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Second Quarter 2015 Financial Report

EAGLE ENERGY™
TRUST

Management's Discussion and Analysis

August 6, 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 August 6, 2015, should be read in conjunction with the Trust's unaudited interim condensed consolidated financial statements and accompanying notes for the three months and six months ended June 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 June 30, 2015 was $US 1 equal to $CA 1.25 (December 31, 2014 - $US 1 equal to $CA 1.16), and the average foreign exchange rate for the six months ended June 30, 2015 was $US 1 equal to $CA 1.24 (for the six months ended June 30, 2014 - $US 1 equal to $CA 1.10). The average foreign exchange rate for the three months ended June 30, 2015 was $US 1 equal to $CA 1.23 (for the three months ended June 30, 2014 - $US 1 equal to $CA 1.09).

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.

Other financial data 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 June 30, 2015

- Second quarter average working interest sales volumes of 3,034 barrels of oil equivalent per day **("boe/d")** (96% oil, 2% natural gas liquids, 2% natural gas) with production on track to meet 2015 full year guidance of 2,950 to 3,150 boe/d (before giving effect to the recently announced acquisition that is expected to close at the end of August, 2015).
- Reported a 35% increase from the first quarter with second quarter funds flow from operations of $10.5 million ($38.14 per boe).
- Second quarter unitholder distributions maintained at $0.09 per unit ($0.03 per unit per month).
- To the end of the second quarter, 69% of the $13.7 million capital program for 2015 has been executed with results performing to expectations.

Acquisition

On July 22, 2015, the Trust announced that it has entered into an agreement with a private company **("Privateco")** for the acquisition by Eagle of all the issued and outstanding shares of Privateco (the **"Transaction"**). The Transaction is valued at approximately $30 million, including Privateco's indebtedness, and will be funded out of Eagle's existing credit facility of $US 85 million. It will be completed by the amalgamation of Privateco with a newly incorporated Eagle subsidiary and requires Privateco's shareholder approval. The Transaction is expected to close by the end of August 2015. Directors, officers and a number of other Privateco shareholders, owning an aggregate of more than two-thirds of Privateco's shares, have signed support agreements to vote in favor of the Transaction.

Privateco has estimated production of approximately 750 boe/d (64% oil and natural gas liquids) from the Twining field in Alberta. Privateco has been redeveloping the Twining field with horizontal wells in the Pekisko Pool. This pool is estimated to contain discovered oil initially-in-place of approximately 900 million barrels, with a current recovery factor of less than 5%. To date, Privateco has drilled 10 horizontal wells and has built a new battery to handle current and future development plans, which include over 30 locations that Eagle believes have attractive economic returns in the current price environment.

The highlights of the Transaction 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 largest Pekisko oil pool in the Western Canadian Sedimentary Basin.
- 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.
- Eagle's 2015 pro forma debt to cash flow of approximately 2x[1].
- Over 10% accretive to Eagle pro forma cash flow per unit.
- Eagle pro forma corporate payout ratio maintained below 100%[1].
- Privateco's total corporate decline rate is approximately 20%, which maintains Eagle's pro forma current corporate decline rate below 20%.

[1] Based on forecast pricing and foreign exchange rate assumptions in Notes 4(b) and 4(e) of the 2015 Outlook section of this MD&A.

2015 Outlook (excluding the Acquisition, expected to close end of August 2015)

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 is unchanged and excludes the recently announced acquisition (refer to the "Acquisition" section of this MD&A) which is expected to close by the end of August, 2015. Forecast funds flow from operations and debt to trailing cash flow have been updated to include first half actual results and July to December forecast results. Eagle's guidance is summarized as follows:

	2015 Guidance	Notes
Capital Budget	$13.7 mm	1
Working Interest Production	2,950 to 3,150 boe/d	2
Operating Costs per month	$1.8 to $2.0 mm	3
Funds Flow from Operations	$28.8 mm	4
Debt to Trailing Cash Flow	1.2x	

Notes:

(1) The 2015 capital budget of $13.7 million consists of $US 9.9 million for Eagle's operations in the United States and $1.4 million for Eagle's operations in Canada.

a. Based on a forecast $US 55.00 West Texas Intermediate (**"WTI"**) oil price, the 2015 capital budget is expected to deliver a distribution of $0.03 per unit per month ($0.36 per unit annualized) and a corporate payout ratio of 88%.

b. Eagle's 2015 capital budget of $13.7 million consists of the following:

- Salt Flat, Texas
  - 3 (3.0 net) horizontal oil wells
  - Seismic processing, horizontal pump installations
- Hardeman, Texas and Oklahoma
  - 3 (3.0 net) vertical wells
  - 1 (1.0 net) salt water disposal well
  - Facilities and seismic capital
- Dixonville, Alberta (non-operated)
  - Maintenance capital on waterflood

(2) 2015 production forecast consists of 97% oil, 1% natural gas liquids (**"NGLs"**) and 2% gas.

(3) 2015 forecast operating costs result in field netbacks (excluding hedges) of approximately $24.23 per boe at $US 55.00 WTI.

(4) 2015 forecast funds flow from operations is approximately $28.8 million based on the following assumptions:

a. Average working interest production of 3,050 boe/d (the mid-point of the guidance range);

b. Forecast pricing at $US 55.00 per barrel WTI oil, $US 3.00 per Mcf NYMEX gas and $US 19.25 per barrel of NGL (NGL price is calculated as 35% of the WTI price);

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

d. Average operating costs of $1.9 million per month ($US 0.9 million per month for Eagle's operations in the United States and $0.7 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 1.30.

A table showing the sensitivity of Eagle's funds flow to changes in production, exchange rates and commodity pricing 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 price, exchange rates and production:

Sensitivity to Commodity Price

	2015 Average WTI (Production 3,050 boe/d)		
	$US 50 (FX 1.30)	$US 55 (FX 1.30)	$US 60 (FX 1.25)
Funds Flow from Operations	$27.2	$28.8	$29.4
Corporate Payout Ratio	93%	88%	85%
Debt to Trailing Cash Flow	1.3x	1.2x	1.2x

Sensitivity to Production

	2015 Average Production (boe/d) (WTI $US 55, F/X 1.30)		
	2,950	3,050	3,150
Funds Flow from Operations	$27.9	$28.8	$29.6
Corporate Payout Ratio	90%	88%	85%
Debt to Trailing Cash Flow	1.2x	1.2x	1.2x

Assumptions:

(1) Annual distribution is $0.36 per unit.

(2) No new equity issued.

(3) Operating costs of $1.9 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 as follows:

- At $US 50.00 WTI - $US 1.00 equal to $CA 1.30.
- At $US 55.00 WTI - $US 1.00 equal to $CA 1.30.
- At $US 60.00 WTI - $US 1.00 equal to $CA 1.25.

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	2	-
Oil price[2]	+ USD $1.00/bbl WTI	238	0.01
Gas production	+1000 mcf/d	120	-
Oil production	+100 bbls/d	247	0.01
Currency[2]	+CDN weaken by $0.01	58	-
Interest rate	+1% prime	(113)	-

Notes:

(1) Per unit figures are based on 35,015,568 weighted average basic units outstanding for the six months ended June 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 3,015 boe/d.

Consolidated Results of Operations

Production

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Oil (bbl/d)	2,913	2,732	7	2,904	2,639	10
Natural gas (Mcf/d)	394	1,779	(78)	334	1,549	(78)
Natural gas liquids (bbl/d)	56	313	(82)	55	279	(80)
Oil equivalent sales volumes (boe/d @ 6:1)	**3,034**	3,341	(9)	**3,015**	3,176	(5)

Working interest sales volumes for the second quarter of 2015 averaged 3,034 boe/d (96% oil, 2% natural gas liquids, 2% natural gas).

Revenue

$000's	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Oil	15,936	26,597	(39)	29,453	51,124	(41)
Natural gas	82	735	(89)	153	1,322	(88)
Natural gas liquids	81	1,128	(93)	167	2,084	(92)
Other	226	245	(8)	429	245	75
Sales before royalties	**16,325**	28,705	(43)	**30,202**	54,775	(44)

Realized prices						
Oil ($/bbl)	60.12	105.89	(43)	56.04	104.55	(46)
Natural gas ($/Mcf)	2.29	4.54	(49)	2.63	4.71	(44)
Natural gas liquids ($/bbl)	16.08	39.65	(59)	16.68	41.22	(60)
Other ($/bbl)	0.82	0.81	1	0.79	0.43	83
Sales before royalties ($/boe)	59.13	94.42	(37)	55.35	95.27	(42)
Royalties ($/boe)	(12.46)	(25.93)	(52)	(13.03)	(26.05)	(50)
Revenue ($/boe)	**46.66**	68.48	(32)	**42.32**	69.22	(39)

Benchmark prices(1)						
Oil – WTI ($/bbl)	71.23	112.25	(37)	65.82	110.58	(40)
Natural gas – Henry HUB ($/Mcf)	3.37	5.00	(32)	3.42	5.11	(33)

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 June 30, 2015, realized oil prices increased 16% when compared to the previous quarter due to an increase in the quarter over quarter benchmark WTI price.

For the three and six months ended June 30, 2015, sales before royalties decreased by 43% and 44%, 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.

Realized oil prices in Canadian dollars for the three and six months ended June 30, 2015 decreased by 43% and 46%, respectively, which is more than the benchmark WTI decrease due to wider differentials. For the three and six months ended June 30, 2015, the benchmark WTI price, converted into Canadian dollars, decreased 37% and 40%, respectively, when compared to the prior year's comparative periods.

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 $US 1.75 per barrel while continuing to allow the LLS-WTI differential and the Argus P+ differential to float.

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 differential to WTI is approximately $CA 20.50 discount per barrel, but fluctuates.

The above prices do not include realized gains or losses from financial commodity contracts, which amounted to a realized gain of $5.6 million ($20.38/boe) for the three months ended June 30, 2015 and a realized gain of $12.9 million ($23.68/boe) for the six months ended June 30, 2015. See *Realized and unrealized risk management gain/loss.*

The overall royalty rate of approximately 21% for the three months ended June 30, 2015 and 24% for the six months ended June 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

	Three Months Ended June 30, 2015	**Three Months Ended June 30, 2014**	**%**	**Six Months Ended June 30, 2015**	**Six Months Ended June 30, 2014**	**%**
Operating costs	4,662	4,486	4	10,600	8,558	24
Transportation and marketing expenses	509	191	166	1,033	388	166
	5,171	4,677	11	**11,633**	8.946	30
Per boe:						
Operating costs	16.89	14.76	14	19.43	14.88	31
Transportation and marketing expenses	1.84	0.63	193	1.89	0.68	178
	18.73	15.39	22	**21.32**	15.56	37

The Trust intends to continue to improve efficiencies and maintains its 2015 operating expense guidance of $1.8 million to $2.0 million per month. Refer to the "Segmented Operations" section of this MD&A.

Historically, the Trust had included U.S. based crude oil transportation charges as a component of transportation and marketing expenses. Following a review of the Trust's crude oil contracts in the United States during the third quarter of 2014, it was determined that the criteria for revenue recognition are met at the point of sale before the crude oil is transported by its purchasers and any charges levied by its purchasers past the point of sale should be treated as a reduction of the Trust's revenue rather than as a transportation and marketing expense. Consequently, the Trust has restated its U.S based revenue and transportation and marketing expense for the prior year comparative period to reflect this adjustment.

For the three and six months ended June 30, 2014, the impact of the oil transportation restatement to both revenue and transportation and marketing expenses was a $0.5 million and $1.1 million reduction, respectively.

Following a review of the Trust's crude oil contracts in Canada during the second quarter of 2015, it was determined that the criteria for revenue recognition on operations in Canada are met at the point of sale after the crude oil is transported by its purchasers and any charges levied by its purchasers before the point of sale should be treated as a transportation and marketing expense rather than a reduction to revenue. Consequently, the Trust has restated both its revenue and transportation and marketing expense for the first quarter of 2015 to reflect this adjustment.

For the three months ended March 31, 2015, the impact of the oil transportation restatement to both revenue and transportation and marketing expense was a $0.5 million increase.

Depreciation, Depletion and Amortization

$/boe	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Depreciation, depletion and amortization	**21.73**	35.28	(38)	**22.24**	33.77	(34)

The depletion, depreciation, and amortization provision for the three and six months ended June 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.

The disposition of the Permian properties in Martin County, Texas and the acquisition of the Dixonville 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, the percentage of free cash flow realized by the Trust will increase.

Field Netback

	Three Months Ended June 30, 2015		Three Months Ended June 30, 2014		Six Months Ended June 30, 2015		Six Months Ended June 30, 2014	
$000's		**/boe**		/boe		**/boe**		/boe
Sales before royalties	16,325	59.13	28,705	94.42	30,202	55.35	54,775	95.27
Royalties	(3,441)	(12.46)	(7,884)	(25.93)	(7,112)	(13.03)	(14,980)	(26.05)
Operating expenses	(4,662)	(16.89)	(4,486)	(14.76)	(10,600)	(19.43)	(8,558)	(14.88)
Transportation and marketing expenses	(509)	(1.84)	(191)	(0.63)	(1,033)	(1.89)	(388)	(0.68)
Field netback	**7,713**	**27.94**	16,144	53.10	**11,457**	**21.00**	30,849	53.66
Sales volumes (boe/d)		**3,034**		3,341		**3,015**		3,176

During the quarter, benchmark WTI averaged $US 57.94 per barrel and the Trust realized a field netback of $27.94 per boe. For the six months ended June 30, 2015, benchmark WTI averaged $US 53.29 per barrel and the Trust realized a field net back of $21.00 per boe. When compared to the prior year comparative periods, the decrease in field netbacks is primarily due to the sharp drop in commodity prices. Monthly operating costs are tracking to 2015 guidance of $1.8 million to $2.0 million per month and actually decreased on a per boe basis, since the first quarter of 2015. 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)	500	bbls/d	Jul-15	Sep-15	55.45	55.45
NYMEX (i)	200	bbls/d	Jul-15	Sep-15	55.60	55.60
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

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

$000's	**Three Months Ended June 30, 2015**	**Three Months Ended June 30, 2014**	**%**	**Six Months Ended June 30, 2015**	**Six Months Ended June 30, 2014**	**%**
Realized gain (loss) - Commodity	5,626	(1,532)	467	12,922	(2,350)	649
Unrealized gain (loss) - Commodity	(7,984)	(3,847)	(108)	(12,167)	(4,961)	(145)
Net gain (loss) - Commodity	(2,358)	(5,379)	56	755	(7,311)	110
Realized gain (loss) - Foreign exchange	-	(5)	-	-	(29)	-
Unrealized gain (loss) - Foreign exchange	-	192	-	-	(2)	-
Net gain (loss) - Foreign exchange	-	187	-	-	(31)	-
Total net gain (loss)	**(2,358)**	(5,192)	55	**755**	(7,342)	-

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 first quarter of 2015, the forward commodity pricing environment improved slightly, causing the future values of the unrealized contracts to decrease on the balance sheet at June 30, 2015.

Eagle had approximately 1,600 barrels of oil per day hedged at an average WTI price of $US 90.72 per barrel during the second quarter of 2015. For the third quarter of 2015, 1,300 barrels of oil per day are hedged at an average WTI price of $US 69.95; and 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 500 barrels of oil per day hedged at an average WTI price of $US 65.00.

Finance Expense

$000's	**Three Months Ended June 30, 2015**	**Three Months Ended June 30, 2014**	**%**	**Six Months Ended June 30, 2015**	**Six Months Ended June 30, 2014**	**%**
Finance expense	**683**	1,087	(37)	**1,456**	1,964	(26)
Per boe	**2.47**	3.57	(31)	**2.67**	3.42	(22)

For the three months and six months ended June 30, 2015, finance expense decreased over the prior year's comparative period due to the decrease of the Trust's outstanding advances on its credit facility.

As of June 30, 2015, the effective interest rate on bank debt for the period was 3.9% 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 June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Administrative expenses	**2,344**	3,009	(22)	**4,804**	5,564	(14)
Per boe	**8.61**	9.89	(14)	**8.93**	9.68	(9)

Total administrative expenses for the three months ended June 30, 2015 were $2.3 million, representing approximately 21% of full year 2015 expected levels. For the six months ended June 30, 2015, total administrative expenses were $4.8 million, representing approximately 43% of full year expected levels. Staff and related employment costs accounted for 71% of administrative expenses for the six months ended June 30, 2015. In light of the weakened commodity price environment, in the first quarter of 2015 Eagle undertook a comprehensive review of administrative expenses in the previous quarter which resulted in a reduction or termination of various consulting contracts and a 15% reduction in the number of full time employees.

Unit Based Compensation

$000's	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Unit-based compensation expense (recovery)	**991**	(900)	(210)	**868**	(2,774)	(131)

A non-cash unit based compensation expense of $1.0 million was recorded during the second quarter of 2015 ($0.9 million recovery for the three months ended June 30, 2014). This was due to an increase in the unit price at June 30, 2015 when compared to the unit price at the end of the previous quarter, and a change in fair market valuation resulting from an increase in the expected risk free rate when compared to the risk free rate of the previous quarter.

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).

The Trust is, however, required to re-determine the fair value of the liability each quarter relating to: (1) the restricted unit rights, (2) the options and (3) the unit rights. Any changes in fair value are recorded as an expense 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 six months ended June 30, 2015, the recorded expense was due to improved year to date price of the Trust's units. The weighted average exercise price of the unit options of $5.73 is still significantly above the June 30, 2015 closing unit price of $3.08.

During the second quarter, $56,910 was paid out in cash for amounts related to vested restricted unit rights and $113,835 was recorded for the six months ended June 30, 2015 (three and six months ended June 30, 2014 - $166,031 and $332,068, respectively). The decrease in payments year over year is 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.

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 six months ended June 30, 2015, the Trust recorded a foreign exchange gain of $6.0 million. The foreign exchange loss of $1.9 million during the three months ended June 30, 2015 was due to a decrease in the average foreign exchange rate from the previous quarter.

Summary of Quarterly Results

	Q2/2015	Q1/2015	Q4/2014	Q3/2014	Q2/2014	Q1/2014	Q4/2013	Q3/2013
($000's except for boe/d and per unit amounts)								
Sales volumes – boe/d	3,034	2,995	1,929	2,859	3,341	3,010	2,994	3,052
Revenue, net of royalties	12,884	10,206	10,238	17,143	20,821	18,973	17,119	19,046
per boe	46.66	37.86	57.67	65.19	68.48	70.04	62.15	67.84
Field netback	7,713	3,744	6,841	12,832	16,144	14,705	13,106	15,945
per boe	27.94	13.89	38.54	48.80	53.10	54.29	47.58	56.79
Funds flow from operations	10,532	7,727	5,670	7,476	10,471	10,341	8,794	11,615
per boe	38.14	28.67	31.94	28.43	34.44	38.18	31.93	41.37
per unit – basic	0.30	0.22	0.16	0.22	0.32	0.32	0.28	0.37
per unit – diluted	0.30	0.22	0.15	0.16	0.28	0.25	0.28	0.37
Earnings (loss)	(6,541)	5,477	(35,192)	8,104	(23,158)	2,218	156	(3,241)
per unit – basic	(0.19)	0.16	(1.01)	0.24	(0.70)	0.07	-	(0.10)
per unit - diluted	(0.19)	0.16	(1.13)	0.18	(0.70)	0.02	-	(0.10)
Cash distributions declared	3,130	3,153	7,159	9,036	8,775	8,555	8,376	8,204
per issued unit	0.09	0.09	0.21	0.26	0.26	0.26	0.26	0.26
Current assets	13,382	31,459	33,245	76,566	8,802	9,116	9,889	9,950
Current liabilities	7,754	8,642	10,720	13,587	32,878	33,348	30,461	20,942
Total assets	245,009	265,342	257,172	240,458	320,182	356,332	335,679	306,021
Total non-current liabilities	52,012	60,835	57,547	2,565	80,126	79,684	70,521	55,069
Unitholders' equity	185,243	195,865	188,905	224,306	207,178	243,300	234,697	230,010
Units issued	34,961	35,023	35,017	34,821	33,739	32,836	32,149	31,469

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

For the three months ended June 30, 2015, sales volumes remained consistent with the previous quarter. With the exception of the third and fourth quarters of 2014 (which had reduced sales volumes due to the Permian property disposition), production has remained generally consistent.

Funds flow from operations increased in the second quarter of 2015 when compared to the prior quarter due to higher realized commodity prices and lower operating costs. Generally, in times of steady or increasing prices, funds flow from operations grows faster than increases 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. Second quarter 2015 funds flow from operations increased 35% from the first quarter 2015 while earnings in the first quarter swung to a loss in the second quarter. This occurred primarily due to a non-cash foreign exchange loss recognized on the loan to the Trust's US subsidiary and a decrease in value in the risk management contracts. The forward commodity price environment improved in the second quarter of 2015, decreasing the fair market valuation of Eagle's forward commodity contracts.

Eagle had approximately 1,600 barrels of oil per day hedged at an average WTI price of $US 90.72 during the second quarter of 2015. For the third quarter of 2015, 1,300 barrels of oil per day are hedged at an average WTI price of $US 69.95; and 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 500 barrels of oil per day hedged at an average WTI price of $US 65.00.

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 June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Production						
Oil (bbls/d)	1,780	2,732	(35)	1,773	2,639	(33)
Natural gas (mcf/d)	282	1,779	(84)	257	1,549	(83)
Natural gas liquids (bbls/d)	56	313	(82)	55	279	(80)
Oil equivalent sales volumes (boe/d @ 6:1)	**1,883**	3,341	(44)	**1,871**	3,176	(41)
Activity						
Capital expenditures ($000's)	**7,366**	6,519	13	**9,576**	23,357	(59)
Wells drilled (rig-released)						
Gross	6	2	200	6	4	50
Net	6.0	2.0	200	6.0	3.6	67
Wells brought on-stream						
Gross	4	2	100	4	4	-
Net	4.0	2.0	100	4.0	3.6	11

$000's	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Sales before royalties	11,369	28,705	(60)	20,971	54,775	(62)
Royalties	(3,187)	(7,884)	(60)	(5,989)	(14,980)	(60)
Operating expenses	(2,740)	(4,486)	(39)	(6,596)	(8,558)	(23)
Transportation and marketing expenses	(31)	(191)	(84)	(62)	(388)	(92)
Field netback	**5,411**	16,144	(66)	**8,324**	30,849	(73)
($/boe)						
Sales before royalties	66.36	94.42	(30)	61.94	95.27	(35)
Royalties	(18.60)	(25.93)	(28)	(17.69)	(26.05)	(32)
Operating expenses	(16.00)	(14.76)	8	(19.48)	(14.88)	30
Transportation and marketing expenses	(0.18)	(0.63)	(72)	(0.18)	(0.68)	(73)
Field netback	**31.58**	53.10	(41)	**24.59**	53.66	(54)

Operating expenses for the second quarter decreased 31% on a per barrel basis when compared to the first quarter due to ongoing operating expense reduction initiatives.

During the second quarter of 2015, capital expenditures were $7.4 million in the United States with average working interest sales volumes of 1,883 boe/d. To date, results from the capital program have met expectations and the Trust is on track to meet its 2015 guidance.

Salt Flat Properties, Texas

At Salt Flat, Eagle installed two horizontal pumps in older wells, drilled, completed and tied-in three wells, and performed facility upgrades. The capital efficiency of this project was exceptional, at a cost of less than $20,000 per flowing barrel per day.

Hardeman Properties, Texas and Oklahoma

At Hardeman, Eagle drilled three wells including a salt water disposal well, which is expected to come into service late in the third quarter of 2015. Eagle has implemented a number of enhancements that have resulted in production gains and these salt water disposal facilities are expected to further reduce operating expenses in the southern part of the Hardeman area.

Canada

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Production						
Oil (bbls/d)	1,132	-	-	1,131	-	-
Natural gas (mcf/d)	112	-	-	77	-	-
Natural gas liquids (bbls/d)	-	-	-	-	-	-
Oil equivalent sales volumes (boe/d @ 6:1)	**1,151**	**-**	**-**	**1,144**	-	-
Activity						
Capital expenditures ($000's)	**(982)**	-	-	**(133)**	-	-

$000's	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Sales before royalties	4,956	-	-	9,231	-	-
Royalties	(254)	-	-	(1,123)	-	-
Operating expenses	(1,922)	-	-	(4,004)	-	-
Transportation and marketing expenses	(478)	-	-	(971)	-	-
Field netback	**2,302**	**-**	**-**	**3,133**	-	-
($/boe)						
Sales before royalties	47.31	-	-	44.58	-	-
Royalties	(2.42)	-	-	(5.42)	-	-
Operating expenses	(18.34)	-	-	(19.34)	-	-
Transportation and marketing expenses	(4.57)	-	-	(4.69)	-	-
Field netback	**21.98**	**-**	**-**	**15.13**	-	-

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 budget in Canada will be limited to maintenance capital at Dixonville.

Capital expenditures at Dixonville for the three months ended June 30, 2015 consist of a $1.0 million credit to capital with respect to the 2014 Dixonville acquisition and a $0.1 million expenditure on maintenance capital.

Corporate

$000's	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	%	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	%
Administrative expenses	(55)	(1,220)	(95)	(563)	(1,728)	(67)
Risk management gain (loss) - realized	5,626	(1,537)	466	12,922	(2,379)	643
Cash settled award payments	(56)	(196)	(71)	(113)	(362)	(69)
Finance expense	(452)	(919)	(51)	(1,024)	(1,677)	39
Realized foreign exchange gain (loss)	1	(12)	108	(223)	(55)	(247)
Funds flow from operations	**5,064**	(3,884)	230	**10,999**	(6,201)	277

For the three and six months ended June 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.

At the Corporate level, on a quarter over quarter basis, the net value of commodity price contracts decreased as the forward commodity pricing environment improved, causing the future value of the unrealized contracts to decrease. The net value of these contracts is dependent upon current and forward commodity pricing and, in the case of realized gains and losses, also upon the price of the contract relative to the benchmark oil price at time of settlement.

As a result of the Trust reducing its distribution from $0.0875 to $0.03 per unit per month, cash settled award payments decreased when compared to the same quarter of the previous year.

For the three months and six months ended June 30, 2015, finance expenses decreased over the prior year’s comparative period, due to the decrease in the Trust’s outstanding advances on its $106 million ($US 85 million) credit facility. (Refer to the “Finance Expense” 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 "Acquisition" and "2015 Outlook" sections of this MD&A for the net 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 future plans. Other than the items noted in the "Commitments" section of this MD&A, capital spending and distributions are discretionary.

Funds Flow from Operations

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

	Three Months Ended June 30, 2015		**Three Months Ended June 30, 2014**		**Six Months Ended June 30, 2015**		**Six Months Ended June 30, 2014**	
$000's		**/boe**		/boe		**/boe**		/boe
Field netback	7,713	27.93	16,144	53.10	11,457	21.00	30,849	53.66
Cash settled award payments	(56)	(0.21)	(196)	(0.64)	(113)	(0.21)	(362)	(0.62)
Administrative expenses	(2,344)	(8.49)	(3,009)	(9.89)	(4,804)	(8.80)	(5,564)	(9.68)
Realized risk management gain (loss)	5,626	20.38	(1,537)	(5.06)	12,922	23.68	(2,379)	(4.14)
Finance expense	(452)	(1.64)	(919)	(3.03)	(1,024)	(1.87)	(1,677)	(2.92)
Income tax recovery	44	0.16	-	-	44	0.08	-	-
Realized foreign exchange gain (loss)[(1)]	1	-	(12)	(0.04)	(223)	(0.41)	(55)	(0.10)
Funds flow from operations	**10,532**	**38.14**	10,471	34.44	**18,259**	**33.46**	20,812	36.20

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

During the second quarter, Eagle renewed its credit facility at $US 85 million and the maturity date of the credit facility was extended to May 26, 2017. Pricing remained the same and there were no material changes made to the covenants or conditions of the credit facility. The next semi-annual borrowing base review of the credit facility is scheduled for mid-October, 2015.

As of June 30, 2015, the Trust had approximately $66 million ($US 53.0 million) of unused credit on its $106 million ($US 85 million) revolving credit facility, which is held indirectly through its subsidiaries with a syndicate of Canadian chartered banks. On July 22, 2015, the Trust announced a $30 million transaction to acquire a private company, which will be funded out of Eagle's existing credit facility. Refer to the "Acquisition" section of this MD&A.

Working Capital

At June 30, 2015, the Trust had a working capital surplus, excluding non-cash unit-based payments and non-cash risk management asset, of approximately $4.2 million and $40.0 million ($US 32.0 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 second 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 second quarter of 2015, the Trust had purchased for cancellation 62,000 units at a weighted average market price of $2.04 per unit. For the six months ended June 30, 2015, the Trust purchased for cancellation 92,300 units at a weighted average market price of $2.67 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 June 30, 2015, December 31, 2014 and June 30, 2014 is as follows:

$000's	**Six Months Ended June 30, 2015**	**Year Ended December 31, 2014**	**Six Months Ended June 30, 2014**
Number of units issued under the DRIP	36,552	2,868,203	1,590,067
Fair market value of units issued under the DRIP	-	2,319	-
Net proceeds from issuance of Trust capital (000's)	67	17,421	10,571
Average price per unit issued under the DRIP	1.84	6.07	6.67
Number of trust units cancelled pursuant to the NCIB	(92,300)	-	-
Reduction of Trust capital pursuant to the NCIB (000's)	(892)	-	-
Average price per unit cancelled pursuant to the NCIB	2.67	-	-

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 second quarter (for the March, April and May 2015 record dates) totaled approximately $3.2 million.

At June 30, 2015, the Trust had issued 34,961,364 units (December 31, 2014 – 35,017,112; June 30, 2014 – 33,738,976).

As at the date of this MD&A, 34,941,364 units are issued and 3,241,750 options are outstanding.

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 June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Earnings (loss) for the period	(6,541)	(23,158)	(1,064)	(20,940)
Cash distributions paid	(3,148)	(8,696)	(6,301)	(17,191)
Excess (shortfall) of earnings over cash distributions paid	**(9,689)**	(31,854)	**(7,365)**	(38,131)
Funds flow from operations[1]	10,532	10,471	18,259	20,812
Changes in operating working capital	(1,816)	34	(7,224)	407
Net cash provided by operating activities	8,716	10,505	11,035	21,219
Cash distributions paid	(3,148)	(8,696)	(6,301)	(17,191)
Excess (shortfall) of net cash provided by operating activities over cash distributions paid	**5,568**	1,809	**4,734**	4,028

Note:

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

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

Capital Expenditures

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

$000's	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Exploration and evaluation[1]	-	-	-	16
Acquisition - Hardeman	-	99	-	5,409
Intangible drilling and completions	4,777	4,537	6,741	13,555
Seismic	-	747	-	2,947
Well equipment and facilities	1,606	1,126	2,702	1,409
Other	5	10	5	21
	6,388	6,519	**9,448**	23,357

Note:

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

Refer to the "Segmented operations" 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)	2,178	729	1,449
Total contractual obligations	**2,178**	**729**	**1,449**

Notes:

(1) Calgary, Alberta office lease: 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 an available leasehold improvements allowance up to $0.3 million, with 31 months and approximately $1.3 million remaining at June 30, 2015.

(2) Houston, Texas office lease: The Trust entered into a lease in Houston on April 1, 2011, which 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 improvements allowance of $US 0.1 million and approximately $US 0.9 million. At June 30, 2015, approximately 30 months and approximately $US 0.7 million remain in future lease payments. 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 1.25.

Non-IFRS Financial Measures

Statements throughout this MD&A make reference to the terms “funds flow from operations”, “field netback” and “corporate payout ratio”, 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.

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 June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Earnings (loss)	**(6,541)**	(23,158)	**(1,064)**	(20,940)
Add back (deduct) items not involving cash				
Unit-based compensation – non-cash portion	934	(1,096)	754	(3,136)
Unrealized risk management loss (gain)	7,984	3,655	12,167	4,963
Depreciation, depletion and amortization	6,033	10,776	12,203	19,512
Impairment	-	20,126	-	20,126
Finance expense	232	168	433	287
Foreign exchange loss (gain) on intercompany loan	1,890	-	(6,234)	-
Funds flow from operations	**10,532**	10,471	**18,259**	20,812
Add back (deduct items not directly related to field operations				
Finance expense (cash portion)	452	919	1,024	1,677
Realized foreign exchange loss (gain)	(1)	12	223	55
Risk management (gain) loss-realized	(5,626)	1,537	(12,922)	2,379
Administrative expenses	2,344	3,009	4,804	5,564
Income tax recovery	(44)	-	(44)	-
Cash settled award payments	56	196	113	362
Field netback	**7,713**	16,144	**11,457**	30,849

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

During the period beginning on April 1, 2015 through June 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 second quarter of 2015. Further information about the Trust’s critical accounting estimates and judgments can be found in the notes to the 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 six months ended June 30, 2015 that 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 Transaction, including the Transaction value, anticipated closing date, estimates of discovered oil initially-in-place and reserves, and drilling locations of Privateco, as well as estimates of pro forma debt to cash flow, cash flow per unit, corporate payout ratio and corporate decline rates following completion of the Transaction;
- 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, exchange rates and commodity prices;
- estimated corporate decline rates, sustaining capital and future development costs associated with reserves;
- anticipated crude oil, natural gas liquids and natural gas production levels;
- the Trust's expectations regarding production from the Dixonville property during the second quarter of 2015; 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:

- completion of the Transaction;
- 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 have been prepared by Privateco's independent reserves evaluator. The effective date of the reserves estimates is 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™
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Eagle Energy Trust

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

For the three months and six months ended June 30, 2015 and June 30, 2014

Eagle Energy Trust

Condensed Consolidated Balance Sheets

(Thousands of Canadian dollars) (unaudited)

	Note	**June 30, 2015**	December 31, 2014
ASSETS			
Current assets			
Cash		174	11,127
Trade and other receivables		9,492	6,669
Prepaid expenses		247	530
Risk management asset	3	3,469	14,919
		13,382	**33,245**
Non-current assets			
Risk management asset		291	-
Oil and gas properties	9	230,305	222,939
Property, plant and equipment		167	219
Other intangible assets		864	769
		231,627	**223,927**
Total Assets		**245,009**	**257,172**
LIABILITIES			
Current liabilities			
Trade and other payables		4,616	8,316
Distributions payable		1,049	1,068
Unit-based payments	5	2,089	1,336
		7,754	**10,720**
Non-current liabilities			
Debt	10	40,000	47,200
Deferred income tax	7	-	-
Decommissioning liability	11	12,012	10,347
		52,012	**57,547**
Total Liabilities		**59,766**	**68,267**
UNITHOLDERS' EQUITY			
Trust capital	12	316,325	317,150
Currency reserves		33,362	29,494
Accumulated loss		(41,846)	(41,424)
Accumulated cash distributions	13	(122,598)	(116,315)
Total Unitholders' Equity		**185,243**	**188,905**
Total Liabilities and Unitholders' Equity		**245,009**	**257,172**

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

See note 14 "Commitments" and note 15 "Subsequent events".

Eagle Energy Trust

Condensed Consolidated Statements of Loss and Comprehensive Earnings (Loss)

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

	Note	**Three Months Ended June 30, 2015**	Three Months Ended June 30, 2014-Revised[1]	**Six Months Ended June 30, 2015**	Six Months Ended June 30, 2014-Revised[1]
Revenue		16,325	28,705	30,202	54,775
Royalties		(3,441)	(7,884)	(7,112)	(14,980)
		12,884	20,821	**23,090**	39,795
Operating expenses		4,662	4,486	10,600	8,558
Transportation and marketing expenses		509	191	1,033	388
Administrative expenses		2,344	3,009	4,804	5,564
Impairment		-	20,126	-	20,126
Depreciation, depletion and amortization		6,033	10,776	12,203	19,512
Operating loss		**(664)**	(17,767)	**(5,550)**	(14,353)
Unit based compensation expense (recovery)	5	991	(900)	868	(2,774)
Finance expense	6	683	1,087	1,456	1,964
Risk management loss (gain)	3	2,358	5,192	(755)	7,342
Foreign exchange loss (gain) net		(1)	12	223	55
Foreign exchange loss (gain) on intercompany loan		1,890	-	(6,234)	-
Loss before taxes		**(6,585)**	(23,158)	**(1,108)**	(20,940)
Income tax recovery	7	(44)	-	(44)	-
Loss		**(6,541)**	(23,158)	**(1,064)**	(20,940)
Other comprehensive earnings (loss)					
Items that may be reclassified subsequently to earnings (loss)					
Foreign currency translation gain (loss)		(743)	(9,565)	3,868	179
Comprehensive earnings (loss)		**(7,284)**	(32,723)	**2,804**	(20,761)
Loss per unit					
Basic and diluted	8	**(0.19)**	(0.70)	**(0.03)**	(0.64)

[1] See note 2.2 “Changes in accounting policy and disclosures”.

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

Eagle Energy Trust

Condensed Consolidated Statements of Changes in Unitholders' Equity

For the six months ended June 30, 2015 and June 30, 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	8	-	-	-	(20,940)	-	(20,940)	(20,940)
Foreign currency translation gain		-	-	179	-	-	-	179
Total comprehensive earnings (loss)		-	-	179	(20,940)	-	(20,940)	(20,761)
Issuance of trust capital		1,590	10,609		-	-	-	10,609
Trust unit issuance costs		-	(37)	-	-	-	-	(37)
Unitholder distributions		-	-	-	-	(17,330)	(17,330)	(17,330)
		1,590	10,572	-	-	(17,330)	(17,330)	(6,758)
Balance at June 30, 2014		**33,739**	**308,019**	**11,279**	**(14,336)**	**(97,784)**	**(112,120)**	**207,178**
Balance at December 31, 2014		**35,017**	**317,150**	**29,494**	**(41,424)**	**(116,315)**	**(157,739)**	**188,905**
Loss	8	-	-	-	(1,064)	-	(1,064)	(1,064)
Foreign currency translation gain		-	-	3,868	-	-	-	3,868
Total comprehensive earnings (loss)		-	-	3,868	(1,064)	-	(1,064)	2,804
Issuance of trust capital	12	36	67	-	-	-	-	67
Cancellation of trust capital pursuant to NCIB	12	(92)	(892)	-	642	-	642	(250)
Unitholder distributions	13	-	-	-	-	(6,283)	(6,283)	(6,283)
		(56)	(825)	-	642	(6,283)	(5,641)	(6,466)
Balance at June 30, 2015		**34,961**	**316,325**	**33,362**	**(41,846)**	**(122,598)**	**(164,444)**	**185,243**

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

Eagle Energy Trust

Condensed Consolidated Cash Flow Statements

For the three months and six months ended June 30, 2015 and June 30, 2014

(Thousands of Canadian dollars) (unaudited)

	Note	**Three Months Ended June 30, 2015**	Three Months Ended June 30, 2014	**Six Months Ended June 30, 2015**	Six Months Ended June 30, 2014
Cashflows from operating activities					
Loss		(6,541)	(23,158)	(1,064)	(20,940)
Adjustments for non-cash items:					
Impairment		-	20,126	-	20,126
Depreciation, depletion and amortization		6,033	10,776	12,203	19,512
Unit-based compensation – non-cash portion		934	(1,096)	754	(3,136)
Unrealized risk management loss		7,984	3,655	12,167	4,963
Foreign exchange loss (gain) on intercompany loan		1,890	-	(6,234)	-
Finance expense		232	168	433	287
		10,532	10,471	18,259	20,812
Changes in working capital:					
Trade and other receivables		(1,199)	49	(2,348)	(362)
Prepaid expenses		156	(39)	311	33
Trade and other payables		258	24	(4,156)	736
		(785)	34	(6,193)	407
Net cash generated by operating activities		**9,747**	**10,505**	**12,066**	**21,219**
Cash flows from investing activities					
Exploration and evaluation		-	-	-	(16)
Oil and gas properties		(6,384)	(6,410)	(9,443)	(17,910)
Property, plant and equipment		(4)	(10)	(5)	(22)
Acquisition of oil and gas assets		-	(99)	-	(5,409)
Change in non-cash working capital		(2,595)	(1,635)	(60)	728
Net cash used in investing activities		**(8,983)**	**(8,154)**	**(9,508)**	**(22,629)**
Cash flows from financing activities					
Debt		(7,650)	944	(7,200)	6,579
Proceeds from issuance of units		-	5,368	67	10,609
Purchase of trust units for cancellation		(191)	-	(250)	-
Trust unit issue costs		-	8	-	(37)
Cash distributions to unitholders		(3,130)	(8,696)	(6,283)	(17,191)
Deferred financing charges		(189)	(152)	(365)	(297)
Net cash used in financing activities		**(11,160)**	**(2,528)**	**(14,031)**	**(337)**
Net decrease in cash and cash equivalents		**(10,396)**	**(177)**	**(11,473)**	**(1,747)**
Effects of exchange rates on cash and cash equivalents		(76)	177	520	314
Cash at beginning of the period		10,646	-	11,127	1,435
Cash at end of the period		**174**	**-**	**174**	**-**

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

Eagle Energy Trust

Notes to Condensed Consolidated Financial Statements (unaudited)

For the three months and six months ended June 30, 2015 and June 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. and Eagle Energy Canada 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 June 30, 2015 was $US 1 equal to $CA 1.25 (December 31, 2014 - $US 1 equal to $CA 1.16), and the average foreign exchange rate for the six months ended June 30, 2015 was $US 1 equal to $CA 1.24 (for the six months ended June 30, 2014 - $US 1 equal to $CA 1.10).

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 August 6, 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 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.

Historically, the Trust has included U.S based crude oil transportation charges as a component of transportation and marketing expenses. Following a review of the Trust's U.S. based crude oil contracts during the third quarter of 2014, it was determined that the criteria for revenue recognition on operations in the United States are met at the point of sale before the crude oil is transported by its purchasers and any charges levied by its purchasers past the point of sale should be treated as a reduction of the Trust's revenue rather than as a transportation and marketing expense.

Consequently, the Trust has restated its revenue and transportation and marketing expense for the prior year comparative period to reflect this adjustment.

For the three months and six months ended June 30, 2014, the impact of the oil transportation restatement to both revenue and transportation and marketing expenses was a $0.5 million and $1.1 million reduction, respectively.

Following a review of the Trust's crude oil contracts in Canada during the second quarter of 2015, it was determined that the criteria for revenue recognition on operations in Canada are met at the point of sale after the crude oil is transported by its purchasers and any charges levied by its purchasers before the point of sale should be treated as a transportation and marketing expense rather than a reduction to revenue. Consequently, the Trust has restated both its revenue and transportation and marketing expense for the first quarter of 2015 to reflect this adjustment.

For the three months ended March 31, 2015, the impact of the oil transportation restatement to both revenue and transportation and marketing expenses was a $0.5 million increase.

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 June 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.

At June 30, 2015, there was no material change in the contractual undiscounted cash outflow for financial liabilities compared to the December 31, 2014 year end.

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 June 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	1,093	-
NYMEX (i)	400	bbls/d	Jul-15	Dec-15	87.90	87.90	2,530	-
NYMEX (i)	500	bbls/d	Jul-15	Sep-15	55.45	55.45	(256)	-
NYMEX (i)	200	bbls/d	Jul-15	Sep-15	55.60	55.60	(99)	-
NYMEX (i)	400	bbls/d	Oct-15	Dec-15	57.10	57.10	(172)	-
NYMEX (i)	500	bbls/d	Jan-16	Dec-16	65.00	65.00	373	291
Unrealized risk management asset							**3,469**	**291**

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

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

	Three Months Ended June 30, 2015			Three Months Ended June 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	(5,626)	7,984	2,358	1,532	3,847	5,379
Net effect - foreign exchange	-	-	-	5	(192)	(187)
Net effect - risk management	**(5,626)**	**7,984**	**2,358**	1,537	3,655	5,192

	Six Months Ended June 30, 2015			Six Months Ended June 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	(12,922)	12,167	(755)	2,350	4,961	7,311
Net effect - foreign exchange	-	-	-	29	2	31
Net effect - risk management	**(12,922)**	**12,167**	**(755)**	2,379	4,963	7,342

Determination of Fair Values

The net fair value of Eagle's unrealized risk management positions at June, 30, 2015 is an asset of $3.8 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. 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.

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

	Three months ended June 30, 2015			
$000's	**Canada**	**United States**	**Corporate**	**Total**
Capital expenditures	(982)	7,366	4	6,388
Revenue	4,956	11,369	-	16,325
Royalties	(254)	(3,187)	-	(3,441)
Revenue net of royalties	4,702	8,182	-	12,884
Operating expenses	1,922	2,740	-	4,662
Transportation and marketing expenses	478	31	-	509
	2,302	**5,411**	**-**	**7,713**
Administrative expenses	103	2,186	55	2,344
Cash settled award payments	-	-	56	56
Risk management gain - realized	-	-	(5,627)	(5,627)
Finance expense (cash portion)	-	-	453	453
Income tax recovery	-	(44)	-	(44)
Realized foreign exchange gain	-	-	(1)	(1)
Funds flow from operations	**2,199**	**3,269**	**5,064**	**10,532**

	Six months ended June 30, 2015			
$000's	**Canada**	**United States**	**Corporate**	**Total**
Capital expenditures	(133)	9,576	5	9,448
Total assets	**109,707**	**131,542**	**3,760**	**245,009**
Revenue	9,231	20,971	-	30,202
Royalties	(1,123)	(5,989)	-	(7,112)
Revenue net of royalties	8,108	14,982	-	23,090
Operating expenses	4,004	6,596	-	10,600
Transportation and marketing expenses	971	62	-	1,033
	3,133	**8,324**	**-**	**11,457**
Administrative expenses	149	4,091	564	4,804
Cash settled award payments	-	-	113	113
Risk management gain - realized	-	-	(12,922)	(12,922)
Finance expense (cash portion)	-	-	1,023	1,023
Income tax recovery	-	(44)	-	(44)
Realized foreign exchange loss	-	-	223	223
Funds flow from operations	**2,984**	**4,276**	**10,999**	**18,259**

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

	Three months ended June 30, 2015			
$000's	**Canada**	**United States**	**Corporate**	**Total**
Funds flow from operations	**2,199**	**3,269**	**5,064**	**10,532**
Unit based compensation - non-cash portion	-	-	934	934
Risk management loss - unrealized	-	-	7,984	7,984
Depreciation, depletion and amortization	1,169	4,864	-	6,033
Foreign exchange gain on intercompany loan	-	-	1,890	1,890
Finance expense (non-cash portion)	-	-	232	232
Earnings (loss)	**1,030**	**(1,640)**	**(5,931)**	**(6,541)**

	Six months ended June 30, 2015			
$000's	**Canada**	**United States**	**Corporate**	**Total**
Funds flow from operations	**2,984**	**4,233**	**11,043**	**18,259**
Unit based compensation - non-cash portion	-	-	754	754
Risk management loss - unrealized	-	-	12,167	12,167
Depreciation, depletion and amortization	2,453	9,750	-	12,203
Foreign exchange gain on intercompany loan	-	-	(6,234)	(6,234)
Finance expense (non-cash portion)	-	-	433	433
Earnings (loss)	**531**	**(5,517)**	**3,923**	**(1,064)**

Total assets of the Trust's reportable segments at December 31, 2014 were as follows:

	Year-ended December 31, 2014			
$000's	Canada	United States	Corporate	Total
Total Assets	**108,616**	**133,637**	**14,919**	**257,172**

The Canadian segment arose due to the acquisition of the Dixonville property on December 18, 2014. As the effective date of the acquisition was January 1, 2015, the Trust did not disclose its operating activities by segment at December 31, 2014.

5. Unit-based Payments

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

$000's	Note	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Restricted Unit Rights	5(a)	114	(96)	120	(475)
Unit Options	5(b)	803	(282)	831	(1,707)
Unit Rights	5(c)	74	(522)	(83)	(592)
Total unit-based compensation expense (recovery)		**991**	(900)	**868**	(2,774)

The following table reconciles the unit-based payments liability:

$000's	Note	June 30, 2015	December 31, 2014
Restricted Unit Rights	5(a)	66	61
Unit Options	5(b)	1,763	932
Unit Rights	5(c)	260	343
Total unit-based payments liability		**2,089**	1,336

Note (a)

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

For the six months ended June 30, 2015, $113,835 has been paid to the RUR holders (year ended December 31, 2014 - $664,072, six months ended June 30, 2014 – $332,068).

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

	Six Months Ended June 30, 2015	Year Ended December 31, 2014	Six Months Ended June 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:

	June 30, 2015	December 31, 2014	June 30, 2014
Fair value at the balance sheet date ($)	0.19	0.10	4.93
Volatility (%)	35	36	28
Life of RURs (years)	5.5	6.0	6.5
Risk-free interest rate (%)	1.78	1.83	2.31

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:

	Six Months Ended June 30, 2015		Year Ended December 31, 2014		Six Months Ended June 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	(190,000)	2.57	(45,000)	5.51	-	-
Exercised	-	-	-	-	-	-
Granted	-	-	350,000	5.35	50,000	8.04
Outstanding at end of period	**3,241,750**	**5.73**	3,431,750	5.94	3,126,750	6.55
Exercisable at end of period	**2,241,761**	**5.70**	2,109,095	6.01	1,657,847	6.33

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

	Weighted average exercise price	Weighted average contractual life (years)
$4.69 - $7.34	**5.73**	**7.0**

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

	June 30, 2015	December 31, 2014	June 30, 2014
Fair value - at balance sheet date ($)	0.66	0.37	2.36
Unit trading price - closing ($)	3.08	2.33	6.48
Exercise price – weighted average ($)	5.73	5.94	6.55
Volatility (%)	35	36	28
Option life – weighted average (years)	7.0	7.6	7.9
Distributions – none estimated, due to declining strike price feature (%)	-	-	-
Risk-free interest rate (%)	1.78	1.83	2.31

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

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

	Six Months Ended June 30, 2015	Year Ended December 31, 2014	Six Months Ended June 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	387,172	465,007	289,339

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:

	June 30, 2015	December 31, 2014	June 30, 2014
Fair value at the balance sheet date	0.48	0.50	2.10
Volatility (%)	35	36	28
Life of RURs (years)	7.7	8.1	8.7
Risk-free interest rate (%)	1.78	1.83	2.31

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.

6. Finance Expense

$ 000's	**Three Months Ended June 30, 2015**	Three Months Ended June 30, 2014	**Six Months Ended June 30, 2015**	Six Months Ended June 30, 2014
Interest expense on debt	354	913	842	1,666
Amortization of deferred financing costs	170	144	304	240
Standby and bank fees	99	6	181	11
Accretion of decommissioning provision	60	24	129	47
Finance expense	**683**	1,087	**1,456**	1,964

7. Taxation

Reconciliation of Effective Tax Rate

The income tax provision differs from the amount that would have been expected if the reported 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 June 30, 2015**	Three Months Ended June 30, 2014	**Six Months Ended June 30, 2015**	Six Months Ended June 30, 2014
Loss before taxation	(6,585)	(23,158)	(1,108)	(20,940)
Expected tax rate (%)	26	35	26	35
Expected income tax provision	(1,712)	(8,105)	(288)	(7,329)
Decrease (Increase) resulting from:				
Non-deductible items – permanent differences				
Administrative expenses of the Trust	8	(74)	146	248
Unit-based compensation	213	(315)	196	(971)
Foreign exchange loss (gain), net	1,483	383	(3,217)	169
Foreign tax rate differentials	(495)	-	(909)	-
Change in statutory rate(1)	(27)		(27)	
Changes in temporary differences for which no amounts are recognized	1,066	9,487	5,215	10,620
Items deductible at the subsidiary level				
Interest on internal debt of subsidiary	(563)	(1,378)	(1,170)	(2,742)
Other	(17)	2	10	5
Total income tax recovery(2)	**(44)**	-	**(44)**	-

(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	**June 30, 2015**	December 31, 2014
Deferred tax liabilities		
Oil and gas properties in excess of tax value	4,560	3,422
Less deferred tax assets:		
Non-capital losses	(38,586)	(32,216)
Net deferred tax liability (asset) – before valuation allowance	(34,026)	(28,794)
Unrecognized deferred tax asset	34,026	28,794
Net deferred tax liability (asset)	-	-

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.

8. Loss per Unit

$ 000's	**Three Months Ended June 30, 2015**	Three Months Ended June 30, 2014	**Six Months Ended June 30, 2015**	Six Months Ended June 30, 2014
Loss attributable to unitholders - basic and diluted	(6,541)	(23,158)	(1,064)	(20,940)
Weighted average number of units outstanding – basic and diluted	35,000	33,019	35,016	32,815
Loss per unit – basic and diluted	**(0.19)**	(0.70)	**(0.03)**	(0.64)

9. 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	9,607	1,235	-	10,842
Effects of foreign exchange	19,672	612	-	20,284
At June 30, 2015	**394,519**	9,829	**-**	**404,348**
Accumulated depreciation, depletion and amortization				
At December 31, 2014	(89,354)	(4,242)	(56,687)	(150,283)
Depreciation - impairment	-	-	4,208	4,208
Depreciation	(15,821)	(630)	-	(16,451)
Effects of foreign exchange	(6,848)	(325)	(4,344)	(11,517)
At June 30, 2015	**(112,023)**	**(5,197)**	**(56,823)**	**(174,043)**
Net book value				
At December 31, 2014	275,886	3,740	(56,687)	222,939
Net change for the period	6,610	892	(136)	7,366
At June 30, 2015	**282,496**	**4,632**	**(56,823)**	**230,305**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $36.7 million (December 31, 2014 - $42.9 million) were included in the depletion calculation.

10. Debt

As a result of the April 1, 2015 semi-annual redetermination, Eagle renewed its credit facility at $US 85 million and the maturity date of the credit facility was extended to May 26, 2017. Pricing remained the same and there were no material changes made to the credit facility conditions or covenants. The next semi-annual borrowing base review by credit facility lenders is scheduled for October 16, 2015.

For the six month period ended June 30, 2015, the interest rate on the revolving credit facility was approximately 3.9%. At June 30, 2015, there were no covenant violations under or in connection with the credit facility.

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

$000's	$US	$CA
Authorized (revolving)	85,000	106,165
Less:		
Amounts drawn	32,026	40,000
Available	52,974	66,165

The exchange rate in effect at June 30, 2015 was $US 1 equal to $CA 1.25. The amount drawn on the credit facility at June 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 equal to $CA 1.16. The amount drawn on the credit facility at December 31, 2014 was denominated in Canadian funds.

11. Decommissioning Liability

$000's	**Six Months Ended June 30, 2015**	Year Ended December 31, 2014
Beginning balance	10,347	3,036
Acquisition	-	472
Additions	115	344
Changes in estimates	1,212	7,981
Disposition	-	(1,189)
Abandonment expenditures	-	(212)
Accretion (unwinding of discount)	129	78
Effects of exchange rate	209	(163)
Ending balance	**12,012**	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 provisions is uncertain and is dependent on various items which are not always within Management's control.

The provision was estimated using existing technology, at current prices (adjusted for a 2.0% annual inflation rate), and discounted using a risk-free discount rate at June 30, 2015 of 1.7% for the Salt Flat properties, and 2.3% for the Hardeman and Dixonville properties (December 31, 2014 – 2% for Salt Flat, 2.7% for Hardeman and Dixonville).

12. Trust Capital

Trust Units Outstanding

	Six Months Ended June 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 on Trust capital pursuant to DRIP	36	67	2,868	17,421
Cancellation of Trust capital pursuant to NCIB	(92)	(892)	-	-
Fair value adjustment	-	-	-	2,319
Trust unit issuance costs	-	-	-	(37)
Ending balance	**34,961**	**316,325**	**35,017**	**317,150**

For the six months ended June 30, 2015, the Trust incurred $nil (December 31, 2014 - $37,099) of unit issuance costs in conjunction with the DRIP.

Commencing with the distribution paid on February 23, 2015 for unitholders of record on January 30, 2015, Eagle's Distribution Reinvestment Plan ("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 six months ended June 30, 2015, the Trust has purchased and cancelled 92,300 units at a weighted average market price of $2.67 per unit pursuant to the NCIB.

13. Accumulated Cash Distributions

$ 000's	**June 30, 2015**	December 31 2014
Beginning balance	(116,315)	(80,454)
Accumulated cash distributions	(6,301)	(33,524)
Fair market value of units issued under the DRIP	18	(2,337)
Total accumulated cash distributions	**(122,598)**	(116,315)

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

14. 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 31 months and approximately $1.3 million remaining at June 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 30 months and approximately $US 0.7 million remaining at June 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 1.25.

15. Subsequent Events

On July 22, 2015, the Trust announced that it has entered into an agreement with a private company (“Privateco”) for the acquisition by Eagle of all the issued and outstanding shares of Privateco (the “Transaction”). The Transaction is valued at approximately $30 million, including Privateco’s indebtedness, and will be funded out of Eagle’s existing credit facility of $US 85 million. It will be completed by the amalgamation of Privateco with a newly incorporated Eagle subsidiary and requires Privateco’s shareholder approval. The Transaction is expected to close by the end of August 2015. Directors, officers and a number of other Privateco shareholders, owning an aggregate of more than two-thirds of Privateco’s shares, have signed support agreements to vote in favor of the Transaction.

Privateco has estimated production of approximately 750 barrels of oil equivalent per day (64% oil and natural gas liquids) from the Twining field in Alberta.

Corporate Information

Board of Directors

David M. Fitzpatrick
Chairman of the Board

Bruce K. Gibson (1)
Director

Warren D. Steckley (2)
Director

Joseph W. Blandford (3)
Director

Richard W. Clark
President, Chief Executive Officer and Director

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

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Officers

Richard W. Clark
President, Chief Executive Officer and Director

Kelly A. Tomyn
Chief Financial Officer

J. Wayne Wisniewski
Chief Operating Officer

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

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