary course of business); minus

(e) non-cash gains, losses or adjustments under Financial Accounting Standards Board (FASB) Statement 133 as a result of changes in the fair market value of derivatives; minus

(f) federal, state, local and foreign income tax credits.

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

$000’s	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Earnings (loss)	(51,786)	8,104	(52,850)	(12,836)
Add back (deduct) items not involving cash				
Unit-based compensation – non-cash portion	(1,282)	(2,278)	(528)	(5,414)
Unrealized risk management loss (gain)	(3,808)	(7,491)	8,359	(2,528)
Depreciation, depletion and amortization	8,173	9,054	20,376	48,692
Impairment	61,281	-	61,281	-
Finance expense	194	87	627	374
Foreign exchange loss (gain) on intercompany loan	(5,441)	-	(11,675)	-
Funds flow from operations	7,331	7,476	25,590	28,288
Add back (deduct items not directly related to field operations				
Finance expense (cash portion)	459	27	1,482	82
Realized foreign exchange loss (gain)	3	325	226	2,002
Risk management (gain) loss-realized	(3,774)	625	(16,696)	3,004
Administrative expenses	2,880	4,212	7,684	9,776
Income tax recovery	(1)	-	(45)	0
Cash settled award payments	57	166	171	528
Field netback	**6,955**	12,831	**18,412**	43,680

No Change in Internal Controls over Financial Reporting and Disclosure Controls and Procedures during the Period July 1, 2015 to September 30, 2015

During the period beginning on July 1, 2015 through September 30, 2015, there was no change in the Trust’s internal controls over financial reporting and disclosure controls and procedures that has materially affected, or is reasonably likely to materially affect, the Trust’s internal controls over financial reporting and disclosure controls and procedures. It should be noted, that 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.

Critical Accounting Estimates

There have been no changes to the Trust’s critical accounting estimates and judgments in the third quarter of 2015. Further information about the Trust’s critical accounting estimates and judgments can be found in the notes to the annual audited consolidated financial statements and MD&A for the year ended December 31, 2014.

Accounting Standards and Interpretations

The accounting policies followed in these condensed consolidated interim financial statements are consistent with those of the previous financial year.

There were no new or amended standards issued during the three and nine months ended September 30, 2015 which are applicable to the Trust in future periods. Additional adjustments to the Trust’s accounting policies may be required upon completion of a separate IASB framework for extractive industries.

Note about Forward-Looking Statements

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 2015 capital budget and specific uses;
- the Trust's expectations regarding its 2015 full year average working interest production, operating costs and field netbacks;
- the Trust's expectations regarding its 2015 funds flow from operations, corporate payout ratio and debt to trailing cash flow, and sensitivities of these metrics to production rates and commodity prices;
- forecast corporate decline rates, sustaining capital and future development costs associated with reserves;
- anticipated crude oil, natural gas liquids and natural gas production levels;
- estimates of discovered oil initially-in-place and reserves, and drilling locations of Privateco;
- the Trust's expectations regarding distributions; and
- the Trust's belief that its expected funds flow from operations and undrawn credit facility will be sufficient to fund its current and expected financial obligations.

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

- future oil, natural gas liquid and natural gas prices and weighting;
- future currency exchange rates;
- the regulatory framework governing taxes in the US and Canada and the Trust's status as a "mutual fund trust" and a "SIFT trust";
- future production levels;
- future recoverability of reserves;
- future distribution levels;
- future capital expenditures and the ability of the Trust to obtain financing on acceptable terms for its capital projects and future acquisitions;
- the Trust's 2015 capital budget, which is subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions and regulations;
- not including capital required to pursue future acquisitions in the forecasted capital expenditures;
- estimates of anticipated future production, which is based on the proposed drilling program with a success rate that, in turn, is based upon historical drilling success and an evaluation of the particular wells to be drilled; and
- projected operating costs, which are based on historical information and anticipated changes 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 those in the AIF:

- volatility of oil, natural gas liquid, and natural gas prices;
- commodity supply and demand;
- fluctuations in currency exchange 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 AIF under the heading "Risk Factors".

As a result of these risks, actual performance and financial results in 2015 may differ materially from any projections of future performance or results expressed or implied by these forward-looking statements. The Trust's production rates, operating costs, field netbacks, drilling program, 2015 capital budget, funds flow from operations, and distributions are subject to change in light of ongoing results, prevailing economic circumstances, obtaining regulatory approvals, commodity prices and industry conditions and regulations. New factors emerge from time to time, and it is not possible for management to predict all of these factors or to assess, in advance, the impact of each such factor on the Trust's business, or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

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.

Advisory Regarding Oil and Gas Measures and Estimates

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

The estimates of reserves provided in this MD&A are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided. The reserves estimates were prepared by Privateco's independent reserves evaluator. The effective date of the reserves estimates was March 31, 2015.

This MD&A contains references to estimates of oil classified as discovered oil initially-in-place ("DOIIP") which are not, and should not be confused with, oil reserves. DOIIP is defined in the Canadian Oil and Gas Evaluation Handbook as the quantity of oil that is estimated to be in place within a known accumulation prior to production. The estimate of DOIIP in this MD&A has been prepared by Eagle's internal reserves evaluator. The effective date of the DOIIP estimate is March 31, 2015. The estimate of DOIIP is divided into recoverable and unrecoverable portions, with the estimated future recoverable portion classified as "reserves" and "contingent resources" and the remainder classified as at the evaluation date as "unrecoverable". The accuracy of resource estimates is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. The size of the resource estimate could be positively impacted, potentially in a material amount, if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir is larger than what is currently estimated based on the interpretation of seismic and well control. The size of the resource estimate could be negatively impacted, potentially in a material amount if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir are less than what is currently estimated based on the interpretation of the seismic and well control. Estimates of DOIIP described in this MD&A are estimates only; the actual resources may be higher or lower than those calculated by Eagle's internal reserves evaluator. There is uncertainty that it will be commercially viable to produce any portion of the resources.

Eagle Energy Trust

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

For the three and nine months ended September 30, 2015 and September 30, 2014

Eagle Energy Trust

Condensed Consolidated Interim Balance Sheets

(Thousands of Canadian dollars) (unaudited)

	Note	**September 30, 2015**	December 31, 2014
ASSETS			
Current assets			
Cash		4,581	11,127
Trade and other receivables		7,843	6,669
Prepaid expenses		1,436	530
Risk management asset	3	8,002	14,919
		21,862	**33,245**
Non-current assets			
Risk management asset	3	311	-
Oil and gas properties	4, 11	205,755	222,939
Property, plant and equipment		201	219
Other intangible assets		831	769
		207,098	**223,927**
Total Assets		**228,960**	**257,172**
LIABILITIES			
Current liabilities			
Trade and other payables		6,178	8,316
Distributions payable		1,047	1,068
Unit-based payments	6	808	1,336
		8,033	**10,720**
Non-current liabilities			
Debt	12	68,212	47,200
Deferred income tax	9	-	-
Decommissioning liability	13	23,104	10,347
		91,316	**57,547**
Total Liabilities		**99,349**	**68,267**
UNITHOLDERS' EQUITY			
Trust capital	14	315,669	317,150
Currency reserves		34,694	29,494
Accumulated loss		(95,011)	(41,424)
Accumulated cash distributions	15	(125,741)	(116,315)
Total Unitholders' Equity		**129,611**	**188,905**
Total Liabilities and Unitholders' Equity		**228,960**	**257,172**

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

See note 16 “Commitments” and note 17 “Subsequent events”.

Eagle Energy Trust

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

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

	Note	**Three Months Ended September 30, 2015**	Three Months Ended September 30, 2014	**Nine Months Ended September 30, 2015**	Nine Months Ended September 30, 2014
Revenue		17,888	23,566	48,090	78,341
Royalties		(4,460)	(6,423)	(11,572)	(21,403)
		13,428	**17,143**	**36,518**	**56,938**
Operating expenses		5,868	4,148	16,468	12,705
Transportation and marketing expenses		605	164	1,638	553
Administrative expenses		2,880	4,212	7,684	9,776
Impairment	7	61,281	(44)	61,281	20,082
Depreciation, depletion and amortization		8,173	9,098	20,376	28,610
Operating loss		**(65,379)**	**(435)**	**(70,929)**	**(14,788)**
Unit based compensation expense (recovery)	6	(1,225)	(2,112)	(357)	(4,886)
Finance expense	8	653	412	2,109	2,376
Risk management loss (gain)	3	(7,582)	(6,866)	(8,337)	476
Foreign exchange loss (gain) net		3	27	226	82
Foreign exchange loss (gain) on intercompany loan		(5,441)	**-**	(11,675)	**-**
Earnings (loss) before taxes		**(51,787)**	**8,104**	**(52,895)**	**(12,836)**
			-		-
Income tax recovery	9	(1)	-	(45)	-
Earnings (loss)		**(51,786)**	**8,104**	**(52,850)**	**(12,836)**
Foreign currency translation gain (loss)		1,332	12,039	5,200	12,218
Comprehensive earnings (loss)		**(50,454)**	**20,143**	**(47,650)**	**(618)**
Earning (loss) per unit	10				
Basic		**(1.48)**	**0.24**	**(1.51)**	**(0.39)**
Diluted		**(1.48)**	**0.18**	**(1.51)**	**(0.44)**

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

Eagle Energy Trust

Condensed Consolidated Interim Statements of Changes in Unitholders' Equity

For the nine months ended September 30, 2015 and year ended December 31, 2014

(Thousands of Canadian dollars) (unaudited)

	Note	Number of trust units (000's)	Trust capital	Currency reserve	Accumulated earnings/ (loss)	Accumulated cash distributions	Deficit	**Total Unitholders' Equity**
Balance at December 31, 2013		**32,149**	**297,447**	**11,100**	**6,604**	**(80,454)**	**(73,850)**	**234,697**
Loss	10	-	-	-	(12,836)	-	(12,836)	(12,836)
Foreign currency translation gain		-	-	12,218	-	-	-	12,218
Total comprehensive earnings (loss)		-	-	12,218	(12,836)	-	(12,836)	(618)
Issuance of trust capital		2,672	19,010	-	-	-	-	19,010
Trust unit issuance costs		-	(37)	-	-	-	-	(37)
Unitholder distributions		-	-	-	-	(28,746)	(28,746)	(28,746)
			18,973	-	-	(28,746)	(28,746)	(9,773)
Balance at September 30, 2014		**34,821**	**316,420**	**23,318**	**(6,232)**	**(109,200)**	**(115,432)**	**224,306**
Balance at December 31, 2014		**35,017**	**317,150**	**29,494**	**(41,424)**	**(116,315)**	**(157,739)**	**188,905**
Loss	10	-	-	-	(52,850)	-	(52,850)	(52,850)
Foreign currency translation gain		-	-	5,200	-	-	-	5,200
Total comprehensive earnings (loss)		-	-	5,200	(52,850)	-	(52,850)	(47,650)
Issuance of trust capital	14	36	67	-	-	-	-	67
Cancellation of trust capital pursuant to NCIB	14	(160)	(1,548)	-	1,152	-	1,152	(396)
Unitholder distributions	15	-	-	-	-	(9,426)	(9,426)	(9,426)
Adjustment to retained earnings related to the acquisition		-	-	-	(1,889)	-	(1,889)	(1,889)
		(124)	(1,481)	-	(737)	(9,426)	(10,164)	(11,644)
Balance at September 30, 2015		**34,893**	**315,669**	**34,694**	**(95,011)**	**(125,741)**	**(220,752)**	**129,611**

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

Eagle Energy Trust

Condensed Consolidated Interim Cash Flow Statements

(Thousands of Canadian dollars) (unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	**Nine Months Ended September 30, 2015**	Nine Months Ended September 30, 2014
Cash flows from operating activities				
Earnings (Loss)	(51,786)	8,104	(52,850)	(12,836)
Adjustments for non-cash items:				
Impairment	61,281	(44)	61,281	20,082
Depreciation, depletion and amortization	8,173	9,098	20,376	28,610
Unit-based compensation – non-cash portion	(1,282)	(2,278)	(528)	(5,414)
Unrealized risk management loss (gain)	(3,808)	(7,491)	8,359	(2,528)
Foreign exchange loss (gain) on intercompany loan	(5,441)	-	(11,675)	-
Finance expense	194	87	627	374
	7,331	7,476	25,590	28,288
Changes in working capital:				
Trade and other receivables	1,958	3,237	(390)	2,875
Prepaid expenses	(1,149)	(68)	(838)	(35)
Trade and other payables	1,361	(1,866)	(2,908)	(1,130)
	2,170	1,303	(4,136)	1,710
Net cash generated by operating activities	**9,501**	**8,779**	**21,454**	**29,998**
Cash flows from investing activities				
Exploration and evaluation	-	-	-	(16)
Oil and gas properties	(1,643)	(2,177)	(11,087)	(20,087)
Property, plant and equipment	(56)	(29)	(60)	(51)
Acquisition of oil and gas assets	(27,337)	-	(27,337)	(5,409)
Disposition of oil and gas assets	-	150,147	-	150,147
Change in non-cash working capital	(114)	505	(60)	1,233
Net cash generated by (used in) investing activities	**(29,150)**	**148,446**	**(38,544)**	**125,817**
Cash flows from financing activities				
Debt	28,212	(84,700)	21,012	(78,121)
Proceeds from issuance of units	-	6,039	67	16,648
Purchase of trust units for cancellation	(143)	-	(393)	(37)
Trust unit issue costs	(5)	-	(5)	-
Cash distributions to unitholders	(3,143)	(8,941)	(9,426)	(26,132)
Deferred financing charges	(49)	(5)	(414)	(302)
Net cash generated by (used in) financing activities	**24,872**	**(87,607)**	**10,841**	**(87,944)**
Net increase (decrease) in cash and cash equivalents	**5,223**	**69,618**	**(6,249)**	**67,871**
Effects of exchange rates on cash and cash equivalents	(816)	(83)	(297)	229
Cash at beginning of the period	174	-	11,127	1,435
Cash at end of the period	**4,581**	**69,535**	**4,581**	**69,535**

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

Eagle Energy Trust

Notes to Condensed Consolidated Interim Financial Statements (unaudited)

For the three months and nine months ended September 30, 2015 and September 30, 2014
(in Canadian dollars)

1. Reporting Entity / Structure of the Trust

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

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

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

The strategy of the Trust is to invest in operating subsidiaries that will acquire on-shore petroleum reserves and production in certain regions of Canada and 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 the indirectly owned subsidiaries of the Trust, Eagle Hydrocarbons Inc., Eagle Energy Canada Inc. and Eagle-Coda Petroleum Inc.

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

2.1. Basis of Preparation

The foreign exchange rate at September 30, 2015 was $US 1.00 equal to $CA 1.34 (December 31, 2014 - $US 1.00 equal to $CA 1.16), and the average foreign exchange rate for the nine months ended September 30, 2015 was $US 1.00 equal to $CA 1.26 (for the nine months ended September 30, 2014 - $US 1.00 equal to $CA 1.09).

Basis of Accounting

The condensed consolidated interim financial statements were authorized for issue in accordance with a resolution of the Board of Directors made on November 5, 2015.

These condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including IAS 34, interim Financial Reporting and have been prepared following the same accounting policies as the annual audited IFRS consolidated financial statements for the year ended December 31, 2014, except for income tax expense for an interim period which is based on an estimated average annual effective income tax rate. The condensed consolidated interim financial statements should be read in conjunction with the annual audited, consolidated financial statements for the year ended December 31, 2014, which have been prepared in accordance with IFRS as issued by the IASB.

2.2. Changes in Accounting Policy and Disclosures

The accounting policies followed in these condensed consolidated interim financial statements are consistent with those of the previous financial year.

Accounting Pronouncements not yet Adopted

IFRS 9, Financial Instruments, replaces International Accounting Standard 39, Financial Instruments: Recognition and Measurement. IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if

IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Trust is currently evaluating the impact of adopting IFRS 9 on the consolidated financial statements.

IFRS 15, Revenue from contracts with customers, replaces IAS 18 - Revenue and IAS 11 - Construction contracts and provides a new principle based model on revenue recognition to all contracts with customers. Mandatory adoption is effective for periods beginning on or after January 1, 2018. The Trust is currently evaluating the impact of adopting this standard on the consolidated financial statements.

A description of accounting policies and disclosures that were adopted by the Trust can be found in the notes to the annual consolidated financial statements for the year ended December 31, 2014. Additional adjustments to the Trust's accounting policies may be required upon completion of a separate IASB framework for extractive industries.

3. Financial Risk Management and Financial Instruments

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 changes in the Trust's exposure to each of the above risks since the year ended December 31, 2014.

Credit Risk

Credit risk is the risk of financial loss to the Trust if a customer, joint venture partner or counterparty to a financial instrument fails to meet its contractual obligations. It arises principally from the Trust's receivables from its product marketer and joint venture partners. The Trust limits its exposure, in this regard, by investing only in liquid securities and only with counterparties with a strong credit rating.

At September 30, 2015, there was no material change in credit risk compared to the December 31, 2014 year end.

Liquidity Risk

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

The semi-annual redetermination review of the credit facility was held on October 7, 2015 and Eagle's credit facility was reduced to $US 80 million. There were no changes to the pricing, covenants or conditions of the credit facility. The next semi-annual redetermination review of the credit facility will be held no later than May 15, 2016.

Market Risk

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

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

Commodity Price Risk

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

The Trust enters into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Trust does not apply hedge accounting for these contracts. The Trust's production is either sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price or by way of fixed term, fixed price marketing contracts.

Summary of Unrealized Risk Management Positions

As at September 30, 2015, the Trust has entered into the following financial contracts to mitigate the effects of fluctuating prices on a portion of its production:

	Volume	*Measure*	*Beginning*	*Term*	*Floor $US*	*Ceiling $US*	*Current fair value $000's $CA*	*Non-current fair value $000's $CA*
Oil Fixed Price								
NYMEX (i)	190	bbls/d	Jan-15	Dec-15	85.40	85.40	924	-
NYMEX (i)	400	bbls/d	Jul-15	Dec-15	87.90	87.90	2,069	-
NYMEX (i)	400	bbls/d	Oct-15	Dec-15	57.10	57.10	556	-
NYMEX (i)	500	bbls/d	Jan-16	Dec-16	65.00	65.00	3,584	252
NYMEX (i)	500	bbls/d	Jan-16	Dec-16	53.32	53.32	933	62
Gas Fixed Price								
CGPR ALT daily spot	1,500	GJs/day	Jan-16	Dec-16	2.83	2.83	(64)	(3)
Unrealized risk management asset							**8,002**	**311**

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

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

	Three Months Ended September 30, 2015			Three Months Ended September 30, 2014		
$000's	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)
Net effect - commodity	(3,774)	(3,808)	(7,582)	612	(7,569)	(6,957)
Net effect - foreign exchange	-	-	-	13	78	91
Net effect - risk management	**(3,774)**	**(3,808)**	**(7,582)**	**625**	**(7,491)**	**(6,866)**

	Nine Months Ended September 30, 2015			Nine Months Ended September 30, 2014		
$000's	Realized Loss (gain)	Unrealized loss (gain)	Total net loss (gain)	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)
Net effect - commodity	(16,696)	8,359	(8,337)	2,962	(2,609)	353
Net effect - foreign exchange	-	-	-	42	81	123
Net effect - risk management	**(16,696)**	**8,359**	**(8,337)**	**3,004**	**(2,528)**	**476**

Determination of Fair Values

The net fair value of Eagle's unrealized risk management positions at September 30, 2015, is an asset of $8.3 million (December 31, 2014 - $14.9 million asset). The carrying value of the Trust's risk management position has been calculated using both quoted prices in active markets and observable market-corroborated data consistent with a Level 2 valuation.

The fair values of cash, trade and other receivables, trade and other payables and distributions payable approximate their carrying amount due to the short-term maturity of those instruments.

Debt is a financial liability with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest rate method. The carrying value of the Trust's debt is equal to the fair value and the determination of the fair value of the debt is consistent with a Level 2 valuation.

4. Acquisition

On August 20, 2015, Eagle closed the acquisition of a private company by acquiring all of the issued and outstanding common shares of the private company for cash consideration of $0.06 per share and assumption of the acquired company's net debt. This acquisition has been accounted for as a business combination under IFRS 3.

To September 30, 2015, the assets acquired have contributed revenues of $0.9 million and operating income of $0.4 million. Had the acquisition closed on January 1, 2015, estimated contributed revenues would have been $10.0 million and estimated contributed operating income would have been $4.0 million to September 30, 2015.

Net assets acquired ($000's)	
Oil and gas assets	30,524
Decommissioning liability	(3,187)
Working capital	(4,951)
Bank debt	(17,855)
Net asset value	4,531
Cash	4,531
Consideration paid	4,531

5. Segmented Information

The Trust's operating activities relate solely to the exploration, development and production of petroleum and natural gas resources in the United States and Canada. Costs incurred in the Corporate segment relate to the Trust's hedging program, public company, and other expenses incurred in overall financing and administration of the Trust.

Eagle's management reviews financial performance by assessing the funds flow from operations of each operating segment. Funds flow from operations is measured before changes in non-cash operating working capital and provides a measure of each segment's ability to generate cash necessary to fund distributions, capital expenditures and asset retirement obligations.

The segmented information below makes reference to the term "funds flow from operations" which is a non-IFRS financial measure that does not have a standardized meaning prescribed by IFRS, and may not be comparable to similar measures presented by other issuers.

Details of the Trust's reportable segments are as follows:

	Three Months Ended September 30, 2015			
$000's	**Canada**	**United States**	**Corporate**	**Total**
Capital expenditures	**150**	**1,554**	**(5)**	**1,699**
Revenue	5,866	12,022	-	17,888
Royalties	(1,040)	(3,420)	-	(4,460)
Revenue net of royalties	4,826	8,602	-	13,428
Operating expenses	2,388	3,480	-	5,868
Transportation and marketing expenses	579	26	-	605
	1,859	5,096	-	6,955
Administrative expenses	1,114	1,618	148	2,880
Cash settled award payments	-	-	57	57
Risk management gain - realized	-	-	(3,774)	(3,774)
Finance expense (cash portion)	-	-	459	459
Income tax recovery	-	-	(1)	(1)
Realized foreign exchange gain	-	-	3	3
Funds flow from operations	**745**	**3,478**	**3,108**	**7,331**

	Nine Months Ended September 30, 2015			
$000's	**Canada**	**United States**	**Corporate**	**Total**
Capital expenditures	17	11,130	-	11,147
Total assets	**147,947**	**72,700**	**8,312**	**228,959**
Revenue	15,097	32,993	-	48,090
Royalties	(2,163)	(9,409)	-	(11,572)
Revenue net of royalties	12,934	23,584	-	36,518
Operating expenses	6,392	10,076	-	16,468
Transportation and marketing expenses	1,550	88	-	1,638
	4,992	**13,420**	**-**	**18,412**
Administrative expenses	1,263	5,709	712	7,684
Cash settled award payments	-	-	171	171
Risk management gain - realized	-	-	(16,696)	(16,696)
Finance expense (cash portion)	-	-	1,482	1,482
Income tax recovery	-	(45)		(45)
Realized foreign exchange loss	-		226	226
Funds flow from operations	**3,729**	**7,756**	**14,105**	**25,590**

In the United States segment, revenue for the quarter was received primarily from two customers, Sunoco Logistics Partners L.P. ("Sunoco") and Plains Marketing L.P. ("Plains"), with revenue received amounting to $8.8 million (49%) and $2.4 million (13%) respectively. For the third quarter of 2014, $17.0 million (72%) of revenue was received from Sunoco and $3.4 million (14%) received from Plains. In the Canadian segment, revenue for the quarter was received primarily from Spyglass Recources Corp., the operating partner in Dixonville, in the amount of $5.0 million (28%).

Reconciliation of funds flow from operations to earnings (loss) for each reportable segment is as follows:

	Three Months Ended September 30, 2015			
$000's	Canada	United States	Corporate	Total
Funds flow from operations	**745**	**3,478**	**3,108**	**7,331**
Unit based compensation - non-cash portion	-	-	(1,282)	(1,282)
Risk management loss - unrealized	-	-	(3,808)	(3,808)
Depreciation, depletion and amortization	1,590	6,583	-	8,173
Impairment	24,741	36,540	-	61,281
Foreign exchange gain on intercompany loan	-	-	(5,441)	(5,441)
Finance expense (non-cash portion)	-	-	194	194
Earnings (loss)	**(25,586)**	**(39,645)**	**13,445**	**(51,786)**

	Nine Months Ended September 30, 2015			
$000's	Canada	United States	Corporate	Total
Funds flow from operations	**3,729**	**7,756**	**14,105**	**25,590**
Unit based compensation - non-cash portion	-	-	(528)	(528)
Risk management loss - unrealized	-	-	8,359	8,359
Depreciation, depletion and amortization	4,045	16,331	-	20,376
Impairment	24,741	36,540	-	61,281
Foreign exchange gain on intercompany loan	-	-	(11,675)	(11,675)
Finance expense (non-cash portion)	-	-	627	627
Earnings (loss)	**(25,057)**	**(45,115)**	**17,322**	**(52,850)**

Total assets of the Trust's reportable segments at September 30, 2015 were as follows:

	Nine Months-Ended September 30, 2015			
$000's	Canada	United States	Corporate	Total
Total Assets	**147,948**	**72,700**	**8,312**	**228,960**

The Canadian segment arose due to the acquisition of the Dixonville property on December 18, 2014, and the Twining property on August 20, 2015 (see note 4 "Acquisition). As the effective date of the Dixonville property acquisition was January 1, 2015, the Trust did not disclose its operating activities by segment at December 31, 2014.

6. Unit-based Payments

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

$000's	Note	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Restricted Unit Rights	6(a)	21	(162)	141	(637)
Unit Options	6(b)	(1,077)	(1,503)	(245)	(3,210)
Unit Rights	6(c)	(169)	(447)	(253)	(1,039)
Total unit-based compensation expense (recovery)		**(1,225)**	**(2,112)**	**(357)**	**(4,886)**

The following table reconciles the unit-based payments liability:

$000's	Note	September 30, 2015	December 31, 2014
Restricted Unit Rights	5(a)	30	61
Unit Options	5(b)	687	932
Unit Rights	5(c)	91	343
Total unit-based payments liability		**808**	1,336

Note (a)

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

For the nine months ended September 30, 2015, $170,760 has been paid to the RUR holders (year ended December 31, 2014 - $664,072, nine months ended September 30, 2014 – $498,076).

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

	Nine Months Ended September 30, 2015	Year Ended December 31, 2014	Nine Months Ended September 30, 2014
Balance, beginning of period	632,500	632,500	632,500
Issued	-	-	-
Forfeited	-	-	-
Balance, end of period	632,500	632,500	632,500
Number of RURs vested	632,500	632,500	632,500

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

	September 30, 2015	December 31, 2014	September 30, 2014
Fair value at the balance sheet date ($)	0.05	0.10	4.66
Volatility (%)	38	36	28
Life of RURs (years)	5.3	6.0	6.3
Risk-free interest rate (%)	1.50	1.83	2.17

A forfeiture rate of 5% was used, which is an estimated expected rate. The expected unit price volatility was calculated using the trading history of the Trust's units.

Note (b)

Unit Option Plan

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

	Nine Months Ended September 30, 2015		Year Ended December 31, 2014		Nine Months Ended September 30, 2014	
	Number of options	**Weighted average exercise price**	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding, beginning of period	3,431,750	5.94	3,126,750	7.05	3,126,750	7.05
Forfeited	(202,000)	6.45	(45,000)	5.51	(31,666)	6.19
Exercised	-	-	-	-	-	-
Granted	-	-	350,000	5.35	350,000	5.61
Outstanding at end of period	**3,229,750**	**5.64**	3,431,750	5.94	3,445,084	**6.20**
Exercisable at end of period	**2,520,760**	**5.67**	2,109,095	6.01	1,870,179	**6.22**

The range of exercise prices of the outstanding options is as follows at September 30, 2015:

	Weighted average exercise price	Weighted average contractual life (years)
$4.60 - $7.25	**5.64**	**6.80**

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

	September 30, 2015	December 31, 2014	September 30, 2014
Fair value - at balance sheet date ($)	0.25	0.37	1.67
Unit trading price - closing ($)	1.91	2.33	5.36
Exercise price – weighted average ($)	5.64	5.94	6.20
Volatility (%)	38	36	28
Option life – weighted average (years)	6.8	7.6	7.8
Risk-free interest rate (%)	1.50	1.83	2.17

A forfeiture rate of 5% was used, which is an estimated expected rate. The expected unit price volatility was calculated using the trading history of the Trust's units.

Note (c)

Unit Rights (URs) Plan

For the nine months ended September 30, 2015, $nil has been paid to the UR holders (year ended December 31, 2014 - $29,573, nine months ended September, 2014 - $29,573).

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

	Nine Months Ended September 30, 2015	Year Ended December 31, 2014	Nine Months Ended September 30, 2014
Balance, beginning of period	937,000	997,000	997,000
Issued	-	-	-
Forfeited	(283,500)	(60,000)	-
Balance, end of period	653,500	937,000	997,000
Number of unit rights vested	458,171	465,007	380,339

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

	September 30, 2015	December 31, 2014	September 30, 2014
Fair value at the balance sheet date($)	0.16	0.50	1.19
Volatility (%)	38	36	28
Life of PURs (years)	7.5	8.1	8.4
Risk-free interest rate (%)	1.50	1.83	2.17

A forfeiture rate of 5% was used, which is an estimated expected rate. The expected unit price volatility was calculated using the trading history of the Trust's units.

7. Impairment

United States - Salt Flat and Hardeman cash generating units

As a result of the current commodity price environment, the Trust's US assets were assessed for impairment at September 30, 2015. The impairment test used an expected cash flow approach based on internal cash flow estimates at September 30, 2015. A risk-adjusted discount rate of 10% was used for all areas and a WTI price of US$ 50.00 for the remainder of 2015, US$ 55.00 in 2016, US$ 61.20 in 2017, US$ 65.00 in 2018, US$ 69.00 in 2019, US$ 73.10 in 2020, US$ 77.30 in 2021, US$ 81.60 in 2022, US$ 86.20 in 2023, US$ 87.90 in 2024 and US$ 89.60 for the remainder. Based on the analysis, the Trust recorded an impairment provision of US$ 20.9 million in the Salt Flat cash generating unit and US$ 8.1 million in the Hardeman cash generating unit.

The calculation of the recoverable amount is sensitive to the discount rate and prices. A 2% increase in the discount rate would result in an after-tax impairment charge of an additional US$ 2.4 million impaired in Salt Flat, for a total impairment of US$ 23.3 million and an additional US$ 2.8 million in Hardeman for a total of US$ 10.9 million. A 5% decrease in prices would result in an after-tax impairment of an additional US$ 5.2 million (total US$ 26.1 million) in Salt Flat and US$ 3.4 million in Hardeman (total US$ 11.5 million).

Canada - Dixonville cash generating unit

At September 30, 2015, the Trust assessed its assets in the Dixonville area in Alberta for impairment, as a result of the current price environment. The impairment test used an expected cash flow approach based on internal cash flow estimates at September 30, 2015. A risk-adjusted discount rate of 11.6% was used and an Edmonton Par price of $49.90 for the remainder of 2015, $56.60 for 2016, $61.70 for 2017, $65.60 for 2018, $68.00 for 2019, $72.20 for 2020, $76.50 for 2021, $81.00 for 2022, $85.70 for 2023, $87.40 for 2024 and $89.00 for the remainder. Based on the analysis, the Trust recorded an impairment provision of $24.7 million in Dixonville at September 30, 2015.

The calculation of the recoverable amount is sensitive to the discount rate and prices. A 2% increase in the discount rate would result in an additional impairment of $12.8 million and a 5% decrease in prices would result in an after-tax impairment of an additional $6.2 million.

8. Finance Expense

$000's	**Three Months Ended September 30, 2015**	Three Months Ended September 30, 2014	**Nine Months Ended September 30, 2015**	Nine Months Ended September 30, 2014
Interest expense on debt	373	284	1,215	1,950
Amortization of deferred financing costs	110	72	414	312
Standby and bank fees	86	41	267	52
Accretion of decommissioning provision	84	15	213	62
Finance expense	**653**	412	2,109	2,376

9. Taxation

Reconciliation of Effective Tax Rate

The income tax provision differs from the amount that would have been expected if the reported (loss) earnings had been subject only to the statutory Canadian income tax rate of 26% (2014 - U.S. Federal and state combined rate of 35%) as follows:

$000's	**Three Months Ended September 30, 2015**	Three Months Ended September 30, 2014	**Nine Months Ended September 30, 2015**	Nine Months Ended September 30, 2014
(Loss) Earnings before taxation	(51,784)	8,104	(52,893)	(12,836)
Expected tax rate (%)	26	35	26	35
Expected income tax provision	(13,464)	2,836	(13,752)	(4,493)
Decrease (Increase) resulting from:				
Non-deductible items – permanent differences				
Administrative expenses of the Trust	36	168	182	416
Unit-based compensation	(244)	(739)	(48)	(1,710)
Foreign exchange loss (gain), net	(4,360)	(799)	(7,577)	(630)
Foreign tax rate differentials	(3,094)	-	(4,003)	-
Change in statutory rate(1)	(260)	-	(288)	-
Changes in temporary differences for which no amounts are recognized	22,030	21	27,245	10,641
Items deductible at the subsidiary level				
Interest on internal debt of subsidiary	(643)	(1,394)	(1,813)	(4,136)
Other	-	(93)	9	(88)
Total income tax recovery(2)	**(1)**	-	**(45)**	-

(1) The Alberta general corporate tax rate increased from 10% to 12%, substantively enacted as of June 20, 2015.
(2) Total income tax recovery relates to U.S. taxes paid in the previous year.

Deferred Tax Assets and Liabilities

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

$000's	**September 30, 2015**	December 31, 2014
Deferred tax (assets) liabilities		
Oil and gas properties	(19,652)	3,422
Non-capital losses	(54,233)	(32,216)
Net deferred tax (asset) liability – before valuation allowance	(73,885)	(28,794)
Unrecognized deferred tax asset	73,885	28,794
Net deferred tax (asset) liability	-	-

The U.S. and Canadian tax losses can be utilized for 20 years and start to expire in 2030 and 2035 respectively. Deferred tax assets have not been recognized in respect of these tax losses as there is not sufficient certainty regarding the future utilization.

10. Loss per Unit

$000's	**Three Months Ended September 30, 2015**	Three Months Ended September 30, 2014	**Nine Months Ended September 30, 2015**	Nine Months Ended September 30, 2014
Earnings (loss) attributable to unitholders - basic	(51,786)	8,104	(52,850)	(12,836)
Earnings (loss) attributable to unitholders - diluted	(51,786)	6,601	(52,850)	(13,111)
Weighted average number of units outstanding - basic	34,991	33,878	34,954	33,265
Weighted average number of units outstanding - diluted	34,991	37,479	34,954	36,755
Earnings (loss) per unit - basic	**(1.48)**	0.24	(1.51)	(0.39)
Earnings (loss) per unit - diluted	**(1.48)**	0.18	(1.51)	(0.44)

11. Oil and Gas Properties

$000's	Developed oil and gas assets	Production facilities and equipment	Impairment	Total
Cost				
At December 31, 2014	365,240	7,982	-	373,222
Additions	21,570	1,376	-	22,946
Acquisition, net	27,337	-		27,337
Effects of foreign exchange	38,591	1,202	-	39,793
At September 30, 2015	**452,738**	10,560	**-**	**463,298**
Accumulated depreciation, depletion and amortization				
At December 31, 2014	(89,354)	(4,242)	(56,687)	(150,283)
Impairment	-	-	(63,433)	(63,433)
Depreciation	(27,925)	(1,085)	7,776	(21,234)
Effects of foreign exchange	(13,433)	(638)	(8,522)	(22,593)
At September 30, 2015	**(130,712)**	**(5,965)**	**(120,867)**	**(257,543)**
Net book value				
At December 31, 2014	275,886	3,740	(56,687)	222,939
Net change for the period	46,141	855	(64,180)	(17,184)
At September 30, 2015	**322,027**	**4,595**	**(120,867)**	**205,755**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $123.1 million (December 31, 2014 - $42.9 million) were included in the depletion calculation.

12. Debt

At September 30, 2015, Eagle's credit facility was $US 85 million with a maturity date of May 26, 2017. Pricing remained the same and there were no material changes made to the covenants or conditions of the credit facility as outlined in the December 31, 2014 annual financial statements.

The semi-annual redetermination review of the credit facility was held on October 7, 2015, and Eagle's credit facility was reduced to $US 80 million. There were no changes to the pricing, covenants or conditions of the credit facility. The next semi-annual redetermination review of the credit facility will be held no later than May 15, 2016. See note 17 "Subsequent events".

For the nine month period ended September 30, 2015, the interest rate on the revolving credit facility was approximately 3.3%.

Under the credit facility, the Trust is required to satisfy certain customary affirmative and negative covenants (including financial covenants). Please refer to the 2014 annual financial statements for the criteria and definitions of the terms used in the debt covenants. The current quarter actual covenant calculations are substantially the same as the 2014 year end covenant calculations. The credit facility documentation provides for customary negative covenants which, among other things, limit the Trust in making distributions to its unitholders if any default, event of default or borrowing base deficiency has occurred and is continuing or would result from such distribution, or if the cash distributions made in the previous four quarters exceed the Available Distributable Cash Flow (as defined in the credit facility agreement) of the Trust for the previous four quarters. The credit facility documentation also includes other customary restrictive covenants including limitations on indebtedness, liens, contingent obligations, investments, dispositions, mergers, consolidations, liquidations and dissolutions. In addition, the Trust must maintain, as at the end of each fiscal quarter, a minimum current ratio (being the ratio of current assets plus the unused availability under the credit facility less cash subject to restriction and risk management assets and other assets resulting from a mark-to-market valuation is to current liabilities less the current portion of long-term debt and risk management liabilities and other liabilities resulting from a mark-to-market valuation) of not less than 1.00 to 1.00, a minimum four quarter trailing interest expense coverage ratio (being the four quarter trailing interest expense divided into the four quarter trailing EBITDAX) of not less than 3.00 to 1.00, and a maximum four quarter trailing debt to

EBITDAX ratio of 3.00 to 1.00.

Under the credit facility, "**EBITDAX**" means, calculated for such period:

(a) Net Income for such period of determination; plus

(b) to the extent deducted in determining Net Income, Interest Expense, charges against income for foreign, federal, state, and local taxes, depreciation, amortization, depletion and exploration expense and other non-recurring expenses that do not represent a cash item in such period or any future period; minus

(c) extraordinary or non-recurring gains for such period minus

(d) any gain realized upon an Asset Disposition of any assets (other than in the ordinary course of business); minus

(e) non-cash gains, losses or adjustments under Financial Accounting Standards Board (FASB) Statement 133 as a result of changes in the fair market value of derivatives; minus

(f) Federal, state, local and foreign income Tax credits;

At September 30, 2015, there were no covenant violations under or in connection with the credit facility and the actual distributable cash flow of approximately $35 million for the previous four quarters exceeded cash distributions for the previous four quarters by approximately $17.0 million.

At September 30, 2015, details of the Trust's credit facility are as follows:

$000's	$US	$CA
Authorized (revolving)	85,000	113,432
Less:		
Amounts drawn	51,114	68,212
Available	33,886	**45,220**

The exchange rate in effect at September 30, 2015 was $US 1.00 equal to $CA 1.34. The amount drawn on the credit facility at September 30, 2015 was denominated in Canadian funds.

At December 31, 2014, details of the Trust's credit facility are as follows:

$000's	$US	$CA
Authorized (revolving)	70,000	81,207
Less:		
Amounts drawn	40,686	47,200
Available	29,314	34,007

The exchange rate in effect at December 31, 2014 was $US 1.00 equal to $CA 1.16. The amount drawn on the credit facility at December 31, 2014 was denominated in Canadian funds.

13. Decommissioning Liability

$000's	**Nine Months Ended September 30, 2015**	Year Ended December 31, 2014
Beginning balance	10,347	3,036
Acquisition - see note 4 "Acquisition"	3,187	472
Additions	123	344
Change in estimate due to acquired properties	5,910	-
Other changes in estimates	2,913	7,981
Disposition	-	(1,189)
Abandonment expenditures	-	(212)
Accretion (unwinding of discount)	213	78
Effects of exchange rate	411	(163)
Ending balance	23,104	10,347

The decommissioning provision reflects the present value of internal estimates of future decommissioning costs of the Trust's net ownership position in oil and gas wells and related facilities at the relevant balance sheet date determined using local pricing conditions and requirements. The liability would be incurred over the life of the assets, with the majority after the year 2050. The timing of payments related to decommissioning provision 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 a 2.0% annual inflation rate), and discounted using a risk-free discount rate at September 30, 2015, of 1.45% for the Salt Flat properties, 2.41% for the Hardeman and Dixonville properties, and 1.45% for the Twining properties that were recently acquired (see note 4 "Acquisition") (December 31, 2014 – 2% for Salt Flat, 2.7% for Hardeman and Dixonville).

14. Trust Capital

Trust Units Outstanding

	Nine Months Ended September 30, 2015		Year Ended December 31, 2014	
$000's	**Number of units**	**Amount**	Number of units	Amount
Beginning balance	35,017	317,150	32,149	297,447
Issuance of Trust capital pursuant to DRIP	36	67	2,868	17,421
Cancellation of Trust capital pursuant to NCIB	(160)	(1,548)	-	-
Fair value adjustment	-	-	-	2,319
Trust unit issuance costs	-	-	-	(37)
Ending balance	**34,893**	**315,669**	**35,017**	**317,150**

For the nine months ended September 30, 2015, the Trust incurred $nil (December 31, 2014 - $37,099) of unit issuance costs in conjunction with the Distribution Reinvestment Plan ("DRIP").

Commencing with the distribution paid on February 23, 2015, for unitholders of record on January 30, 2015, Eagle's DRIP was suspended until further notice. Unitholders who had elected to participate in the DRIP will receive cash distributions on future distribution payment dates. Unitholders that were enrolled in the DRIP when the plan was suspended will remain enrolled at reinstatement and will automatically resume participation in the DRIP if, and when, the DRIP is reinstated.

On January 19, 2015, the Trust received acceptance from the Toronto Stock Exchange (the "TSX") of Eagle's notice of intention to make a Normal Course Issuer Bid ("NCIB"). Under the NCIB, during the one-year period commencing January 21, 2015 and ending January 20, 2016, Eagle can purchase for cancellation up to 2,852,829 of its units

("units"), representing ten percent of its public float as of January 16, 2015. The NCIB is administered through the facilities of the TSX, or alternative trading systems, if eligible, and conforms to their regulations.

The actual number of units purchased under the NCIB, the timing of such purchases and the price at which the Units are bought will depend upon future market conditions, and upon potential alternative uses for Eagle's cash resources. Any purchases will be made by Eagle at the prevailing market price of the Units at the time of purchase and will be subject to a maximum daily purchase volume of 30,732 Units (being 25% of the average daily trading volume of the Units from July 1, 2014 to December 31, 2014 of 122,928 units) except as otherwise permitted under the TSX NCIB rules. All Units purchased under the NCIB will be cancelled.

Additionally, Eagle entered into an automatic unit purchase plan (the "Plan") with a broker in order to facilitate repurchases of its Units under its NCIB. Under Eagle's Plan, Eagle's broker may repurchase Units under the NCIB at any time including without limitation when Eagle would ordinarily not be permitted to due to regulatory restrictions or self-imposed trading blackout periods. Purchases will be made by Eagle's broker based on the parameters prescribed by the TSX and the terms of the Plan. The Plan will be in place for the one-year period of the NCIB. The Plan has been reviewed by the TSX

For the nine months ended September 30, 2015, the Trust has purchased and cancelled 160,300 units at a weighted average market price of $2.45 per unit pursuant to the NCIB.

15. Accumulated Cash Distributions

$000's	**September 30, 2015**	December 31 2014
Beginning balance	(116,315)	(80,454)
Accumulated cash distributions	(9,444)	(33,524)
Fair market value of units issued under the DRIP	18	(2,337)
Total accumulated cash distributions	**(125,741)**	(116,315)

In accordance with IFRS 13, at September 30, 2015, the Trust recorded a non-cash fair value adjustment of $17,921 (September 30, 2014 - $nil) for units issued under the DRIP.

16. Commitments

Operating Lease Commitment – Head Office Lease in Calgary, Alberta

On January 1, 2013, the Trust entered into a lease for office space in Calgary which has an approximate 61 month term from January 8, 2013 to February 7, 2018. Future minimum lease payments during the term of the lease approximate $2.4 million and include a leasehold improvements allowance up to $0.3 million, with 28 months and approximately $1.1 million remaining at September 30, 2015.

Operating Lease Commitment - Sublease in Calgary, Alberta

On August 20, 2015, concurrent with the closing of the acquisition of a private company, the Trust assumed an obligation for the private company's office lease. The term of the lease is from March 1, 2011 to February 28, 2017. Future minimum lease payments during the term of the lease approximate $1.4 million, with 17 months and approximately $0.4 million remaining at September 30, 2015.

Operating Lease Commitment – Office Lease in Houston, Texas

The Trust entered into a lease in Houston on April 1, 2011, which originally had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease was extended for an additional 63 month period from October 1, 2013 to December 31, 2017 and the premise space was expanded to incorporate additional square footage. Future minimum lease payments during the term of the lease include a leasehold improvement allowance of $US 0.1 million and approximate $US 0.9 million, with 27 months and approximately $US 0.66 million remaining at September 30, 2015. In $CA the remaining future minimum lease payments approximate $0.9 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.34.

17. Subsequent Events

Debt

The semi-annual redetermination review of the credit facility was held on October 7, 2015, and Eagle's credit facility was reduced to $US 80 million. There were no changes to the pricing, covenants or conditions of the credit facility. The next semi-annual redetermination review of the credit facility will be held no later than May 15, 2016.

Risk Management

On October 1, 2015 the Trust entered into the following financial contract to further mitigate the effects of fluctuating prices on a portion of its production:

- a fixed price financial swap on 1,000 barrels per day of oil fixing the differential between Edmonton light sweet and WTI at $US 3.65 per barrel for the period December 1, 2015 to December 31, 2016.

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

TSX: EGL.UN

Officers

Richard W. Clark
President, Chief Executive Officer and Director

Kelly A. Tomyn
Chief Financial Officer

J. Wayne Wisniewski
Chief Operating Officer

M. Scott Lovett
Vice President, Corporate and Business Development

Eric C. McFadden
Vice President, Capital Markets and Business Development

Jo-Anne M. Bund
General Counsel and Corporate Secretary

Auditors

PricewaterhouseCoopers LLC

Trustee and Transfer Agent

Computershare Trust Company of Canada

Engineering Consultants

Netherland Sewell and Associates, Inc.
McDaniel and Associates Consultants Ltd.

Bankers

Bank of Nova Scotia
Canadian Imperial Bank of Commerce
National Bank of Canada

Legal Counsel

Bennett Jones LLP

EAGLE ENERGY™ TRUST

Calgary Office

Eagle Energy Inc.
Suite 2710, 500 – 4th Avenue SW
Calgary, Alberta T2P 2V6

Phone: (403) 531-1575
Fax: (403) 508-9840
Email: info@eagleenergytrust.com

Houston Office

Eagle Hydrocarbons Inc.
Suite 3005, 333 Clay Street
Houston, Texas 77002

Phone: (713) 300-3245
Fax: (713) 300-3240
Email: info@eagleenergytrust.com

www.EagleEnergyTrust.com