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2015 Financial Report

EAGLE ENERGY™
TRUST

(the predecessor reporting issuer to Eagle Energy Inc.)

(the predecessor reporting issuer to Eagle Energy Inc.)

Management's Discussion and Analysis

March 17, 2016

This Management's Discussion and Analysis ("**MD&A**") of financial condition and results of operations for Eagle Energy Trust (the "**Trust**" or "**Eagle**"), dated March 17, 2016, should be read in conjunction with the Trust's audited consolidated financial statements and accompanying notes for the year ended December 31, 2015 and Eagle's Annual Information Form dated March 17, 2016 ("**AIF**"), which are available online under Eagle's issuer profile at www.sedar.com and on Eagle's website at www.eagleenergy.com.

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

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

The foreign exchange rate at December 31, 2015 was $US 1.00 equal to $CA 1.38 (December 31, 2014 - $US 1.00 equal to $CA 1.16), and the average foreign exchange rate for the year ended December 31, 2015 was $US 1.00 equal to $CA 1.28 (for the year ended December 31, 2014 - $US 1.00 equal to $CA 1.10).

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 US and in Canada.

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

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

Overview of the Trust

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.

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.

On November 20, 2015, Eagle announced that it had entered into an agreement to acquire Maple Leaf Royalties Corp. ("**Maple Leaf**") by way of a plan of arrangement (the "**Arrangement**"). Under the Arrangement, Eagle acquired Maple Leaf and converted into a corporate structure on January 27, 2016.

Highlights for the Year Ended December 31, 2015

Eagle achieved the following results in 2015:

- Acquired assets in the Twining field in Alberta in August 2015 at a total cost of $27.3 million, and established a Canadian based operations team to complement its US based team.

- Continued to manage Eagle in a fiscally prudent manner, with 2015 year-end debt to trailing cash flow of 2.1x and 40% of its $US 80 million facility undrawn.

- Increased year-over-year proved developed producing reserves by 10%, total proved reserves by 14% and total proved plus probable reserves by 16%.

- Grew total proved plus probable reserves to approximately 18.6 million boe (70% proved, 58% proved producing).

- Achieved a total proved reserve replacement ratio of 234% and a total proved plus probable reserve replacement ratio of 307%.

- Executed a drilling program with a 100% success rate.

- Reported average working interest sales volumes of 3,358 barrels of oil equivalent per day ("**boe/d**") (93% oil, 2% natural gas liquids ("**NGLs**") and 5% natural gas). Current working interest production approximates 3,700 boe/d.

- Reported funds flow from operations of $30.4 million ($25.09 per boe or $0.89 per Trust unit).

- On January 27, 2016, the Trust closed the previously announced acquisition of Maple Leaf and conversion into a corporate structure. The resulting entity, Eagle Energy Inc., is listed on the Toronto Stock Exchange. Its common shares trade under the symbol "EGL". The acquisition of Maple Leaf is expected to add approximately 235 boe/d from royalty interest and 161 boe/d from working interest assets in Alberta.

2016 Budget and Outlook

This outlook section is intended to provide shareholders with information about Eagle's expectations for production and capital expenditures for 2016. 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 2016 capital budget of $CA 5.0 million consists of $US 3.0.million for Eagle's operations in the United States and $0.8 million for Eagle's operations in Canada. The 2016 capital budget excludes future corporate and property acquisitions, which are evaluated separately on their own merit.

Eagle's 2016 capital budget, production and operating cost guidance remains unchanged from what Eagle previously announced on February 11, 2016:

	2016 Guidance	Notes
Capital Budget	$5.0 mm	1
Working Interest Production	3,200 to 3,600 boe/d	2
Operating Costs per month	$2.2 to $2.6 mm	

Notes:

(1) The 2016 capital budget of $CA 5.0 million consists of $US 3.0.million for Eagle's operations in the United States and $0.8 million for Eagle's operations in Canada. At an assumed $US 40.00 per barrel WTI oil price, Eagle's 2016 capital budget of $5.0 million and dividend of $0.01 per common share of Eagle per month ($0.12 per share annualized) results in a corporate payout ratio of 93%.

(2) 2016 production is forecast to consist of 87% oil, 10% natural gas and 3% NGLs. These numbers are working interest production numbers only and exclude 235 boe/d of royalty interest volumes from the acquisition of Maple Leaf that was completed on January 27, 2016.

Eagle's Funds Flow from Operations and Corporate Payout Ratio

A strengthening in the Canadian dollar has prompted a change in the foreign exchange rate assumptions. Refer to the table titled "Sensitivity to Commodity Price", below.

As a result of the change in the foreign exchange rate assumption, Eagle's funds flow from operations and corporate payout ratio are calculated as follows:

	Amount	Notes
Funds Flow from Operations	$10.8 mm	(1)
Basic Payout Ratio	48%	(2)
Plus: Capital Expenditures	45%	
Equals: Corporate Payout Ratio	93%	(3)

Notes:

(1) 2016 funds flow from operations is expected to be approximately $CA 10.8 million based on the following assumptions:

- (a) average working interest production of 3,400 boe/d (the mid-point of the guidance range);
- (b) pricing at $US 40.00 per barrel WTI oil, $US 3.16 per Mcf NYMEX gas, $CA 2.57 per Mcf AECO and $US 14.00 per barrel of NGL (NGL price is calculated as 35% of the WTI price);
- (c) differential to WTI is $US 3.10 discount per barrel in Salt Flat, $US 3.50 discount per barrel in Hardeman, $CA 16.17 discount per barrel in Dixonville and $CA 12.67 discount per barrel in Twining;
- (d) average operating costs of $CA 2.4 million per month ($US 0.9 million per month for Eagle's operations in the United States and $CA 1.2 million per month for Eagle's operations in Canada), the mid-point of the guidance range;
- (e) foreign exchange rate of $US 1.00 equal to $CA 1.33 (previously $CA 1.40); and
- (f) field netback (excluding hedges) of $10.56 per boe.

(2) Eagle calculates its Basic Payout Ratio as follows:

$$\frac{\text{Shareholder Dividends}}{\text{Funds Flow from Operations}} = \text{Basic Payout Ratio}$$

(3) Eagle calculates its Corporate Payout Ratio as follows:

$$\frac{\text{Capital Expenditures + Shareholder Dividends}}{\text{Funds Flow from Operations}} = \text{Corporate Payout Ratio}$$

(4) Funds flow from operations, basic payout ratio and corporate payout ratio are non-IFRS measures. See the section titled "Non-IFRS Financial Measures".

The following tables show the sensitivity of Eagle's 2016 funds flow from operations, corporate payout ratio and debt to trailing cash flow to changes in commodity prices, exchange rates and production:

Sensitivity to Commodity Price	2016 Average WTI (Production 3,400 boe/d)		
	$US 35 (FX 1.38)	$US 40 (FX 1.33)	$US 45 (FX 1.28)
Funds Flow from Operations ($CA)	$10.3	$10.8	$10.8
Corporate Payout Ratio	99%	93%	92%
Debt to Trailing Cash Flow	6.4x	6.0x	6.0x

Sensitivity to Production	2016 Average Production (boe/d) (WTI $US 40, F/X 1.33)		
	3,200	**3,400**	**3,600**
Funds Flow from Operations ($CA)	$10.0	$10.8	$11.5
Corporate Payout Ratio	101%	93%	87%
Debt to Trailing Cash Flow	6.6x	6.0x	5.6x

Assumptions:

(1) Annualized dividends are assumed to be $0.12 per share per year.

(2) Operating costs are assumed to be $2.4 million per month (mid-point of guidance range).

(3) Differential to WTI held constant.

(4) Foreign exchange rate is assumed to be $US 1.00 equal to $CA 1.33 unless otherwise indicated in the table.

Sensitivities

Eagle'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]	$US 0.10/mcf Henry HUB	21	-
Oil price[2]	$US 1.00/bbl WTI	280	0.01
Gas production	+1000 mcf/d	125	-
Oil production	+100 bbls/d	156	-
Currency[2]	+CA weaken by $0.01	40	-
Interest rate	+1% prime	(129)	-

Notes:

(1) Per unit figures are based on 34,961,092 weighted average basic units outstanding for the twelve months ended December 31, 2015.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate of 3,376 boe/d.

Operations Update

Eagle's operational focus in 2015 was to maximize field cashflow. Well reviews were performed on all wells with the objective of reducing operating costs. As a result, operating costs have been reduced by more than 40% at the Hardeman assets in North Texas and Oklahoma since Eagle assumed operatorship of these assets two years ago. The biggest portion of the operating expense reduction has been in water disposal costs, particularly in the southern operating area where a salt water disposal system was installed in September 2015. The project required electrification in the southern area which, in addition to powering the salt water disposal facility, will ultimately help improve run time and reduce propane charges in that part of the field.

At Salt Flat, Eagle continued to focus on operational efficiencies, achieving a 10% year-over-year per boe cost reduction for the past three years. Eagle produces over 100,000 barrels of water per day at Salt Flat, making it necessary to effectively and efficiently handle large volumes of produced water.

During 2015, Eagle established an operating presence in Canada as a result of the acquisition of the Dixonville properties at the end of 2014 and the Twining properties in August 2015. Production during the fourth quarter of 2015 was split evenly between the US and the Canadian properties. Eagle's operations team based in Calgary manages these properties and continues to examine operational efficiencies. Utilizing well-by-well review and internally developed cost reduction processes, Eagle reduced per barrel operating costs by 14% at Twining during the first four months operating the properties.

Eagle successfully drilled seven wells (including one salt water disposal well) in 2015, with capital spending and production within stated guidance. Three horizontal wells were drilled at Salt Flat, with first year production and estimated ultimate recovery from these three wells exceeding results from Eagle's previous drilling program in the area. At Hardeman, four vertical wells were drilled, one of which was the salt water disposal well.

Eagle produced an average of 3,358 boe/d, with Eagle's operated properties outperforming plans, in particular at Salt Flat. Dixonville (where Eagle has a 50% non-operated working interest) was below planned production due to two major field gathering lines not being re-activated. Eagle was able to replace the Dixonville production shortfall with Salt Flat barrels that had a significantly higher netback, resulting in higher corporate cashflow. As well, volumes in the fourth quarter included an average of 690 boe/d from the Twining acquisition.

Eagle achieved a 234% total proved reserves replacement ratio and made meaningful improvements to per boe netbacks through negotiating more favorable marketing contracts, decreasing general and administrative costs by thoughtful outsourcing of certain functions and undertaking targeted business process improvements.

Year-end Reserves Information

Eagle targets low risk, producing properties with development potential, and maintains or grows production by converting the non-producing portion of those assets into producing assets, thereby sustaining cash flow and dividends.

An independent evaluation of the Trust's US reserves was conducted by Netherland, Sewell & Associates, Inc. and of the Trust's Canadian reserves by McDaniel & Associates Consultants Ltd. These reserves evaluation reports are effective December 31, 2015 and were prepared in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Details regarding the Trust's reserves and oil and gas assets are set forth in Eagle's AIF.

2015 Year-End Reserves Report - Highlights

- Increased year-over-year proved developed producing reserves by 10%, total proved reserves by 14% and total proved plus probable reserves by 16%.
- Grew total proved plus probable reserves to approximately 18.6 million boe (70% proved, 58% proved producing).
- 94% of the proved developed producing reserves are light oil.
- Achieved total proved plus probable finding, development and acquisition costs (including changes in future development costs) of $14.02 per boe.
- Maintained Eagle's proved plus probable reserve life index above 14 years and replaced 234% of its reserves on a proved basis.

The following tables summarize the independent reserves estimates and values of Eagle's reserves as at December 31, 2015:

Summary of Reserves

Canadian Operations	**Company Gross[1]**				
Reserves Categories	**Crude Oil**	**Natural Gas Liquids**	**Natural Gas**	**Total Oil Equivalent 2015**	**Total Oil Equivalent 2014**
	(Mbbls)	(Mbbls)	(MMcf)	(Mboe)	(Mboe)
Proved					
Developed producing	7,683	62	3,010	8,247	7,182
Developed non-producing	61	10	410	139	-
Undeveloped	581	26	1,082	787	159
Total proved	8,325	98	4,502	9,173	7,341
Total probable	3,635	64	2,853	4,174	2,877
Total proved plus probable	11,960	162	7,355	13,347	10,217

US Operations	**Company Gross[1]**				
Reserves Categories	**Crude Oil**	**Natural Gas Liquids**	**Natural Gas**	**Total Oil Equivalent 2015**	**Total Oil Equivalent 2014**
	(Mbbls)	(Mbbls)	(MMcf)	(Mboe)	(Mboe)
Proved					
Developed producing	2,404	53	266	2,501	2,591
Developed non-producing	324	11	76	348	397
Undeveloped	998	4	27	1,007	1,052
Total proved	3,726	68	369	3,856	4,040
Total probable	1,350	4	26	1,358	1,748
Total proved plus probable	5,077	71	395	5,214	5,788

Total Company Operations	**Company Gross[1]**				
Reserves Categories	**Crude Oil**	**Natural Gas Liquids**	**Natural Gas**	**Total Oil Equivalent 2015**	**Total Oil Equivalent 2014**
	(Mbbls)	(Mbbls)	(MMcf)	(Mboe)	(Mboe)
Proved					
Developed producing	10,087	115	3,277	10,748	9,773
Developed non-producing	385	21	486	487	397
Undeveloped	1,579	30	1,109	1,793	1,212
Total proved	12,051	165	4,871	13,028	11,381
Total probable	4,985	68	2,879	5,533	4,624
Total proved plus probable	17,037	233	7,750	18,561	16,006

Notes:

(1) Company gross reserves are Eagle's total working interest share before the deduction of any royalties and without including any of Eagle's royalty interests.

(2) Totals may not add due to rounding.

Summary of Net Present Value of Future Net Revenue of Reserves

Canadian Operations	**Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)**				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
$CA	($000's)	($000's)	($000's)	($000's)	($000's)
Proved					
Developed producing	239,819	141,693	95,665	70,945	56,086
Developed non-producing	2,595	2,003	1,534	1,193	948
Undeveloped	13,474	7,493	4,165	2,171	900
Total proved	255,887	151,189	101,365	74,309	57,934
Total probable	163,567	59,240	29,713	18,377	12,788
Total proved plus probable	419,454	210,429	131,078	92,685	70,721

US Operations	**Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)**				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
$US	($000's)	($000's)	($000's)	($000's)	($000's)
Proved					
Developed producing	60,908	43,721	35,481	30,463	26,984
Developed non-producing	11,626	7,456	5,345	4,126	3,339
Undeveloped	22,634	18,702	15,629	13,189	11,224
Total proved	95,168	69,879	56,455	47,777	41,548
Total probable	40,239	29,168	21,717	16,560	12,900
Total proved plus probable	135,407	99,047	78,172	64,338	54,447

Total Company Operations	**Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)**				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
$CA	($000's)	($000's)	($000's)	($000's)	($000's)
Proved					
Developed producing	316,511	197,398	141,247	110,324	91,144
Developed non-producing	16,851	11,183	8,138	6,305	5,092
Undeveloped	41,500	30,664	23,535	18,519	14,814
Total proved	374,862	239,245	172,920	135,148	111,049
Total probable	212,625	94,847	56,261	38,651	28,605
Total proved plus probable	587,487	334,092	229,181	173,799	139,655

Notes:

(1) It should not be assumed that the net present values of estimated future net revenue shown above are representative of the fair market value of the reserves. There is no assurance that the underlying price and costs assumptions will be attained and variances could be material. The recovery and 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.

(2) The US operations numbers have been converted into Canadian dollars using the following foreign exchange rates: 2016 - $CA 1.00 equal to $US 0.730; 2017 - $CA 1.00 equal to $US 0.750; 2018 - $CA 1.00 equal to $US 0.800; 2019 - $CA 1.00 equal to $US 0.800; 2020 and thereafter - $CA 1.00 equal to $US 0.825 (as per McDaniel & Associates Consultants Ltd. January 1, 2016 price deck forecast).

At a 10% discount factor, proved developed producing reserves comprise 61% (2014 – 65%) of the total proved plus probable value. Total proved reserves account for 75% (2014 – 78%) of the total proved plus probable value.

Future Development Cost ("FDC")

Total future development costs are estimated at $30.4 million for total proved and $46.6 million for total proved plus probable reserves. When compared to 2016 funds flow guidance of $10.8 million (based on $US 40 WTI oil price and a foreign exchange rate of $US 1.00 equal to $CA 1.33), future development costs represent 2.8 years and 4.3 years of funds flow, respectively.

Reserves Performance Ratios

During 2015, Eagle's capital expenditures, including acquisition capital, resulted in capital efficiency statistics as shown in the following table. Statistics which cannot be meaningfully calculated are shown as a dashed line.

	2015		2014	
	Proved	**Proved plus Probable**	**Proved**	**Proved plus Probable**
Reserves (Mboe)	13,028	18,561	11,381	16,006
Capital Expenditures ($M)				
Exploration and Development (E&D)[(1)]	14,134	14,134	13,037	13,037
Acquisition[(2)]	30,970	30,970	106,319	106,319
Disposition[(2)]	-	-	(150,141)	(150,141)
Disposition (related E&D)	-	-	11,286	11,286
Total Capital Expenditures	45,104	45,104	(19,500)	(19,500)
Field Netbacks ($/boe)[(3)]				
Current Year	19.30	19.30	49.75	49.75
Finding, Development and Acquisition Costs[(5)]				
Change in future development capital ($M)	8,652	8,006	11,535	18,865
Reserve additions (Mboes)	2,880	3,788	8,529	11,517
FD&A Costs including changes in FDC ($/boe)[(5)]	18.66	14.02	15.35	12.00
FD&A Costs excluding changes in FDC ($/boe)[(5)]	15.66	11.91	13.99	10.36
FD&A Recycle Ratio[(4)]	1.03	1.38	3.24	4.15
Reserves replacement[(6)]	234%	307%	145%	265%
Reserves life index (yrs)[(7)]	10.4	14.9	10.2	14.4

Notes:

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

(2) Acquisition relates to the August 2015 acquisition in Twining and the December 2014 acquisition of Dixonville. Disposition relates to the August 2014 divestiture of the Permian properties.

(3) Field netbacks are calculated by subtracting royalties and operating costs from revenues.

(4) The recycle ratio is calculated using Eagle's 2015 field netback of $19.30 per boe (2014 - $49.75 per boe) and dividing that number by finding, development and acquisition ("**FD&A**") costs per boe.

(5) Eagle calculates FD&A costs, incorporating both the costs and associated reserve additions related to development capital and acquisitions during the year.

(6) The reserves replacement ratios are calculated by dividing total reserve additions by total working interest production for the year.

(7) The 2015 reserve life index calculation is based on the mid-point of Eagle's 2016 average working interest production guidance of 3,400 boe/d and the 2014 reserve life index calculation was based on 3,050 boe/d.

Selected Annual Information

The following table shows selected information for the Trust's fiscal year ended December 31, 2015, December 31, 2014 and December 31, 2013.

Year ended December 31	2015	2014	2013
($000's except per Trust unit amounts and production)			
Sales volumes – boe/d	3,358	2,782	3,004
Revenue, net of royalties	48,121	67,175	69,210
Field netback	23,659	50,522	57,260
Funds flow from operations	30,738	33,958	44,271
per unit – basic	0.88	1.01	1.44
per unit - diluted	0.88	1.00	1.44
Earnings (loss)	(76,046)	(48,028)	4,914
per unit – basic	(2.18)	(1.43)	0.16
per unit - diluted	(2.18)	(1.55)	0.16
Current assets	19,767	33,245	9,889
Current liabilities	9,397	10,720	30,461
Total assets	208,572	257,172	335,679
Total non-current liabilities	92,616	57,547	70,521
Unitholders' equity	106,559	188,905	234,697
Distributions declared	12,040	33,524	32,434
per issued unit	0.35	0.99	1.05
Units issued	34,863	35,017	32,149

Consolidated Results of Operations

Production

	Three Months Ended December 31, 2015	Three Months Ended December 30, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Oil (bbl/d)	3,345	1,815	84	3,131	2,357	33
Natural gas (Mcf/d)	1,966	296	564	918	1,226	(25)
Natural gas liquids (bbl/d)	110	65	69	74	221	(67)
Oil equivalent sales volumes (boe/d @ 6:1)	**3,783**	1,929	96	**3,358**	2,782	21

Working interest sales volumes for the year ended December 31, 2015 averaged 3,358 boe/d (93% oil, 2% NGLs, 5% natural gas).

Revenue

$000's	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Oil	14,322	13,778	4	60,984	86,867	(30)
Natural gas	452	90	402	867	1,978	(56)
Natural gas liquids	154	76	103	461	2,999	(85)
Other	294	128	130	1,000	569	76
Sales before royalties	**15,222**	14,072	8	**63,312**	92,413	(31)

Realized prices						
Oil ($/bbl)	46.53	82.51	(44)	53.36	100.99	(47)
Natural gas ($/Mcf)	2.50	3.32	(25)	2.59	4.42	(41)
Natural gas liquids ($/bbl)	15.28	12.70	20	17.15	37.16	(54)
Other ($/bbl)	0.85	0.72	18	0.82	0.56	46
Sales before royalties ($/boe)	43.74	79.28	(45)	51.66	91.01	(43)
Royalties ($/boe)	(10.40)	(21.61)	(52)	(12.40)	(24.86)	(50)
Revenue ($/boe)	**33.34**	57.67	(42)	**39.27**	66.15	(41)

Benchmark prices[(1)] in $CA						
Oil – WTI ($/bbl)	**53.94**	73.15	(26)	**62.40**	93.00	(33)
Natural gas – Henry HUB ($/Mcf)	**2.86**	3.85	(26)	**3.36**	4.28	(21)

Notes:

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

The Trust's quarterly revenue is 95% derived from oil. For the three months ended December 31, 2015, sales before royalties increased by 8% when compared to the prior year's comparative period. For the year ended December 31, 2015, sales revenue decreased by 31% when compared to the year ended December 31, 2014. Although year-over-year production increased by 21% due to the acquisitions in the Canadian segment, revenues decreased primarily due to the 47% decline year-over-year in realized oil prices, which trended with the decline in the WTI price.

For Eagle's US properties, 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 predictable pricing. Management monitors pricing regularly and endeavours to maximize realized sales prices while minimizing counterparty risk. For the Salt Flat properties, the field marketing contracts use Louisiana Light Sweet ("LLS") as a benchmark reference price instead of WTI. For the period July 1, 2015 to November 30, 2015, Eagle negotiated a new contract which improved the fixed field pricing adjustment by $US 1.75 per barrel, while continuing to allow the LLS-WTI differential and the Argus P+ differential to float. Commencing December 1, 2015, this contact is on a month to month term and the fixed pricing adjustment was improved by an additional $US 1.00 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 entire differential to WTI, including quality and transportation, is approximately $CA 16.17 discount per barrel, but fluctuates. For the Twining properties in Canada, the entire differential to WTI, including quality and transportation, is approximately $CA 12.67 discount per barrel, but fluctuates. On October 1, 2015, to mitigate the effect of fluctuating differentials on a portion of its production, the Trust entered into a fixed price financial swap on 1,000 barrels per day of oil fixing the price differential between Edmonton light sweet and WTI at $US 3.65 per barrel for the period December 1, 2015 to December 31, 2016. The portion of the differential between Edmonton light sweet and realized field price was not fixed in this transaction. The differential was hedged at a narrower amount than the historical WTI to Edmonton light sweet differential has been.

The above prices do not include realized gains or losses from financial commodity contracts, which amounted to a gain of $4.0 million ($11.54/boe) for the three months ended December 31, 2015 and a gain of $20.7 million ($16.90

per boe) for the twelve months ended December 31, 2015. See "Realized and Unrealized Risk Management Gain/Loss".

Royalties

	Three Months Ended December 31, 2015	Three Months Ended December 30, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Royalties ($000's)	3,619	3,835	(6)	15,191	25,238	(40)
Royalties ($/boe)	**10.40**	21.61	(52)	**12.40**	24.86	(50)
Percentage of sales:	**24%**	27%	(13)	**24%**	27%	(12)

The overall royalty rate for both the three and twelve months ended December 31, 2015 of 24% is slightly lower than the prior year's comparative period's royalty rate of 27% 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 traded lower since December 31, 2014, causing a downward trend in Alberta Crown royalty rates.

Operating Costs

$000's	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Operating costs	5,640	3,357	68	22,108	16,062	38
Transportation and marketing expenses	716	39	1,736	2,354	592	298
	6,356	2,396	165	**24,462**	16,654	47
Operating costs ($/boe)	16.21	18.91	(14)	18.04	15.82	14
Transportation and marketing expenses ($/boe)	2.06	0.23	795	1.92	0.58	231
($/boe)	**18.26**	19.13	(5)	**19.96**	16.40	22

Operating costs for the three months ended December 31, 2015 are comprised primarily of power (15%), oil transportation (9%), water disposal fees (6%), chemicals (5%) and field salaries (4%). Operating costs for the year ended December 31, 2015 are comprised primarily of power (16%), oil transportation (9%), water disposal fees (8%), chemicals (8%) and field salaries (8%).

The operating expense increase of 38% for the twelve months ended December 31, 2015 versus 2014 is due in part to the acquisition of properties in Dixonville and Twining, Alberta. As well, the change in the foreign exchange rate increased the amount of the US dollar operating costs reported in Canadian dollars by approximately 16%.

Fourth quarter operating expenses on a per barrel basis were lower than third quarter levels due to workover and turnaround costs in the Twining area in the third quarter. The Trust continues to improve operating efficiencies and maintains its 2016 operating expense guidance of $2.2 to $2.6 million per month. Refer to the "Segmented Operations" and "2016 Budget and Outlook" sections of this MD&A.

Oil Transportation Expenses

For the three and twelve months ended December 31, 2015, transportation and marketing expenses are higher than in the previous year due to trucking costs for the majority of its production on the Dixonville and Twining properties. The transportation costs for the US wells remained consistent at approximately $0.23/boe for the US properties.

Depreciation, Depletion, Amortization and Impairment

$000's	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Depreciation, depletion and amortization	6,021	7,236	(17)	26,396	35,846	(26)
Impairment	25,980	49,604	(48)	87,255	69,685	25
Total depreciation, depletion, amortization and impairment	**32,001**	56,840	(44)	**113,651**	105,531	(8)

Depletion, Depreciation and Amortization

The depletion, depreciation, and amortization provision for the three months and year ended December 31, 2015 was based on proved plus probable reserves, including the future development costs associated with those reserves, as outlined in the year-end 2015 reserves evaluation report prepared by the Trust's independent reserves evaluators.

The disposition of the Permian properties in Martin County, Texas in 2014 and the acquisition of the Dixonville and Twining properties in Alberta significantly changed the nature of Eagle's asset base. Forecast corporate decline rates have dropped from approximately 30% to under 20%, with the result being a significant reduction in required sustaining capital and lower future development costs associated with the reserves. As commodity prices recover, it is anticipated that the amount of cash remaining after funding sustaining capital requirements will rise on a relative percentage basis.

In Dixonville, a combination of the decrease in carrying value due to a third quarter impairment charge, along with a slight increase in reserves, resulted in a lower per boe depletion rate from $11.43 to $9.01 per boe. The fourth quarter was the first full quarter for the Twining assets, which recorded a depletion rate of $14.59 per boe.

In Hardeman a decrease in carrying value due to a third quarter impairment, partially offset by a slight decrease in reserves, resulted in a per boe depletion rate of $ 15.45 in the fourth quarter compared to $ 18.51 in the third quarter. In Salt Flat, the carrying value decreased significantly due to a third quarter impairment. Reserves stayed relatively the same, but the per boe rate dropped from $ 25.83 per boe in the third quarter to $ 17.23 in the fourth quarter of 2015.

Depletion during the fourth quarter of 2014 included the US properties only. The Hardeman rate for the fourth quarter of 2014 was $18.60 per boe, while Salt Flat was $41.29 per boe.

Impairment

United States - Salt Flat and Hardeman Cash Generating Units

As a result of the current price environment, the Trust's US assets were assessed for impairment at December 31, 2015. The fair value was calculated by taking the net present value of the after tax cash flows from its oil and gas proved plus probable reserves as estimated by the third party reserve evaluators. A risk-adjusted discount rate of 11% (2014 – 10%) was used for both areas and a WTI price of $US 45.00 in 2016, $US 53.60 in 2017, $US 62.40 in 2018, $US 69.00 in 2019, $US 73.10 in 2020, $US 77.30 in 2021, $US 81.60 in 2022, $US 86.20 in 2023, $US 87.90 in 2024, $US 89.60 for 2025, $US 91.40 and +2%/year for the remainder. Based on the analysis, the Trust recorded an impairment provision of $US 2.1 million in the Salt Flat cash generating unit and $nil in the Hardeman cash generating unit for the three months ended December 31, 2015 (2014 - $49.2 million and $nil respectively).

Total impairment for the year ended December 31, 2015 was $US 23.0 million in Salt Flat and $US 8.1 in Hardeman, compared to $US 49.2 million in Salt Flat in 2014 and $nil in Hardeman in 2014. To calculate the impairment for the year, the fair value less costs to dispose of the assets for each CGU was estimated and then compared to the net book value for each CGU. The Salt Flat CGU was written down to its recoverable amount of $US 32.6 million based on the fair value less costs to dispose, and the Hardeman asset was valued at $US 29.6 million. The fair value was calculated by taking the net present value of the after tax cash flows from its oil and gas proved plus probable reserves as estimated by the third party reserve evaluators, discounted at a rate of 11% (compared to a discount rate of 10% in the prior year). An improvement in reserve estimates or commodity pricing could reverse any impairment charges recorded (after accounting for depletion and depreciation charges otherwise applicable). The remaining impairment charge of $US 20.3 million in 2014 related to the sale of the Permian property assets on August 29, 2014 as the disposition proceeds were less than the book value of the Permian CGU. The 2015 impairment was primarily the result of the decrease in forecast benchmark commodity prices at December 31, 2015 compared to December 31, 2014, along with an increase in the discount rate.

The calculation of the recoverable amount is sensitive to the assumptions regarding production volumes, discount rates and commodity prices. A 1% increase (decrease) in the discount rate would have decreased (increased) the fair value estimate in the Salt Flat CGU by approximately $US 1.8 million and in the Hardeman CGU by approximately $US 2.4 million. In addition, a 10% increase (decrease) in the estimated future cash flows would have increased (decreased) the fair value estimate by $US 4.6 million in Salt Flat and $US 8.3 million in Hardeman.

Canada – Dixonville and Twining Cash Generating Units

As a result of the current price environment, the Trust's Canadian assets were assessed for impairment at December 31, 2015. The fair value was calculated by taking the net present value of the after tax cash flows from its oil and gas proved plus probable reserves as estimated by the third party reserve evaluators. A risk-adjusted discount rate of 11.6% was used for Dixonville and 11% for Twining, and a WTI price of $US 45.00 in 2016, $US 53.60 in 2017, $US 62.40 in 2018, $US 69.00 in 2019, $US 73.10 in 2020, $US 77.30 in 2021, $US 81.60 in 2022, $US 86.20 in 2023, $US 87.90 in 2024, $US 89.60 for 2025, $US 91.40 and +2%/year for the remainder was used for both areas. Based on the analysis, the Trust recorded an impairment provision of $ 14.5 million in the Dixonville CGU and $ 8.2 million in the Twining CGU for the three months ended December 31, 2015.

Total impairment for the year ended December 31, 2015 was $39.2 million in Dixonville and $8.2 in Twining. To calculate the impairment for the year, the fair value less costs to dispose of the assets for each CGU was estimated and then compared to the net book value for each CGU. The Dixonville CGU was written down to its recoverable amount of $69.6 million based on the fair value less costs to dispose, and the Twining asset was valued at $27.4 million. The fair value was calculated by taking the net present value of the after tax cash flows from its oil and gas proved plus probable reserves as estimated by the third party reserve evaluators, discounted at a rate of 11.6% in Dixonville and 11.0% in Twining. An improvement in reserve estimates or commodity pricing could reverse any impairment charges recorded (after accounting for depletion and depreciation charges otherwise applicable). The impairment for the year was primarily the result of the decrease in forecast benchmark commodity prices at December 31, 2015 compared to December 31, 2014.

The calculation of the recoverable amount is sensitive to the assumptions regarding production volumes, discount rates and commodity prices. A 1% increase (decrease) in the discount rate would have decreased (increased) the fair value estimate in the Dixonville CGU by approximately $6.9 million and in the Twining CGU by approximately $2.0 million. In addition, a 10% increase (decrease) in the estimated future cash flows would have increased (decreased) the fair value estimate by $7.8 million in Dixonville and $2.9 million in Twining.

Field Netback

	Three Months Ended December 31, 2015		**Three Months Ended December 31, 2014**		**Year Ended December 31, 2015**		**Year Ended December 31, 2014**	
$000's		**$/boe**		$/boe		**$/boe**		$/boe
Sales before royalties	15,222	43.74	14,072	79.28	63,312	51.66	92,413	91.01
Royalties	(3,619)	(10.40)	(3,835)	(21.61)	(15,191)	(12.40)	(25,238)	(24.86)
Operating expenses	(5,640)	(16.21)	(3,357)	(18.91)	(22,108)	(18.04)	(16,062)	(15.82)
Transportation and marketing expenses	(716)	(2.06)	(39)	(0.23)	(2,354)	(1.92)	(592)	(0.58)
Field netback	**5,247**	**15.07**	6,841	38.53	**23,659**	**19.30**	50,521	49.75
Sales volumes (boe/d)		**3,783**		1,929		**3,358**		2,782

During the quarter, the Trust's realized price was $43.74 per boe and the field netback was $15.07 per boe. For the twelve months ended December 31, 2015, the realized price was $51.66 per boe and the field netback was $19.30. When compared to the prior year, the decrease in field netback is primarily due to the sharp drop in commodity prices, partially offset by lower royalty rates as a result of additional production in Canada which is subject to price sensitive sliding-scale royalties. Refer to the "Segmented Operations" section of this MD&A.

Field netback is a non-IFRS 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:

Commodity:

	Volume	Measure	Beginning	Term	Price $US
Oil Fixed Price					
NYMEX (i)	500	bbls/d	Jan-16	Dec-16	65.00
NYMEX (i)	500	bbls/d	Jan-16	Dec-16	53.32
NYMEX (i)	300	bbls/d	Mar-16	Jul-16	36.00
NYMEX (i)	200	bbls/d	Mar-16	Jul-16	37.25
NYMEX (i)	400	bbls/d	Aug-16	Dec-16	40.05
NYMEX (i)	300	bbls/d	Aug-16	Dec-16	40.27
NYMEX (i)	375	bbls/d	Jan-17	Dec-17	45.10
NYMEX (i)	375	bbls/d	Jan-17	Dec-17	44.75
Gas Fixed Price					
CGPR ALT daily spot	1500	GJs/day	Jan-16	Dec-16	2.83

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

$000's	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Realized gain (loss) - Commodity	4,017	3,264	23	20,714	302	6,759
Unrealized gain (loss) - Commodity	397	13,109	(97)	(7,962)	15,718	(151)
Net gain (loss) - Commodity	4,414	16,373	(73)	12,752	16,020	(20)
Realized gain (loss) - Foreign exchange	-	(111)	(100)	-	(153)	(100)
Unrealized gain (loss) - Foreign exchange	-	81	(100)	-	-	-
Net gain (loss) - Foreign exchange	-	(30)	(100)	-	(153)	(100)
Total net gain (loss)	**4,414**	16,343	(73)	**12,752**	15,867	(20)

At December 31, 2014, the Trust had 1,990 boe/day hedged at an average floor price of $89.29. These amounts were recorded as an unrealized gain at December 31, 2014. During the year the contracts were paid out and booked as a realized gain. 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 the 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.

As of the date of this MD&A, Eagle has fixed price financial swap transactions for 2016 with a weighted average forward sale price of $US 52.30 WTI per barrel on 1,506 barrels of oil per day and fixed price financial swap transactions for 2017 with a weighted average forward sale price of $US 45.00 WTI per barrel on 750 barrels of oil per day. In addition, Eagle has a natural gas hedge on 1,500 GJs per day at a fixed price of $CA 2.83 per GJ for the period January 1, 2016 to December 31, 2016.

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

Finance Expense

	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Finance expense ($000's)	**864**	279	210	**2,973**	2,655	12
($/boe)	**2.16**	1.57	38	**2.43**	2.61	(7)

Total finance expense for the three months ended December 31, 2015, increased over prior year's comparative quarter due to the increase of the Trust's outstanding advances on its credit facility and an increase in the accretion of the decommissioning provision due to the property acquisitions in 2015.

For the year ended December 31, 2015, the total finance expense increased over the prior year's comparative period due to the increase of the accretion of the decommissioning provision.

As of December 31, 2015, the effective interest rate on bank debt for the period was 3.3% compared to 3.2% for the comparable period in 2014. During 2015, the Trust borrowed by way of banker's acceptance (funds drawn were denominated in Canadian dollars), which was lower than the prime rate option of borrowing.

Administrative Expenses

	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Administrative expenses ($000's)	**3,514**	3,778	(7)	**11,199**	13,564	(17)
($/boe)	**10.10**	21.34	(53)	**9.14**	13.36	(32)

Total administrative expenses for the three months ended December 31, 2015 were $3.5 million, a decrease of 7% from the comparative period in 2014. For the twelve months ended December 31, 2015, total administrative expenses were $11.2 million, a 17% decrease from $13.6 million for the year ended December 31, 2014. Staff and related employment costs, office costs and one-time deal transaction costs related to the acquisition of a private company (refer to the "Business Combination" section of this MD&A) accounted for 66%, 13% and 11% respectively of administrative expenses for the twelve months ended December 31, 2015.

Unit Based Compensation

$000's	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Unit-based compensation expense (recovery)	**(525)**	(2,714)	(81)	**(882)**	(7,600)	(88)

A non-cash unit-based compensation recovery of $0.9 million was recorded for the year ended December 31, 2015, compared to a recovery of $7.6 million for the year ended December 31, 2014. The change was due to a year-over-year decrease in the unit price, an increase in unit price volatility and a decrease in the risk free rate used in the calculation.

The dollar amount of unit-based compensation expense does not represent cash paid by the Trust. However, the Trust is required to re-determine the fair value of the liability each quarter relating to: (1) the restricted unit rights; (2) the options and (3) the unit rights. Any changes in fair value are recorded as an expense or recovery.

From one reporting period to the next, changes in the closing price of the units, risk free rate and expected future unit price volatility will increase or decrease the fair values of the unit-based awards as calculated under the Black-Scholes valuation model. These fair value changes cause corresponding swings in the amount recorded in the income statement. For the year ended December 31, 2015, the recorded recovery was due to a decrease in the year to date price of the Trust's units. The weighted average exercise price of the unit options of $5.54 remains significantly above the December 31, 2015 closing unit price of $1.14.

During the fourth quarter, $0.04 million was paid out in cash for amounts related to vested restricted unit rights and $0.2 million was recorded for the year ended December 31, 2015 (three and twelve months ended December 31, 2014 - $0.2 million and $0.7 million, respectively). The decrease in payments year over year is due to the reduction in Eagle's monthly cash distribution. Commencing with the distribution paid on January 23, 2015, the Trust took action to protect its balance sheet in light of then current and expected commodity prices and lowered its monthly distribution from $0.0875 to $0.03 per unit per month. Beginning with the distribution declared for December 2015, the Trust reduced the monthly distribution from $0.03 per unit per month to $0.015 per unit per month. With ongoing price weakness, the Trust lowered its distribution level again in February 2016 to $0.01 per month ($0.12 per year annualized).

Tax Horizon

The tax horizon, as determined from a full cycle corporate model incorporating cash flows from the year end reserves evaluation report plus all applicable Canadian and U.S. deductions, indicates that no material corporate Canadian or U.S. taxes are expected to be payable in respect of income attributable to Eagle's properties for several years. The Trust may be subject to state taxes (Texas) or an alternative minimum tax depending on the deductibility of certain capital expenditures. The Texas state tax and alternative minimum tax rates are at 0.95% and 20%, respectively. In the case of alternative minimum tax any amount paid can offset any future corporate tax payable. These taxes are not expected to be material.

The Trust is a "SIFT trust" within the meaning of the *Income Tax Act* (Canada) (the "Tax Act") and as a SIFT trust, the Trust is taxable only on income that: (i) constitutes "non-portfolio earnings" (within the meaning of the Tax Act); or (ii) is not distributed or distributable to the Unitholders. The Trust's indirect Canadian investments are not anticipated to give rise to any "non-portfolio earnings" since the only income the Trust is expected to receive from the Canadian operations will be in the form of returns of capital or taxable dividends from its Canadian subsidiary. As taxable dividends are paid out of the subsidiary's after-tax corporate income, SIFT tax is not anticipated to apply to the Trust or its affiliates (consistent with the policy behind the SIFT tax regime). The Trust has distributed and will continue to distribute all of its taxable income to the Unitholders. As a consequence, it is not anticipated that the Trust will be subject to any Canadian federal income tax.

As at December 31, 2015, the Trust held "taxable Canadian property" (as defined in the Tax Act), as was subject to certain limits on non-resident ownership, and the trust indenture provided certain powers to the trustee in relation thereto.

On January 27, 2016, the Trust closed the previously announced plan of arrangement and converted into a corporate structure. Refer to the "Plan of Arrangement" section of this MD&A.

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 indirect 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 year ended December 31, 2015, the Trust recorded a foreign exchange gain of $14.7 million in relation to this intercompany loan.

Summary of Quarterly Results

	Q4/2015	Q3/2015	Q2/2015	Q1/2015	Q4/2014	Q3/2014	Q2/2014	Q1/2014
($000's except for boe/d and per unit amounts)								
Sales volumes – boe/d	3,783	3,607	3,034	2,995	1,929	2,859	3,341	3,010
Revenue, net of royalties	11,603	13,428	12,884	10,206	10,238	17,143	20,821	18,973
per boe	33.34	40.46	46.66	37.86	57.67	65.19	68.48	70.04
Field netback	5,246	6,956	7,713	3,744	6,841	12,832	16,144	14,705
per boe	15.08	20.96	27.94	13.89	38.54	48.80	53.10	54.29
Funds flow from operations	5,147	7,332	10,532	7,727	5,670	7,476	10,471	10,341
per boe	14.79	22.09	38.14	28.67	31.94	28.43	34.44	38.18
per unit – basic	0.15	0.21	0.30	0.22	0.16	0.22	0.32	0.32
per unit – diluted	0.15	0.21	0.30	0.22	0.15	0.16	0.28	0.25
Earnings (loss)	(23,198)	(51,784)	(6,541)	5,477	(35,192)	8,104	(23,158)	2,218
per unit – basic	(0.67)	(1.48)	(0.19)	0.16	(1.01)	0.24	(0.70)	0.07
per unit - diluted	(0.67)	(1.48)	(0.19)	0.16	(1.13)	0.18	(0.70)	0.02
Cash distributions declared	2,614	3,143	3,130	3,153	7,159	9,036	8,775	8,555
per issued unit	0.07	0.09	0.09	0.09	0.21	0.26	0.26	0.26
Current assets	19,767	21,862	13,382	31,459	33,245	76,566	8,802	9,116
Current liabilities	9,397	8,033	7,754	8,642	10,720	13,587	32,878	33,348
Total assets	208,572	228,959	245,009	265,342	257,172	240,458	320,182	356,332
Total non-current liabilities	92,616	91,316	52,012	60,835	57,547	2,565	80,126	79,684
Unitholders' equity	106,559	129,611	185,243	195,865	188,905	224,306	207,178	243,300
Units issued	34,863	34,893	34,961	35,023	35,017	34,821	33,739	32,836

For the three months ended December 31, 2015, sales volumes increased when compared to the previous quarter due to the full benefits of the acquisition of a private company (refer to the "Business Combination" section of this MD&A) and drilling results exceeding expectations in the Salt Flat field.

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

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. While fourth quarter 2015 funds flow from operations decreased 25% from the third quarter level, a large third quarter impairment charge due to falling commodity prices actually resulted in a lower fourth quarter loss.

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 December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Production						
Oil (bbls/d)	1,859	1,815	2	1,890	2,357	(20)
Natural gas (mcf/d)	292	296	(1)	281	1,226	(77)
Natural gas liquids (bbls/d)	50	65	(23)	55	221	(75)
Oil equivalent sales volumes (boe/d @ 6:1)	**1,958**	1,929	1	**1,992**	2,782	(28)
Activity						
Capital expenditures ($000's)	2,923	105,119	(97)	14,053	(19,465)	(172)
Wells drilled (rig -released)						
Gross	2	2	-	8	7	14
Net	2.0	2.0	-	8.0	6.4	25
Wells brought on-stream						
Gross	-	2		5	7	(29)
Net	-	2.0		5.0	6.4	(22)

$000's	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Sales before royalties	9,267	23,566	(61)	42,260	78,341	(46)
Royalties	(2,646)	(6,423)	(59)	(12,055)	(21,403)	(44)
Operating expenses	(2,882)	(4,148)	(31)	(12,958)	(12,705)	2
Transportation and marketing expenses	(23)	(164)	(86)	(111)	(553)	(80)
Field netback	**3,716**	12,831	(71)	**17,136**	43,680	(61)
($/boe)						
Sales before royalties	51.46	89.61	(43)	58.13	93.49	(38)
Royalties	(14.69)	(24.42)	(40)	(16.58)	(25.54)	(35)
Operating expenses	(16.00)	(15.77)	1	(17.82)	(15.16)	18
Transportation and marketing expenses	(0.13)	(0.62)	(80)	(0.15)	(0.66)	(77)
Field netback	20.64	48.80	(58)	23.58	52.13	(55)

During the fourth quarter of 2015, capital expenditures were $2.0 million in the United States with average working interest sales volumes of 1,958 boe/d.

Revenue for the quarter was received primarily from two customers, Sunoco Logistics Partners L.P. ("Sunoco") and Plains Marketing L.P. ("Plains"), with revenue received amounting to $4.5 million (48%) and $1.2 million (13%) respectively. For the fourth quarter of 2014, $9.6 million (41%) of revenue was received from Sunoco and $1.7 million (7%) from Plains.

Salt Flat Properties, Texas

Eagle drilled three horizontal wells at Salt Flat during 2015, with production from the wells exceeding expectations. Drilling results were aided by seismic data acquired in 2014 which helped target locations. On existing wells, Eagle reduced operating costs on a per boe basis by 10% over the past three years. Salt Flat produces over 100,000 barrels of water per day, which Eagle handled with increased efficiency and cost effectiveness.

Hardeman Properties, Texas and Oklahoma

At Hardeman, Eagle drilled four vertical wells, one of which was a salt water disposal well. The new salt water disposal facility was put into service late in the third quarter and served to reduce operating expenses in the southern part of the Hardeman area. The project required electrification in the southern area which, in addition to powering the salt water disposal facility, will ultimately help improve run time and reduce propane charges in the southern part of the field.

Canada

	Three Months Ended December 31, 2015	**Three Months Ended December 31, 2014**	**%**	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**	**%**
Production						
Oil (bbls/d)	1,487	-	-	1,241	-	-
Natural gas (mcf/d)	1,674	-	-	637	-	-
Natural gas liquids (bbls/d)	59	-	-	19	-	-
Oil equivalent sales volumes (boe/d @ 6:1)	**1,825**	-	-	**1,366**	-	-
Activity						
Capital expenditures ($000's)	3,758	-	-	3,775	-	-

$000's	**Three Months Ended December 31, 2015**	**Three Months Ended December 31, 2014**	**%**	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**	**%**
Sales before royalties	5,955	-	-	21,052	-	-
Royalties	(973)	-	-	(3,136)	-	-
Operating expenses	(2,758)	-	-	(9,150)	-	-
Transportation and marketing expenses	(693)	-	-	(2,243)	-	-
Field netback	**1,531**	-	-	**6,523**	-	-
($/boe)						
Sales before royalties	35.47	-	-	42.23	-	-
Royalties	(5.80)	-	-	(6.29)	-	-
Operating expenses	(16.43)	-	-	(18.35)	-	-
Transportation and marketing expenses	(4.13)	-	-	(4.50)	-	-
Field netback	9.11	-	-	13.09	-	-

During the fourth quarter of 2015, capital expenditures were $3.8 million in Canada with average working interest sales volumes of 1,825 boe per day. Revenue for the fourth quarter was received primarily from Trafigura Canada General Partnership in the amount of $4.1 million. Eagle takes in kind most of its production from the Twining field, and on September 1, 2015, Eagle began to take in kind its non-operated working interest production at Dixonville. The majority of Twining non-operated revenue is also taken in kind.

Dixonville Properties, Alberta

In December 2014, 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. The acquisition was effective January 1, 2015.

Twining Properties, Alberta

On August 20, 2015, the Trust acquired a private company which owned an average 80% working interest in the Twining field in Alberta, located in the Pekisko oil formation in the Western Canadian Sedimentary Basin (refer to the "Business Combination" section of this MD&A). The Twining properties have been integrated into Eagle's operations and Eagle has commenced production improvements with $1.1 million having been spent on well workovers, $350,000 spent on pipelines and facilities, and $200,000 on G&G software, during the fourth quarter.

Corporate

$000's	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	%	Year Ended December 31, 2015	Year Ended December 31, 2014	%
Administrative expenses	(3,512)	(3,788)	(7)	(11,199)	(13,564)	(17)
Risk management gain (loss) - realized	4,017	3,153	27	20,714	149	13,801
Cash settled award payments	(37)	(166)	(77)	(207)	(694)	(70)
Finance expense	(564)	(186)	203	(2,045)	(2,188)	(7)
Income tax recovery	1	(210)	(100)	46	(210)	(122)
Realized foreign exchange gain (loss)	(4)	26	(116)	(230)	(56)	311
Funds flow from operations	**(99)**	(961)	(91)	**7,079**	(16,563)	(143)

For the three and twelve month periods ended December 31, 2015, corporate administrative expenses decreased when compared to the prior year's comparative periods due to one-time transaction costs in 2014 for the internal re-organization as well as one time transaction costs for the sale of the Permian assets in 2014. The reduction in G&A was partially offset by one time transaction costs associated with the acquisition of Twining properties in 2015 (refer to the "Business Combination" section of this MD&A). An active corporate hedging program contributed $20.7 million to funds flow from operations in 2015.

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.

At December 31, 2015, the Trust's ratio of debt to trailing cash flow was approximately 2.1 to 1.0. At December 31, 2015, the authorized borrowing base under the credit facility was $US 80 million against which $CA 65.6 million was drawn by way of bankers' acceptances. In valuing and redetermining the authorized credit facility, the lenders apply their customary internal standards and practices for valuing and redetermining the value of oil and gas properties in connection with reserve based oil and gas loan transactions. In addition, the lenders may also consider the business, financial condition, and debt obligations of the borrower and other factors they customarily deem appropriate, including commodity price assumptions, projections of production, operating expenses, general and administrative expenses, capital costs, working capital requirements, liquidity evaluations, dividend payments, environmental costs, and legal costs. In the event that a borrowing base redetermination results in a reduction of the authorized credit facility below the amount outstanding under the credit facility (such that a "borrowing base deficiency" exists) the credit facility instructs that Eagle must elect to take any one or a combination of the following actions: (1) Repay the borrowing base deficiency within 10 days; (2) pledge additional acceptable collateral such that the borrowing base deficiency is cured within 30 days; (3) deliver an election in writing to the lender to agree to repay borrowing base deficiency in six monthly installments equal to one-sixth of such borrowing base deficiency with the first such installment due thirty (30) days after the date such deficiency notice was received by Eagle. Eagle's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. Eagle manages its capital structure and makes adjustments to it based upon economic conditions and the risk characteristics of the underlying oil and natural gas assets. Eagle sets its distribution levels monthly as well as prepares annual capital expenditure and operating budgets, which are updated as necessary depending on factors such as current and forecast prices, successful capital deployment, authorized borrowing base levels and general industry conditions.

The Trust targets a corporate payout ratio at or below 100% and therefore 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 “2016 Budget and 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 December 31, 2015		**Three Months Ended December 31, 2014**		**Year Ended December 31, 2015**		**Year Ended December 31, 2014**	
$000’s		**/boe**		/boe		**/boe**		/boe
Field netback	5,246	15.08	6,841	38.53	23,659	19.30	50,521	49.75
Cash settled award payments	(37)	(0.11)	(166)	(0.93)	(207)	(0.17)	(694)	(0.68)
Administrative expenses	(3,512)	(10.10)	(3,788)	(21.34)	(11,199)	(9.14)	(13,564)	(13.36)
Realized risk management gain (loss)	4,017	11.54	3,153	17.76	20,714	16.90	149	0.15
Finance expense	(564)	(1.62)	(186)	(1.04)	(2,045)	(1.67)	(2,188)	(2.16)
Income tax recovery	1	-	(210)	(1.18)	46	0.04	(210)	(0.20)
Realized foreign exchange gain (loss)(1)	(4)	(0.01)	26	0.14	(230)	(0.19)	(56)	(0.06)
Funds flow from operations	**5,147**	**14.79**	**5,670**	**31.94**	**30,738**	**25.08**	**33,958**	**33.44**

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

As of December 31, 2015, the Trust had approximately $45.1 million ($US 32.6 million) of unused credit on its $110.7 million ($US 80 million) revolving credit facility, which is held indirectly through its subsidiaries with a syndicate of Canadian chartered banks.

The credit facility has a maturity date of May 27, 2017 and is subject to semi-annual redetermination of the borrowing base by the credit facility lenders no later than May 15 and October 16 of each year. The next redetermination date will be finalized no later than May 15, 2016.

Amounts drawn on the credit facility can be denominated in U.S. or Canadian dollars and may be used for activities in either the U.S. or Canada. The credit facility provides for borrowing by way of LIBOR and base rate loans for amounts drawn in U.S. funds and bankers' acceptances and prime rate loans for amounts drawn in Canadian funds. The margins above base rate, prime rate, LIBOR and bankers' acceptance rate, as applicable, for the credit facility are subject to a pricing grid based on the then applicable ratio of consolidated debt to EBITDAX (the "**Margin Ratio**"). The credit facility documentation also provides for (i) a standby fee for each lender calculated on the lesser of (a) the unused amount of such lender's commitment and (b) the unused amount of such lender's pro rata share of the borrowing base then in effect, at a percentage based on the applicable Margin Ratio and (ii) an issuance fee on the outstanding amount of any letter of credit equal to the margin applicable to LIBOR loans (subject to a reduction in fees for non-financial letters of credit).

Under the credit facility, the Trust is required to satisfy certain customary affirmative and negative covenants (including financial covenants). The credit facility documentation provides for customary negative covenants which, among other things, limit the Trust in making distributions to its unitholders if any default, event of default or borrowing base deficiency has occurred and is continuing or would result from such distribution, or if the cash distributions made for the trailing four quarters exceeds the Available Distributable Cash Flow (as defined by the credit facility agreement and which was $33.9 million at December 31, 2015) for the trailing four quarters. The credit facility documentation also includes other customary restrictive covenants including limitations on indebtedness, liens, contingent obligations, investments, dispositions, mergers, consolidations, liquidations and dissolutions. In addition, the Trust must maintain, as at the end of each fiscal quarter, a minimum current ratio (being the ratio of current assets plus the unused availability under the credit facility less cash subject to restriction and risk management assets and other assets resulting from a mark-to-market valuation is to current liabilities less the current portion of long-term debt and risk management liabilities and other liabilities resulting from a mark-to-market valuation) of not less than 1.00 to 1.00 (6.10 to 1.00 at December 31, 2015), a minimum four quarter trailing interest expense coverage ratio (being the interest expense for the trailing four quarters divided into the four quarter trailing EBITDAX) of not less than 3.00 to 1.00 (12.60 to 1.00 at December 31, 2015). "Interest expense" is defined in the credit facility as the sum of (a) all interest, premium payments, debt discount, fees, charges and related expenses in connection with debt (including capitalized interest and amortization of debt discount) to the extent treated as interest in accordance with IFRS, and (b) the portion of rent expense with respect to such period under capital leases that is treated as interest in accordance with IFRS. The Trust must also maintain, at the end of each fiscal quarter, a maximum debt to four quarter trailing EBITDAX ratio of 3.00 to 1.00 (1.90 to 1.00 at December 31, 2015).

Working Capital

At December 31, 2015, the Trust had cash on hand of $3.1 million, a working capital deficit, excluding non-cash unit-based payments and non-cash risk management asset, of approximately $1.7 million and $65.6 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 and had previously suspended the Premium Distribution™ component of the DRIP. No material Trust capital issuances occurred during 2015. Management may also seek to issue additional units in the future to provide sufficient capital to fund growth, including acquisition opportunities.

For the one year period commencing January 21, 2015 and ending January 20, 2016, the Trust initiated a Normal Course Issuer Bid ("NCIB"). Purchases were 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 purchases of units were at the prevailing market price of the units at the time of purchase and were 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 fourth quarter of 2015, the Trust had purchased for cancellation 30,000 units at a weighted average market price of $1.88 per unit. For the year ended December 31, 2015 the Trust purchased for cancellation 190,300 units at a weighted average market price of $2.36 per unit. The NCIB program expired in January 2016 and has not been renewed.

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 December 31, 2015 and December 31, 2014 is as follows:

	Year Ended December 31, 2015	**Year Ended December 31, 2014**
Number of units issued under the DRIP	36,552	2,868,203
Fair market value of units issued under the DRIP ($000's)	-	2,319
Net proceeds from issuance of Trust capital ($000's)	67	17,421
Average price per unit issued under the DRIP	1.84	6.07
Number of trust units cancelled pursuant to the NCIB	190,300	-
Reduction of Trust capital pursuant to the NCIB ($000's)	(1,833)	-
Average price per unit cancelled pursuant to the NCIB	2.36	-

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 then current and expected commodity prices and lowered its monthly distribution from $0.0875 to $0.03 per unit per month. Beginning with the distribution declared for December, the Trust reduced the monthly distribution from $0.03 per unit per month to $0.015 per unit per month. With ongoing price weakness, the Trust lowered its distribution levels again in February 2016 to $0.01 per month ($0.12 per year, annualized). Cash distributions paid in the fourth quarter (for the September, October and November, 2015 record dates) totaled approximately $2.6 million and $12.0 million for the year ended December 31, 2015.

At December 31, 2015, the Trust had 34,863,364 units issued and outstanding (December 31, 2014 – 35,017,112). As at the date of this MD&A, 42,451,623 common shares of Eagle Energy Inc. are issued and outstanding and 3,017,750 options are outstanding (with a weighted average exercise price of $5.54).

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 December 31, 2015**	**Three Months Ended December 31, 2014**	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
Earnings (loss) for the period	(23,198)	(35,192)	(76,046)	(48,028)
Cash distributions paid	(2,614)	(9,155)	(12,586)	(35,287)
Excess (shortfall) of earnings over cash distributions paid	**(25,812)**	**(44,347)**	**(88,632)**	**(83,315)**
Funds flow from operations[(1)]	5,145	5,670	30,738	33,958
Changes in operating working capital	4,847	870	822	2,579
Abandonment expenditures	-	(212)	-	(212)
Net cash provided by operating activities	9,992	6,328	31,560	36,325
Cash distributions paid	(2,614)	(9,155)	(12,586)	(35,287)
Excess (shortfall) of net cash provided by operating activities over cash distributions paid	**7,378**	**(2,827)**	**18,974**	**1,038**

Note:

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

For the three months and year ended December 31, 2015 and December 31, 2014, cash distributions paid exceeded earnings (loss) for the period due to the non-cash items that are deducted or added in determining earnings for the period. Earnings often do 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 that factor into the calculation of earnings, as well as those that are required to be fair valued at each period end. Examples of non-cash items include depreciation, depletion and amortization, impairment, unit-based compensation and unrealized risk management losses, all of which have no impact on cash available to pay distributions.

For the three months and year ended December 31, 2015, net cash provided by operating activities exceeded cash distributions paid by $7.4 million and $19.0 million respectively due to: (i) decreased general and administrative expenses from the previous year and (ii) reductions in the distribution. Effective with the December 2014 distribution, the Trust took action to protect its balance sheet in light of then current and expected commodity prices by lowering its monthly distribution to $0.03 per unit per month from $0.0875 per unit per month. The distribution was further reduced to $0.015 per unit per month effective with the December 2015 distribution, and to $0.01 per month in February 2016.

Cash distributions paid in the fourth quarter of 2015 were 72% lower than in the fourth quarter of 2014 due to the reduction of the per unit distribution as discussed previously.

Capital Expenditures

Capital expenditures during the quarter and year ended December 31, 2015 and December 31, 2014 were as follows:

$000's	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	Year Ended December 31, 2015	Year Ended December 31, 2014
Exploration and evaluation(1)	930	(16)	930	-
Acquisition - Twining	-	-	27,337	-
Acquisition - Dixonville	-	100,910	-	100,910
Acquisition - Hardeman - 2014	-	-	-	5,409
Disposition - Permian	-	6	-	(150,141)
Intangible drilling and completions	4,344	2,892	11,265	18,194
Seismic	-	458	-	3,742
Well equipment and facilities	2,161	859	5,571	2,360
Other	-	10	62	61
Total Capital Expenditures	**7,435**	105,119	**45,165**	(19,465)

Note:

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

Refer to the "Segmented Operations" section and "Business Combination" section of this MD&A for a discussion of these capital expenditures.

During the year, the Trust spent $5.0 million to drill, complete and equip 3 wells in the Salt Flat CGU. An additional 4 wells, plus one salt water disposal well were drilled, completed and equipped in the Hardeman CGU totaling $7.5 million. The remaining capital was spent to optimize production in the Twining, Salt Flat and Hardeman areas.

Business Combination

Twining property

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

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

Commitments

The Trust has committed to future payments as follows:

$000's	Total	Less than 1 year	1 – 3 years
Operating leases [(1) (2) (3)]	2,362	867	1,495
Total contractual obligations	**2,362**	**867**	**1,495**

Notes:

(1) On January 1, 2013, the Trust entered into a lease for office space in Calgary which has an approximate 61 month term from January 8, 2013 to February 7, 2018. Future minimum lease payments during the term of the lease are approximately $2.4 million and include a leasehold improvements allowance up to $0.3 million, with 25 months and approximately $1.0 million remaining at December 31, 2015.

(2) On August 20, 2015, concurrent with the closing of the acquisition of a private company, the Trust assumed an obligation for the private company's office lease. The term of the lease is from March 1, 2011 to February 28, 2017. Future minimum lease payments during the term of the lease are approximately $1.4 million, with 14 months and approximately $0.3 million remaining at December 31, 2015.

(3) The Trust entered into a lease in Houston on April 1, 2011, which originally had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease was extended for an additional 63 month period from October 1, 2013 to December 31, 2017 and the premise space was expanded to incorporate additional square footage. Future minimum lease payments during the term of the lease include a leasehold improvement allowance of $US 0.1 million and approximately $US 0.9 million, with 24 months and approximately $US 0.6 million remaining at December 31, 2015. In $CA the remaining future minimum lease payments approximate $0.8 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.38.

Legal Proceedings

The Trust is involved in various litigation and claims in the normal course of the Trust's operations. Although the outcome of these claims cannot be predicted with certainty, the Trust does not expect these matters to have a material adverse effect on Eagle's financial position, cash flows or results of operations. If an unfavorable outcome were to occur, there exists the possibility of a material adverse impact on the Trust's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Trust determines that the loss is probable and the amount can be reasonably estimated. The Trust believes it has made adequate provision for such legal claims.

Transactions with Related Parties

Key Management Personnel

Key management personnel includes the Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, the Vice-Presidents, General Counsel/Corporate Secretary and the outside Directors.

Intercompany Transactions

There are certain intercompany transactions among the subsidiaries comprising the consolidated financial statements of the Trust. These transactions have been eliminated upon consolidation.

Critical Accounting Estimates and Judgments

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

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

Estimation of Oil and Gas Reserves

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

Capitalized Exploration and Evaluation Expenditures

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

Business Combinations

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

Decommissioning Provision

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

Impairment of Property, Plant and Equipment

The recoverable amounts of CGUs and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to dispose. These calculations require the use of estimates and assumptions. It is reasonably possible that the commodity price assumption may change, which may impact the estimated life of the asset and may require a material adjustment to the carrying value of assets. The Trust monitors recent transaction within the industry, long-term views of commodity prices, externally evaluated reserves volumes and discount rates specific to the CGU.

Income Taxes

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

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

Derivative Financial Instruments

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

Classification of Trust Units as Equity

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

Contingencies

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

Unit-based Compensation

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

Accounting Standards and Interpretations Adopted

The Trust adopted the following new and revised standards, along with any consequential amendments, effective January 1, 2014. These changes were made in accordance with the applicable transitional provisions.

- On January 1, 2014, the Trust adopted International Financial Reporting Interpretations Committee ("IFRIC") Interpretation 21-Levies, which addresses payments to government bodies. There was no material impact to the Trust as a result of adopting the new standard.

- IAS 36 - Impairment of Assets - the IASB issued amendments to IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGU's is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. This amendment is effective for annual periods beginning on or after January 1, 2014.

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

Accounting Standards and Interpretations 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.
- In January 2016, the IASB issued IFRS 16 *Leases* which replaces the existing leasing standard (IAS 17 *Leases*) and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the term is twelve months or less and for leases of low value items. The accounting treatment for lessors remains the same, which provides the choice of classifying a lease as either a finance or operating lease. IFRS 16 is effective January 1, 2019, with earlier application permitted. The adoption of this standard could impact the Trust in the event that it has, or enters into leases which would currently be classified as operating leases. The Trust is currently assessing the impact of this standard.

Additional adjustments to the Trust's accounting policies may be required upon completion of a separate IASB framework for extractive industries.

Risk Management

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

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

Credit risk is the risk of financial loss to the Trust if a 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 marketers and joint venture partners. The Trust limits its exposure, in this regard, by investing only in liquid securities, by taking its products in kind from joint venture partners when practical, by cash-calling joint venture partners when undertaking their share of significant capital expenditures and by transacting with marketing counterparties with a strong credit rating or who have provided adequate security.

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

Receivables from the Trust's product marketers are normally collected in the month following production. The Trust's policy to mitigate credit risk associated with these balances is to establish marketing relationships with reputable purchasers with good credit. The Trust historically has not experienced collection issues with its marketers. If required, the Trust would obtain collateral from its marketers but has not typically needed to do so.

Joint venture receivables are with customers in the oil and gas industry and are subject to normal industry credit risks. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. In certain circumstances, the Trust may request an operating advance or cash call a partner in advance of capital expenditures being incurred. With respect to receivables related to non-operated properties the Trust endeavours to take its revenue in kind, and, provisions in the joint operating agreement allow the Trust to assume operatorship in certain circumstances.

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

At December 31, 2015, the Trust had a working capital surplus, excluding the risk management asset, of approximately $1.4 million and a $110.7 million ($US 80 million) Canadian dollar equivalent authorized credit facility. At December 31, 2015, $45.1 million ($US 32.6 million) credit was available under the facility. Refer to "Liquidity and Capital Resources". To better manage its liquidity risk, the Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures ("AFEs") on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil and natural gas revenue each month.

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.

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 many factors including world economic events that dictate the levels of supply and demand and the relationship between the Canadian and United States dollar. 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. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. As at the date of this MD&A, the Trust has entered into contracts to mitigate the effect of commodity price fluctuations. Refer to the "Realized and Unrealized Risk Management Gain/Loss" section of this MD&A.

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. The Trust's operating cash flows are generated in US dollars and distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust's treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil are determined in global markets and denominated in US dollars. Generally, an increase in the value of the $CA as compared to the $US will reduce the prices received by the Trust for its petroleum and natural gas sales, but will also reduce the operating expenses associated with those sales as well as reduce the price paid by the subsidiary of the Trust for future asset acquisitions. During 2015, the Trust did not enter into any foreign exchange contracts. Refer to the “Realized and Unrealized Risk Management Gain/Loss” section of this MD&A.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. As at December 31, 2015, $65.6 million had been drawn against the $110.7 million credit facility (December 31, 2014 - $47.2 million drawn against the total credit facility of $81.2 million). The Trust did not hedge against any interest rate exposure.

Non-IFRS Financial Measures

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

“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 dividends, 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 for a reconciliation of funds flow from operations to earnings (loss).

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

“**Basic payout ratio**” is calculated by dividing shareholder dividends by funds flow from operations.

“Corporate payout ratio” is calculated by dividing capital expenditures (excluding acquisition capital) plus shareholder dividends by funds flow from operations.

“EBITDAX”, as defined in the Trust’s credit facility, means:

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

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

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

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

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

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

In addition, EBITDAX is calculated after giving effect on a pro-forma basis to any permitted acquisition or asset disposition as if such acquisition or disposition occurred at the beginning of such period.

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 December 31, 2015	Three Months Ended December 31, 2014	Year ended December 31, 2015	Year ended December 31, 2014
Earnings (loss)	(23,198)	(35,192)	(76,046)	(48,028)
Add back (deduct) items not involving cash				
Unit-based compensation – non-cash portion	(561)	(2,880)	(1,089)	(8,294)
Unrealized risk management loss (gain)	(397)	(13,190)	7,962	(15,718)
Depreciation, depletion and amortization	6,021	7,236	26,396	35,846
Impairment	25,980	49,604	87,255	69,685
Finance expense - non cash portion	300	92	928	467
Foreign exchange loss (gain) on intercompany loan	(2,992)	-	(14,668)	-
Funds flow from operations	**5,151**	5,670	**30,738**	33,958
Add back (deduct items not directly related to field operations				
Finance expense (cash portion)	564	186	2,045	2,188
Realized foreign exchange loss (gain)	4	(26)	230	56
Risk management (gain) loss-realized	(4,017)	(3,153)	(20,714)	(149)
Administrative expenses	3,514	3,788	11,199	13,564
Income tax recovery	(1)	210	(46)	210
Cash settled award payments	37	166	207	694
Field netback	**5,251**	6,841	**23,659**	50,521

Conclusions regarding the design and effectiveness of disclosure controls and procedures

Disclosure controls and procedures are controls and procedures designed to provide reasonable assurance that information required to be disclosed in reports filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis and is accumulated and communicated to the Trust’s management, including the Chief Executive Officer and the Chief Financial Officer as appropriate, to allow timely decisions regarding required disclosure. As at December 31, 2015, the Chief Executive Officer and the Chief Financial Officer evaluated the design and operation of the Trust’s disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the Trust’s disclosure controls and procedures were effective as at December 31, 2015.

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

Internal controls are processes designed and implemented by Management to provide reasonable assurance regarding the reliability of the Trust’s financial reporting and the preparation of financial statements and other financial information for external purposes in accordance with IFRS. Based on an evaluation of the Trust’s internal controls over financial reporting as at December 31, 2014, the Chief Executive Officer and the Chief Financial Officer concluded that the Trust’s internal controls over financial reporting were effective.

No change in internal controls over financial reporting during the period October 1, 2015 to December 31, 2015

During the period beginning on October 1, 2015 and ended on December 31, 2015, there was no change in the Trust’s internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust’s internal controls over financial reporting. It should be noted, that the Trust’s control system, no matter how well designed, can provide only reasonable, but not absolute, assurance of detecting, preventing and deterring errors or fraud.

Note about Forward-Looking Statements

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

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

- Eagle's 2016 capital budget;
- Eagle's estimated volumes and values of reserves;
- Eagle's expectations regarding its 2016 full year average working interest production, operating costs and field netbacks (excluding hedges);
- Eagle's expectations regarding its 2016 funds flow from operations, basic and corporate payout ratios and debt to trailing cash flow, and sensitivities of some of these metrics to changes in production rates and commodity prices;
- future development costs associated with reserves;
- projected percentage weighting of crude oil, natural gas liquids and natural gas production levels;
- Eagle's expectations regarding dividend levels; and
- Management's view that Eagle's expected funds flow from operations and undrawn credit facility will be sufficient to fund its current and expected financial obligations.

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

- future oil, natural gas liquid and natural gas prices and weighting;
- future currency exchange rates;
- the regulatory framework governing taxes in the US and Canada;
- future recoverability of reserves and the accuracy of the estimates of Eagle's reserves volumes and values;
- future dividend levels;
- future capital expenditures and the ability of Eagle to obtain financing on acceptable terms for its capital projects and future acquisitions;
- Eagle's 2016 capital budget, which is subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions and regulations;
- not including capital required to pursue future acquisitions in the forecasted capital expenditures;
- the ability of Eagle to compete for new acquisitions;
- estimates of anticipated future production, which is based on the proposed 2016 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.

Eagle'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;
- the regulatory framework governing taxes in the U.S. and Canada; and
- new regulations and legislation that apply to Eagle and the operations of its subsidiaries.

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

As a result of these risks, actual performance and financial results in 2016 may differ materially from any projections of future performance or results expressed or implied by these forward-looking statements. Eagle's production rates, operating costs, field netbacks, drilling program, 2016 capital budget, funds flow from operations, reserves and dividends 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 Eagle'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 Eagle and its shareholders. These statements speak only as of the date of this MD&A and may not be appropriate for other purposes. Eagle does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise.

Note Regarding Barrel of Oil Equivalency

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

Eagle Energy Trust

(the predecessor reporting issuer to Eagle Energy Inc.)

Consolidated Financial Statements
(in Canadian dollars)

For the Years ended December 31, 2015 and December 31, 2014

Management's Report to the Unitholders of Eagle Energy Trust

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

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

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

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

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

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

MARCH 17, 2016

(signed) Kelly A. Tomyn
Kelly A. Tomyn
Chief Financial Officer

MARCH 17, 2016

March 17, 2016

Independent Auditor's Report

To the Unitholders of
Eagle Energy Trust

We have audited the accompanying consolidated financial statements of Eagle Energy Trust and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014 and the consolidated statements of earnings (loss) and comprehensive income (loss), statements of changes in unitholders' equity and statements of cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

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

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

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Eagle Energy Trust and its subsidiaries as at December 31, 2015 and December 31, 2014 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Eagle Energy Trust

Consolidated Balance Sheets

(Thousands of Canadian dollars)

	Note	**December 31, 2015**	December 31, 2014
ASSETS			
Current assets			
Cash		3,089	11,127
Trade and other receivables		5,207	6,669
Prepaid expenses		2,309	530
Risk management asset	4	9,162	14,919
		19,767	**33,245**
Non-current assets			
Exploration and evaluation asset	15	1,033	-
Oil and gas properties	16	186,859	222,939
Property, plant and equipment		168	219
Other intangible assets		745	769
		188,805	**223,927**
Total Assets		**208,572**	**257,172**
LIABILITIES			
Current liabilities			
Trade and other payables		8,647	8,316
Distributions payable		523	1,068
Unit-based payments	8	227	1,336
		9,397	**10,720**
Non-current liabilities			
Debt	17	65,618	47,200
Deferred income tax	11	-	-
Decommissioning liability	18	26,998	10,347
		92,616	**57,547**
Total Liabilities		**102,013**	**68,267**
UNITHOLDERS' EQUITY			
Trust capital	19	315,379	317,150
Currency reserves	9	35,615	29,494
Accumulated loss		(116,080)	(41,424)
Accumulated cash distributions	20	(128,355)	(116,315)
Total Unitholders' Equity		**106,559**	**188,905**
Total Liabilities and Unitholders' Equity		**208,572**	**257,172**

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

See note 22 "Commitments" and note 23 "Subsequent events".

Eagle Energy Trust

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

(Thousands of Canadian dollars, except per unit amounts)

	Note	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Revenue		63,312	92,413
Royalties		(15,191)	(25,238)
		48,121	**67,175**
Operating expenses		22,108	16,062
Transportation and marketing expenses		2,354	592
Administrative expenses		11,199	13,564
Impairment	12	87,255	69,531
Depreciation, depletion and amortization	12	26,396	35,846
Exploration and evaluation	15	-	154
Operating loss		**(101,191)**	**(68,574)**
Unit based compensation expense (recovery)	8	(882)	(7,600)
Finance expense	10	2,973	2,655
Risk management loss (gain)	4	(12,752)	(15,867)
Foreign exchange loss (gain) net	9	(14,438)	56
Earnings (loss) before taxes		**(76,092)**	**(47,818)**
Income tax expense (recovery)	11	(46)	210
Earnings (loss)		**(76,046)**	**(48,028)**
Foreign currency translation gain (loss)	9	6,121	18,394
Comprehensive earnings (loss)		**(69,925)**	**(29,634)**
Earning (loss) per unit			
Basic	14	**(2.18)**	**(1.43)**
Diluted	14	**(2.18)**	**(1.55)**

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

Eagle Energy Trust

Consolidated Statements of Changes in Unitholders' Equity

For the years ended December 31, 2015 and December 31, 2014

(Thousands of Canadian dollars)

	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		-	-	-	(48,028)	-	(48,028)	(48,028)
Foreign currency translation gain	9	-	-	18,394	-	-	-	18,394
Total comprehensive earnings (loss)		-	-	18,394	(48,028)	-	(48,028)	(29,634)
Issuance of trust capital	19	2,868	19,740	-	-	-	-	19,740
Trust unit issuance costs	19	-	(37)	-	-	-	-	(37)
Unitholder distributions	20	-	-	-	-	(35,861)	(35,861)	(35,861)
		2,868	19,703	-	-	(35,861)	(35,861)	(16,158)
Balance at December 31, 2014		**35,017**	**317,150**	**29,494**	**(41,424)**	**(116,315)**	**(157,739)**	**188,905**
Loss		-	-	-	(76,046)	-	(76,046)	(76,046)
Foreign currency translation gain	9	-	-	6,121	-	-	-	6,121
Total comprehensive earnings (loss)		-	-	6,121	(76,046)	-	(76,046)	(69,925)
Issuance of trust capital	19	36	67	-	-	-	-	67
Cancellation of trust capital pursuant to NCIB	19	(190)	(1,833)	-	1,390	-	1,390	(443)
Trust unit issuance costs	19	-	(5)	-	-	-	-	(5)
Unitholder distributions	20	-	-	-	-	(12,040)	(12,040)	(12,040)
		(154)	(1,771)	-	1,390	(12,040)	(10,650)	(12,421)
Balance at December 31, 2015		**34,863**	**315,379**	**35,615**	**(116,080)**	**(128,355)**	**(244,435)**	**106,559**

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

Eagle Energy Trust

Consolidated Cash Flow Statements

(Thousands of Canadian dollars)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Cash flows from operating activities		
Earnings (Loss)	(76,046)	(48,028)
Adjustments for non-cash items:		
Impairment	87,255	69,531
Depreciation, depletion and amortization	26,396	35,846
Exploration and evaluation	-	154
Unit-based compensation – non-cash portion	(1,089)	(8,294)
Unrealized risk management loss (gain)	7,962	(15,718)
Foreign exchange loss (gain) on intercompany loan	(14,668)	-
Finance expense	928	467
	30,738	**33,958**
Changes in working capital:		
Trade and other receivables	2,431	1,757
Prepaid expenses	(969)	140
Trade and other payables	(640)	685
	822	2,579
Abandonment expenditures	-	(212)
Net cash generated by operating activities	**31,560**	**36,325**
Cash flows from investing activities		
Exploration and evaluation assets	(930)	-
Oil and gas properties	(15,762)	(24,297)
Property, plant and equipment	(62)	(61)
Acquisition of oil and gas assets	(4,531)	(106,319)
Disposition of oil and gas assets	-	150,141
Change in non-cash working capital	(173)	1,174
Net cash generated by (used in) investing activities	**(21,458)**	**20,638**
Cash flows from financing activities		
Debt	18,418	(30,921)
Debt – acquisition of oil and gas assets	(22,806)	
Proceeds from issuance of units	67	17,421
Purchase of trust units for cancellation	(463)	-
Trust unit issue costs	(5)	(37)
Cash distributions to unitholders	(12,586)	(35,287)
Deferred financing charges	(432)	(513)
Change in non-cash working capital	(727)	-
Net cash generated by (used in) financing activities	**(18,534)**	**(49,337)**
Net increase (decrease) in cash and cash equivalents	**(8,432)**	**7,626**
Effects of exchange rates on cash and cash equivalents	394	2,066
Cash at beginning of the period	11,127	1,435
Cash at end of the period	**3,089**	**11,127**

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

Eagle Energy Trust

Notes to Consolidated Financial Statements

For the years ended December 31, 2015 and December 31, 2014
(in Canadian dollars)

1. Reporting Entity / Structure of the Trust

Refer to note 23 “Subsequent Events” where the January 27, 2016 acquisition and conversion of Eagle Energy Trust to a corporate structure is described. The following is a description of Eagle Energy Trust and its subsidiaries as at December 31, 2015.

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

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

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

The strategy of the Trust is to invest in operating subsidiaries that will acquire on-shore petroleum reserves and production in certain regions of Canada and the United States. The Trust’s subsidiaries do not intend to engage substantively in exploration activities.

The Trust intends to make monthly distributions of a portion of its available cash to unitholders and use the remainder of its available cash to reinvest in its subsidiaries to fund growth through additional acquisitions and capital expenditures. Cash flow is provided to the Trust from properties owned and operated by the indirectly owned subsidiaries of the Trust, Eagle Hydrocarbons Inc., Eagle Energy Canada Inc. and Eagle-Coda Petroleum Inc.

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

2.1. Basis of Preparation

Functional Currency and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the Trust’s functional currency. The foreign exchange rate used to convert the US subsidiary to Canadian dollars at December 31, 2015 was $US 1.00 equal to $CA 1.38 (December 31, 2014 - $US 1.00 equal to $CA 1.16), and the average foreign exchange rate for the year ended December 31, 2015 was $US 1.00 equal to $CA 1.28 (for the year ended December 31, 2014 - $US 1.00 equal to $CA 1.10).

Basis of Accounting

The consolidated financial statements were authorized for issue in accordance with a resolution of the Board of Directors made on March 17, 2016.

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

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

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

Basis of Consolidation

The consolidated financial statements incorporate the financial statements of the Trust and its subsidiaries up to the balance sheet date. Subsidiaries are all entities over which the Trust has the power to govern the financial and operating policies. Subsidiaries are fully consolidated from the date on which control is transferred and continue to be consolidated until the date that control ceases. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

A list of the subsidiaries has been included in note 5 “Subsidiaries and consolidated entities”.

2.2. Recently Announced Accounting Pronouncements

The standards and interpretations that are issued, but not effective up to the date of issuance of the Trust's consolidated financial statements, and that may have an impact on the disclosures and financial position of the Trust, are disclosed below. The Trust intends to adopt these standards and interpretations, if applicable, when they become effective.

Accounting for Acquisitions of Interests in Joint Operations

In May 2014, the IASB issued amendments to IFRS 11 *Joint Arrangements* to clarify that the acquirer of an interest in a joint operation in which the activity constitutes a business is required to apply all of the principles of business combinations accounting in IFRS 3 *Business Combinations.* Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the Trust in the event it increases or decreases its ownership share in an existing joint operation or invests in a new joint operation.

Sale or Contribution of Assets between an Investor and its Associate or Joint Venture

In September 2014, the IASB issued amendments to address an inconsistency between the requirements in IFRS 10 *Consolidated Financial Statements* and those in International Accounting Standard (IAS) 28 *Investments in Associates and Joint Ventures* regarding the sale or contribution of assets between an investor and its associate or joint venture. The amendment clarified that a full gain or loss is recognized when a transaction involves a business. A partial gain or loss is recognized when a transaction involves assets that do not constitute a business. Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the Trust in the event that it has transactions with Associates or Joint Ventures.

Disclosure Initiative

In December, 2014, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to clarify existing requirements related to materiality, order of notes, subtotals, accounting policies and disaggregation. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the Trust's disclosure.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers.* It replaces existing revenue recognition guidance and provides a single, principles-based five-step model to be applied to all contracts with customers. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The Trust is currently assessing the impact of this standard.

Financial Instruments: Recognition and Measurement

In July 2014, IFRS 9 *Financial Instruments* was issued as a complete standard, including the requirements previously issued related to classification and measurement of financial assets and liabilities, and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or about January 1, 2018, with earlier application permitted. The Trust is current assessing the impact of this standard.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces the existing leasing standard (IAS 17 *Leases*) and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the term is twelve months or less and for leases of low value items. The accounting treatment for lessors remains the same, which provides the choice of classifying a lease as either a finance or operating lease. IFRS 16 is effective January 1, 2019, with earlier application permitted. The adoption of this standard could impact the Trust in the event that it has, or enters into leases which would currently be classified as operating leases. The Trust is currently assessing the impact of this standard.

2.3. Significant Accounting Policies

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

Business Combinations

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

Joint Arrangements

Many of the Trust’s oil and natural gas activities involve interests in joint arrangements. Joint arrangements are categorized as either joint operations or joint ventures, depending on the rights and obligations of the parties in the arrangement. Joint operations arise when the Trust has rights to the assets and obligations for the liabilities of the arrangement. The consolidated financial statements include the Trust’s share of assets, liabilities, revenues and related costs of the joint operation. Joint ventures arise when the Trust has rights to net assets of the arrangement. Joint ventures are accounted for under the equity method.

Foreign Currency Translation

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

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

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

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

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

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

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

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

Where a subsidiary that is a foreign operation repays or partially repays an equity-like loan or returns or partially returns trust unit capital but there is no change in the parent's proportionate percentage of ownership interest, the Trust's chosen accounting policy is that "ownership interest" refers only to the proportionate interest that the parent continues to own. Since the parent would continue to own the same percentage of the subsidiary and continue to control the foreign operation, no change in the parent's proportionate percentage of ownership interest would result and no disposal or partial disposal of ownership interest would occur that would have to be reclassified from the Cumulative Translation Adjustment (CTA) account into income. The loan is denominated in Canadian dollars and held by the Trust's US subsidiary. Interest is paid monthly.

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

Financial Instruments

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

A. Non-Derivative Financial Instruments

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

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

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

(a) Financial Assets

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

(i) Loans and Receivables

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

Cash is comprised of cash on hand.

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

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

(ii) Impairment of Financial Assets

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

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

(b) Financial Liabilities and Equity

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

(i) Trade payables and distributions payable

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

(ii) Borrowings

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

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

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

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

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

(iii) Equity Instruments

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

(iv) Compound Instruments

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

B. Derivative Financial Instruments

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

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

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

(a) Fair Value Hierarchy

To estimate fair value of derivatives, the Trust uses quoted market prices when available, or third-party models and valuation methodologies that utilize observable market data. In addition to market information, the Trust incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The Trust characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities. *Active markets* are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace.

Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. In forming estimates, the Trust utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement.

Non-Current Assets held for Sale

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

Exploration and Evaluation Expenditures

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

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

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

Oil and Gas Properties

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

Depreciation, Depletion and Amortization

Exploration and evaluation assets are not subject to depreciation, depletion and amortization. Once transferred to oil and gas properties and commercial production commences, these costs are depleted on a unit-of-production basis over proved plus probable developed reserves.

Costs are amortized only once commercial reserves associated with a development project can be determined and commercial production has commenced.

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

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

Impairment - Exploration and Evaluation Expenditures

Exploration and evaluation assets are assessed for impairment if:

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

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

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

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

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

Impairment – Oil and Gas Properties

Oil and gas properties (which are further classified as developed oil and gas assets and production facilities and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Oil and gas properties are grouped into CGUs for impairment testing. At this time, the Trust has grouped its oil and gas properties into four CGUs: the Salt Flat properties, the Hardeman properties, the Dixonville properties and the Twining properties. An impairment loss is recognized for the amount by which the asset's or CGU's carrying amount exceeds its recoverable amount. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to dispose. In determining fair value less costs to dispose, the Trust will consider recent transactions within the industry, long-term views of commodity prices, externally evaluated reserves volumes and discount rates specific to the CGU.

Decommissioning Provision

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

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

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

Other Assets

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

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

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

Improvements to leasehold property	2-10 years (or over the remaining life of the lease if shorter)
Office furniture, fixtures and equipment	3 years
Computer equipment	2 years
Vehicles	5 years

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

Revenue Recognition

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

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

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

Costs associated with the sale of crude oil, natural gas liquids and natural gas such as taxes and field operating expenses are reflected individually.

Unit-Based Compensation

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

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

Finance Income and Expense

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

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

Unitholder Distributions

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

Taxation

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

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

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

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

The Trust is a “SIFT trust” within the meaning of the *Income Tax Act* (Canada) (the "Tax Act") and as a SIFT trust, the Trust is taxable only on income that: (i) constitutes "non-portfolio earnings" (within the meaning of the Tax Act); or (ii) is not distributed or distributable to the Unitholders. The Trust's indirect Canadian investments on December 18, 2014 and August 20, 2015 are not anticipated to give rise to any "non-portfolio earnings" since the only income the Trust is expected to receive from the Canadian operations will be in the form of returns of capital or taxable dividends from its Canadian subsidiary. As taxable dividends are paid out of the subsidiary's after-tax corporate income, SIFT tax is not anticipated to apply to the Trust or its affiliates (consistent with the policy behind the SIFT tax regime). The Trust has distributed all of its taxable income to the Unitholders. As a consequence, it is not anticipated that the Trust will be subject to any Canadian federal income tax.

As the Trust holds “taxable Canadian property” (as defined in the Tax Act) it is subject to certain limits on non-resident ownership, and the trust indenture provides certain powers to the trustee in relation thereto.

The Trust's indirect Canadian subsidiaries are in the business of acquiring, developing and producing oil and natural gas reserves in Canada. Canadian corporate subsidiaries of the Trust that own Canadian oil and gas assets will be taxed in the same manner as other Canadian oil and gas corporations, including being subject to Canadian federal income tax to the extent that taxable income cannot be reduced by claiming permitted deductions (such as wages and other employment expenses, interest payments, various Canadian resource expenditures and certain capital expenditures). The Trust’s Canadian corporate subsidiaries, like many Canadian petroleum exploration and production companies, maximize available deductions in order to minimize corporate tax. After-tax cash flow of any Canadian subsidiaries are distributed to the Trust by way of returns of capital and taxable dividends. As such, any income tax borne by a corporate subsidiary reduces the amount available for distribution to Unitholders.

The Trust’s indirect US subsidiary is in the business of acquiring, developing and producing oil and natural gas reserves in the United States. As a general rule, a foreign corporation engaged in a United States trade or business is subject to U.S. federal income tax on income that is effectively connected (effectively connected income, or “ECI”) with the United States trade or business and, if an income tax treaty with the United States applies, is attributable to a permanent establishment maintained by the foreign corporation in the United States. ECI is subject to United States federal income tax on a net basis at the regular United States federal graduated rates of tax that apply to United States persons. A foreign corporation’s taxable income is computed by claiming deductions that are attributable to the effectively connected gross income on a timely filed return. A foreign corporation that derives ECI is generally required to make quarterly payments of estimated United States tax, and is required to file a United States federal income tax return. Eagle Hydrocarbons Inc. deducts interest paid on certain intercompany notes and other deductible expenses, including intangible drilling and developments costs and depletion in calculating its US taxable income.

Trust Unit Calculations

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

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

Earnings (Loss) Per Unit

Basic earnings (loss) per unit is calculated by dividing the net earnings for the period by the weighted average number of trust units outstanding during the period.

Diluted earnings per unit is calculated by adjusting the weighted average number of trust units outstanding for dilutive units related to the Trust's unit-based compensation plan. The number of units included is computed using the treasury stock method. As the awards can be exchanged for units of the Trust, they are considered potentially dilutive and are included in the calculation of the Trust's diluted net earnings per share if they have a dilutive impact in the period.

Business Combinations

For each business combination undertaken, the Trust identifies which of the combining entities should be identified as the acquirer. In certain cases, the legal acquirer will be identified as the acquirer for accounting purposes. In determining the acquirer for accounting purposes, we consider factors such as the relative voting rights in the combined entity after the business combination, the composition of the governing body of the combined entity, the composition of the senior management of the combined entity along with other relevant factors.

SIC 25 Policy

When the Trust converts to a corporate structure, the Trust will re-measure its deferred tax assets and liabilities in accordance with SIC-25: Changes in Tax Structure of an Entity using the tax rates applicable to a corporate structure which do not vary depending on whether income is distributed or not.

3. Critical Accounting Estimates and Judgments

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

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

Estimation of Oil and Natural Gas Reserves

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

Capitalized Exploration and Evaluation Expenditures

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

Business Combinations

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

Decommissioning Provision

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

Impairment of Oil and Gas Assets

The recoverable amounts of CGU's and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to dispose. These calculations require the use of estimates and assumptions. It is reasonably possible that the commodity price assumption may change, which may impact the estimated life of the asset and may require a material adjustment to the carrying value of assets. The Trust monitors recent transactions within the industry, long-term views of commodity prices, externally evaluated reserves volumes and discount rates specific to the CGU.

Income Taxes

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

Derivative Financial Instruments

As described in note 4 "Financial risk management", derivative financial instruments are used by the Trust to manage its exposure to market risks relating to commodity prices. The Trust's policy is not to use derivative financial instruments for speculative purposes. Derivative financial instruments that do not qualify, or are not designated, as hedges for accounting are recorded at fair value. Instruments are recorded in the balance sheet as either an asset or a liability with changes in fair value recognized in the income statement. The estimate of fair value of all derivative instruments is based on quoted market prices, or in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Classification of Trust Units as Equity

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

Contingencies

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

Unit Based Compensation

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

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

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

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

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

Credit Risk

Credit risk is the risk of financial loss to the Trust if a customer, joint venture partner or counterparty to a financial instrument fails to meet its contractual obligations. It arises principally from the Trust's receivables from its product marketers and joint venture partners. The Trust limits its exposure in this regard, by investing only in liquid securities, by taking its products in kind from joint venture partners when practical, by cash-calling joint venture partners when undertaking their share of significant capital expenditures and by transacting with marketing counterparties with a strong credit rating or who have provided adequate security.

At December 31, 2015, the maximum exposure to credit risk was as follows:

$000's	**December 31, 2015**	December 31, 2014
Cash	3,089	11,127
Trade and other receivables	5,207	6,669
Risk management asset	9,162	14,919
	17,458	32,715

Cash

The Trust holds cash in bank accounts or limits its exposure to credit risk by investing only in liquid securities and only with counterparties with a strong credit rating.

Risk Management Asset

The Trust enters into certain risk management contracts periodically to economically hedge a portion of its oil and natural gas sales and manage its foreign exchange exposure. The counterparties to these instruments are highly rated corporate, investment banking, and capital markets groups. Given this approach, Management does not expect any counterparty to fail to meet its obligations as at December 31, 2015. See "Market Risk" and "Commodity Price Risk" for further discussion regarding these risk management contracts.

Trade and other Receivables

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

Receivables from the Trust’s product marketers are normally collected in the month following production. The Trust’s policy to mitigate credit risk associated with these balances is to establish marketing relationships with reputable purchasers with good credit. The Trust historically has not experienced collection issues with its marketers. If required, the Trust would obtain collateral from its marketers but has not typically needed to do so.

Joint venture receivables are with customers in the oil and gas industry and are subject to normal industry credit risks. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. In certain circumstances, the Trust may request an operating advance or cash call a partner in advance of capital expenditures being incurred. With respect to receivables related to non-operated properties, the Trust endeavours to take its revenue in kind and provisions in the joint operating agreement allow the Trust to assume operatorship in certain circumstances.

The Trust has not had any losses from non-performance by these customers. As such, no provision for doubtful accounts has been recorded at December 31, 2015 and December 31, 2014.

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

$000’s	**December 31, 2015**	December 31, 2014
Oil and natural gas marketing companies	4,053	4,978
Receivable from joint venture working interest owners	1,078	1,388
Other	76	303
	5,207	6,669

The Trust’s most significant customers are two US oil and natural gas marketers, one Canadian oil marketer and two financial institutions and account for 78% or $4.0 million of trade and other receivables at December 31, 2015 and 75% or $5.0 million at December 31, 2014. Additionally, 21% of trade and other receivables or $1.1 million represents amounts due from joint venture working interest partners at December 31, 2015 and 21% or $1.4 million at December 31, 2014. As of December 31, 2015 and December 31, 2014, substantially all of the receivables were considered current (less than 90 days old) and none were considered impaired.

Liquidity Risk

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

At December 31, 2015, the Trust had a working capital surplus, excluding the risk management asset and unit-based compensation, of approximately $0.8 million and a $110.7 million ($US 80 million) Canadian dollar equivalent authorized credit facility. At December 31, 2015, $45.1 million ($US 32.6 million) credit was available under the facility. See note 17 “Debt”. To better manage its liquidity risk, the Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures (“AFEs”) on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil and natural gas revenue each month.

The semi-annual redetermination review of the credit facility was held on October 7, 2015 and Eagle’s credit facility was set at $US 80 million. There were no changes to the pricing, covenants or conditions of the credit facility. The next semi-annual redetermination review of the credit facility will be finalized no later than May 15, 2016. In valuing and redetermining the authorized credit facility, the lenders apply their customary internal standards and practices for valuing and redetermining the value of oil and gas properties in connection with reserve based oil and gas loan transactions. In addition, the lenders may also consider the business, financial condition, and debt obligations of the borrower and other factors they customarily deem appropriate, including commodity price assumptions, projections of production, operating expenses, general and administrative expenses, capital costs, working capital requirements, liquidity evaluations, dividend payments, environmental costs, and legal costs. In the event that a borrowing base redetermination results in a reduction of the authorized credit facility below the amount outstanding under the credit facility (such that a “borrowing base deficiency” exists) the credit facility instructs that Eagle must elect to take any one or a combination of the following actions: (1) Repay the borrowing base deficiency within 10 days; (2) pledge additional acceptable collateral such that the borrowing base deficiency is cured within 30 days; (3) deliver an election in writing to the lender to agree to repay borrowing base deficiency in six monthly installments equal to one-sixth of such borrowing base deficiency with the first such installment due thirty (30) days after the date such deficiency notice was received by Eagle.

The following are the contractual undiscounted maturities of financial liabilities, including estimated interest payments, as applicable, at December 31, 2015:

$000's	Carrying amount	Contractual cash flows	Less than one year	One - two years	Two - five years	More than five years
Trade and other payables	8,647	8,647	8,647	-	-	-
Distributions payable	523	523	523	-	-	-
Debt	65,618	65,618	-	65,618	-	-
Interest	-	2,053	-	2,053	-	-
	74,788	**76,841**	**9,170**	**67,671**	**-**	**-**

Contractual cash flows at December 31, 2015 exclude the current portion of unit-based compensation of $227,000.

The following were the contractual undiscounted maturities of financial liabilities, including estimated interest payments, as applicable, at December 31, 2014:

$000's	Carrying amount	Contractual cash flows	Less than one year	One - two years	Two - five years	More than five years
Trade and other payables	8,316	8,316	8,316	-	-	-
Distributions payable	1,068	1,068	1,068	-	-	-
Debt	47,200	47,200	-	47,200	-	-
Interest	-	2,842	-	2,842	-	-
	56,584	**59,246**	**9,384**	**50,042**	-	-

Contractual cashflows at December 31, 2014 exclude the current portion of unit-based compensation of $1,336,000.

The Trust units contain a redemption feature, see note 19 "Trust Capital". Utilizing the terms of redemption as outlined in note 19, the total market redemption price for all outstanding units at December 31, 2015 would be $35,554,103 ($1.13 per unit 10 day volume weighted average price x 90% x 34,863,364 units); and $81,624,880 ($2.59 per unit 10 day volume weighted average price x 90% x 35,017,112 units) at December 31, 2014. As the maximum cash outlay required by the Trust is capped at $100,000 per month or $1,200,000 per year, the Trust would have approximately 30 years to pay out this commitment (68 years at December 31, 2014).

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 many factors including world economic events that dictate the levels of supply and demand and the relationship between the Canadian and United States dollar.

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 December 31, 2015, the Trust has entered into the following financial contracts to mitigate the effects of fluctuating prices on a portion of its production. (see subsequent events note 23 for a summary of financial contracts entered into after December 31, 2015):

	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)	500	bbls/d	Jan-16	Dec-16	65.00	65.00	5,940	-
NYMEX (i)	500	bbls/d	Jan-16	Dec-16	53.32	53.32	2,995	-
Gas Fixed Price								
CGPR ALT daily spot (ii)	1,500	GJs/day	Jan-16	Dec-16	2.83	2.83	223	-
Differential								
Oil Edmonton SW (iii)	1,000	bbls/d	Dec-15	Dec-16	3.65	3.65	4	-
Unrealized risk management asset							**$9,162**	**-**

(i) Represents a fixed price financial swap transaction with a set forward sale price (WTI reference prices).
(ii) Represents a fixed price financial swap transaction with a set forward sale price (Alberta Daily Spot Price Averages).
(iii) Represents a fixed price differential between Edmonton SW Blended oil and WTI.

As at December 31, 2014, the Trust had 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	2,332	-
NYMEX (ii)	1,000	bbls/d	Jan-15	June-15	90.10	92.00	7.317	-
NYMEX (i)	400	bbls/d	Jul-15	Dec-15	87.90	87.90	2,267	-
NYMEX (ii)	400	bbls/d	Jan-15	Jun-15	90.50	94.35	3,003	-
Unrealized risk management asset							**$14,919**	**-**

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

At December 31, 2015, the Trust had committed to the future sale of 366,000 barrels of oil at an average price of $US 59.16 WTI per barrel, the future sale of 549,000 GJs at a price of $2.83/GJ, and an Edmonton Light Sweet - WTI Differential contract of $US 3.65 for 366,000 barrels of oil.

The total net fair value of Eagle's risk management positions at December 31, 2015 is an asset of $9.2 million (December 31, 2014 - $14.9 million asset) and has been calculated using both quoted prices in active markets and observable market-corroborated data consistent with a Level 2 valuation.

As at December 31, 2015, there were no unrealized foreign exchange contracts outstanding (December 31, 2014 - $nil).

A 10% increase (decrease) in the market price of crude oil from its 2015 year average of $US 48.80 WTI would have increased (decreased) income by approximately $1.4 million based on the risk management instruments outstanding at December 31, 2015. A 10% increase (decrease) in the market price of crude oil from its 2014 year average of $US 93.00 WTI would have increased (decreased) income by approximately $1.9 million in 2014. This analysis assumes that all other variables remain constant.

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

	Year ended December 31, 2015			Year ended December 31, 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	(20,714)	7,962	(12,752)	(302)	(15,718)	(16,020)
Net effect - foreign exchange	-	-	-	153	-	153
Net effect - risk management	**(20,714)**	**7,962**	**(12,752)**	**(148)**	**(15,718)**	**(15,867)**

Foreign Exchange Risk

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

The following financial instruments were denominated in US dollars:

As of December 31, 2015 ($000's)	**US**	**CA**
Cash	1,233	1,706
Trade and other receivables	3,023	4,184
Trade and other payables	(3,908)	(5,409)
Risk management asset	6,455	8,934
	6,803	**9,415**

The average exchange rate during the year ended December 31, 2015 was $US 1 equal to $CA 1.28, and the exchange rate at December 31, 2015 was $US 1 equal to $CA 1.38.

A 10% strengthening (weakening) of the Canadian dollar against the US dollar from its 2015 year average of $CA 1.28 ($US 0.78) would have decreased (increased) income by approximately $1.6 million. This analysis assumes that all other variables remain constant.

As of December 31, 2014 ($000's)	**US**	**CA**
Cash	7,824	9,077
Trade and other receivables	5,488	6,366
Trade and other payables	(6,009)	(6,971)
Risk management asset	12,860	14,919
	20,163	**23,391**

The average exchange rate during the year ended December 31, 2014 was $US 1 equal to $CA 1.10, and the exchange rate at December 31, 2014 was $US 1 equal to $CA 1.16.

A 10% strengthening (weakening) of the Canadian dollar against the US dollar from its 2014 year average of $CA 1.10 ($US 0.90) would have decreased (increased) income by approximately $2.6 million. This analysis assumes that all other variables remain constant.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. As at December 31, 2015, $65.6 million ($US 47.4 million) had been drawn against the revolving $110.7 million ($US 80 million) credit facility. Borrowings are by way of Banker's Acceptance (BAs) and prime rate loans. The carrying value of the Trust's debt outstanding on its revolving credit facility approximates its fair value and is consistent with a Level 2 valuation. See note 17 "Debt". At December 31, 2015 and December 31, 2014, there were no covenant violations to the loan agreement.

A 1% increase (decrease) in the interest rate would have decreased (increased) income by approximately $0.5 million based on an average outstanding total debt balance of $51.7 million for the period ended December 31, 2015.

A 1% increase (decrease) in the interest rate would have decreased (increased) income by approximately $0.6 million based on an average outstanding total debt balance of $57.5 million for the period ended December 31, 2014.

Capital Management

The Trust's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Trust manages its capital structure and makes adjustments to it based upon economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include working capital, loans and borrowing, and unitholders' equity. In order to maintain or adjust the capital structure, the Trust may issue units, engage in external debt financing, and adjust its capital spending, cost structure and distribution levels to manage current and projected debt levels. The Trust monitors capital based on the ratio of external debt to cash generated from operations. This ratio is calculated as external debt, defined as outstanding loans and borrowings, plus or minus working capital deficit or surplus divided by cash generated from operations before changes in non-cash working capital. The Trust prepares annual capital expenditure budgets which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at December 31, 2015, the Trust's ratio of external debt to cash flow was within the range targeted by the Trust.

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

Draws against the existing credit facility are subject to established covenants. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves. See note 17 "Debt".

5. Subsidiaries and Consolidated Entities

The following table summarizes the structure of the Trust as at December 31, 2015. All subsidiaries of the Trust are directly or indirectly wholly-owned by the Trust. Refer to note 23 "Subsequent Events" for details of changes to the structure of the Trust that occurred on January 27, 2016. The following is a description of the subsidiaries of the Trust as at December 31, 2015:

Subsidiary	Country of Formation	Nature of Business
Eagle-Coda Petroleum Inc.	Canada	Alberta Corporation
Eagle Energy Canada Inc.	Canada	Alberta Corporation
1857515 Alberta Ltd.	Canada	Alberta Corporation
Eagle Energy Holdings Inc.	Canada	Alberta Corporation
Eagle Hydrocarbons Inc.	United States	Delaware Corporation
Eagle Energy Commercial Trust	Canada	Alberta Trust

The results of the above subsidiaries, together with Eagle Energy Inc. (as further described below) have been included in the consolidated financial statements in accordance with IFRS 10 - Consolidation. All of the entities have December 31 year ends.

Eagle Energy Inc. is the Administrator of the Trust and was formed under the laws of the Province of Alberta on March 28, 2008. The sole shareholder of Eagle Energy Inc. is EEI Holdings Inc. and the sole shareholder of EEI Holdings Inc. is Richard Clark, President, Chief Executive Officer and a director of the Administrator. Eagle Energy Inc. is not a legal subsidiary of the Trust.

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

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

Eagle Energy Inc. is a structured entity that has been designated so that voting or similar rights are not the dominant factor in deciding who controls the entity. The relevant activities of Eagle Energy Inc. are directed by means of contractual arrangements. These contractual arrangements give the Trust the current ability to direct the relevant activities of Eagle Energy Inc. As such, Eagle Energy Inc. has been consolidated in these financial statements.

6. Business Combinations

On August 20, 2015, Eagle closed the acquisition of a private company by acquiring all of the issued and outstanding common shares of the private company for cash consideration of $0.06 per share and assumption of the acquired company's net debt. This acquisition has been accounted for as a business combination under IFRS 3, using a credit adjusted risk free rate of 10% to calculate the fair value of the decommissioning liability.

From August 20, 2015 to December 31, 2015, the assets acquired have contributed revenues of $2.9 million and operating income of $0.5 million. Had the acquisition closed on January 1, 2015, estimated contributed revenues would have been $11.3 million and estimated contributed operating income would have been $4.1 million to December 31, 2015.

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

On December 18, 2014 (with an effective date of January 1, 2015), the Trust acquired a 50% non-operated working interest in producing properties in the Dixonville Montney "C" oil pool located in north central Alberta for cash consideration of $100.9 million.

The acquisition has been accounted for as a business combination with the fair value of the net assets as follows:

Identifiable assets acquired and liabilities assumed ($000's):	
Oil and gas properties	101,294
Decommissioning liabilities	(384)
	100,910

7. Segmented Information

Eagle's reportable segments are determined based on the Trust's operations and geographic locations as follows:

- Canadian operations - includes oil and gas exploration, development and the sale of hydrocarbons and related activities in Canada.
- United States operations - includes oil and gas exploration, development and the sale of hydrocarbons and related activities in the continental United States.

- Corporate - Eagle has a corporate head office in Calgary, Alberta and a corporate office in Houston, Texas. Costs incurred in the corporate segment relate to hedging and other expenses incurred in overall financing and management of the Trust.

The Canadian operations segment arose due to the acquisition of Eagle's first Canadian property, the Dixonville assets in Alberta, effective January 1, 2015. In addition, the Trust closed an acquisition of assets in the Twining area of Alberta on August 20, 2015. See note 6 "Business Combinations" for details of the Twining acquisition. The segmented operations include 12 months of the Dixonville results and 4.3 months of the Twining results.

Using the segmented information, the Trust's management reviews the financial performance of each segment by assessing the funds flow from operations and other key performance indicators.

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:

	Year Ended December 31, 2015			
$000's	**Canada**	**United States**	**Corporate**	**Total**
Capital expenditures	**31,112**	**14,053**	**-**	**45,165**
Revenue	21,052	42,260	-	63,312
Royalties	(3,136)	(12,055)	-	(15,191)
Revenue net of royalties	17,916	30,205	-	48,121
Operating expenses	9,150	12,958	-	22,108
Transportation and marketing expenses	2,243	111	-	2,354
	6,523	**17,136**	**-**	**23,659**
Administrative expenses	3,376	6,305	1,518	11,199
Cash settled award payments	-	-	207	207
Risk management loss (gain) - realized	-	-	(20,714)	(20,714)
Finance expense (cash portion)	-	-	2,045	2,045
Income tax recovery	-	(46)	-	(46)
Realized foreign exchange loss	-	-	230	230
Funds flow from operations	**3,147**	**10,877**	**16,714**	**30,738**

In the United States segment, revenue for 2015 was received primarily from two customers, Sunoco Logistics Partners L.P. ("Sunoco") and Plains Marketing L.P. ("Plains"), with revenue received amounting to $21.5 million (51%) and $6.0 million (14%) respectively. In the Canadian segment, revenue for the year was received primarily from Spyglass Resources Corp., the operating partner in the Dixonville properties, in the amount of $18.9 million (90%). Beginning with September 1, 2015 production, Eagle began taking its oil revenue in kind for the Dixonville properties. Eagle operates or takes in kind the majority of its revenue from the Twining properties acquired on August 20, 2015.

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

	Year Ended December 31, 2015			
$000's	**Canada**	**United States**	**Corporate**	**Total**
Funds flow from operations	**3,096**	**10,877**	**16,764**	**30,738**
Unit based compensation - non-cash portion	-	-	(1,089)	(1,089)
Risk management loss - unrealized	-	-	7,962	7,962
Depreciation, depletion and amortization	6,067	20,329	-	26,396
Impairment	47,487	39,768	-	87,255
Foreign exchange gain on intercompany loan	-	-	(14,668)	(14,668)
Finance expense (non-cash portion)	-	-	928	928
Earnings (loss)	**(50,458)**	**(49,220)**	**23,632**	**(76,046)**

Total assets of the Trust's reportable segments at December 31, 2015 were as follows:

	Year-Ended December 31, 2015			
$000's	**Canada**	**United States**	**Corporate**	**Total**
Total Assets	**110,657**	**88,753**	**9,162**	**208,572**

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

8. Unit-based Payments

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

$000's	Note	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
Restricted Unit Rights	8(a)	174	(515)
Unit Options	8(b)	(750)	(6,067)
Unit Rights	8(c)	(306)	(1,018)
Total unit-based compensation expense (recovery)		**(882)**	(7,600)

The following table reconciles the unit-based payments liability:

$000's	Note	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
Restricted Unit Rights	8(a)	6	61
Unit Options	8(b)	183	932
Unit Rights	8(c)	38	343
Total unit-based payments liability		**227**	1,336

Grant, Surrender and Replacement of Performance Options

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

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

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

Note (a)

Cash settled Restricted Unit Rights (RURs) Issued upon Surrender of Performance Options

At December 31, 2015, all RURs had vested. Each RUR entitles the holder to receive cash payments equal to the distributions payable on one unit as well as capital appreciation of units. For the year ended December 31, 2015, an aggregate of $227,685 has been paid to the RUR holders (year ended December 31, 2014 - $664,072).

The fair value estimate associated with the RURs is expensed or recovered in the income statement with the offsetting entry to unit-based payments liability. At December 31, 2015, the fair value of the RURs was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period with the corresponding change to fair value being recognized in the income statement.

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

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

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

	Year Ended December 31, 2015	Year Ended December 31, 2014
Fair value at the balance sheet date ($)	0.01	0.10
Volatility (%)	39	36
Life of RURs (years)	5.0	6.0
Risk-free interest rate (%)	1.46	1.83

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

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

The fair value estimate associated with the options is expensed or recovered in the income statement over the vesting period with the offsetting entry to unit-based payments liability. At December 31, 2015, the fair value of the options was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period with the corresponding change to fair value being recognized in the income statement.

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

	Year Ended December 31, 2015		Year Ended December 31, 2014	
	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
Forfeited	(272,332)	6.28	(45,000)	5.51
Exercised	-	-	-	-
Granted	-	-	350,000	5.35
Outstanding at end of period	**3,159,418**	**5.54**	3,431,750	5.94
Exercisable at end of period	**2,601,427**	**5.62**	2,109,095	6.01

The range of exercise prices of the outstanding options is as follows at December 31, 2015:

	Weighted average exercise price	Weighted average contractual life (years)
$4.51 - $7.16	5.54	6.50

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

	Year Ended December 31, 2015	Year Ended December 31, 2014
Fair value - at balance sheet date ($)	0.07	0.37
Unit trading price - closing ($)	1.14	2.33
Exercise price – weighted average ($)	5.54	5.94
Volatility (%)	39	36
Option life – weighted average (years)	6.5	7.6
Risk-free interest rate (%)	1.46	1.83

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

Effective June 14, 2011, the Trust implemented a cash settled Unit Rights ("URs") plan that entitles United States based directors, officers, employees and certain consultants of Eagle Hydrocarbons Inc. to participate.

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

The URs have a 10 year term and vest as to one-third on each of the first, second and third anniversaries of the date of grant. URs granted are not subject to any performance criteria apart from continued service or employment. URs are forfeited if the holder leaves before vesting. Until vested, UR payments will be accrued for the benefit of the holders. Holders of the URs are entitled to receive cash payments on a calendar year basis once the URs vest.

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

The fair value estimate associated with the URs is expensed or recovered in the income statement over the vesting period with the offsetting entry to unit-based payments liability. At December 31, 2015, the fair value of the URs was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period with the corresponding change to fair value being recognized in the income statement.

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

	Year Ended December 31, 2015	Year Ended December 31, 2014
Balance, beginning of period	937,000	997,000
Issued	-	-
Forfeited	(283,500)	(60,000)
Balance, end of period	653,500	937,000
Number of unit rights vested	524,505	465,007

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:

	Year Ended December 31, 2015	Year Ended December 31, 2014
Fair value at the balance sheet date($)	0.06	0.50
Volatility (%)	39	36
Life of PURs (years)	7.2	8.1
Risk-free interest rate (%)	1.46	1.83

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.

9. Foreign Exchange

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

$ 000's	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Net loss arising on settlement of foreign currency transactions arising out of operating activities	230	56
Foreign exchange loss (gain) on intercompany loan	(14,668)	-
Foreign exchange loss (gain) net	**(14,438)**	56

In 2014, the currency in which these transactions and balances are primarily denominated is US dollars. As a result of the Trust's US subsidiary disposing of its Permian Basin assets and using the proceeds to partially repay its intercompany loan owing to the Trust (with the Trust then using the proceeds to indirectly acquire Canadian properties) the intercompany loan was no longer regarded as part of the Trust's "net investment" in its subsidiary. The effect of this change in circumstance on the financial statements is that foreign exchange gains or losses on the value of the Canadian denominated intercompany loan are recorded in the income statement during 2015 (rather than in the cumulative translation adjustment account). See note 4 “Financial Risk Management and Financial Instruments”.

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

$000’s	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Beginning balance	29,494	11,100
Foreign currency translation gain (loss)	6,121	18,394
Ending balance	**35,615**	29,494

10. Finance Expense

$000’s	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Interest expense on debt	1,729	2,026
Amortization of deferred financing costs	529	389
Standby and bank fees	316	162
Accretion of decommissioning provision	399	78
Finance expense	**2,973**	2,655

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11. Taxation

Reconciliation of Effective Tax Rate

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

$000's	**Year Ended December 31, 2015**	Year Ended December 31, 2014
(Loss) Earnings before taxation	(76,092)	(47,818)
Expected tax rate (%)	26	35
Expected income tax provision	(19,784)	(16,736)
Decrease (Increase) resulting from:		
Non-deductible items – permanent differences		
Administrative expenses of the Trust	390	712
Unit-based compensation	(175)	(2,660)
Foreign exchange loss (gain), net	(9,936)	10
Foreign tax rate differentials	(4,208)	-
Change in statutory rate(1)	(542)	-
Changes in temporary differences for which no amounts are recognized	36,543	23,393
Return to provision true up	-	55
Items deductible at the subsidiary level		
Interest on internal debt of subsidiary	(2,392)	(5,877)
Realized foreign exchange gain	-	2,919
Other	58	(1,606)
Total income tax expense(2)	**(46)**	210

(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	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Deferred tax liabilities		
United States	(8,330)	3,422
Canada	(16,210)	-
	(25,040)	3,422
Less deferred tax assets		
Non-capital losses - United States	(42,447)	(32,216)
Non-capital losses - Canada	(16,298)	-
	(58,745)	(32,216)
Net deferred tax liability(asset) – before valuation allowance	(83,785)	(28,794)
Unrecognized deferred tax asset	83,785	28,794
Net deferred tax liability (asset)	**-**	-

Movement in Temporary Differences during the Year:

$000's	Statement of Earnings		Balance Sheet	
For the year ended December 31,	**2015**	2014	**2015**	2014
Oil and gas properties	(28,462)	(18,018)	(25,040)	3,422
Deferred Tax on Acquisition	18,448	-	-	-
Non-capital tax losses - U.S. based	(26,529)	(5,375)	(58,745)	(32,216)
	(36,543)	**(23,394)**	**(83,785)**	(28,794)

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

12. Depreciation, Depletion and Impairment

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

	Year Ended December 31, 2015		
$000's	Oil and gas properties	Property, plant and equipment	Total
Depreciation, depletion and amortization	26,221	175	26,396
Impairment	87,255	-	87,255
	113,476	**175**	**113,651**

	Year Ended December 31, 2014		
$000's	Oil and gas properties	Property, plant and equipment	Total
Depreciation, depletion and amortization	35,659	187	35,846
Impairment	69,531	-	69,531
	105,190	187	105,377

Impairment of Oil and Gas Properties

For the year ended December 31, 2015, the Trust recognized a $87.3 million impairment on its oil and gas properties in relation to the Salt Flat, Hardeman, Dixonville and Twining CGUs. For the year ended December 31, 2014, the Trust recognized a $69.5 million impairment on its oil and gas properties in the Salt Flat CGU. The impairment was primarily a result of (i) the decrease in forecast benchmark commodity prices at December 31, 2015 compared to December 31, 2014, and (ii) a higher risk adjusted discount rate of 11% for Salt Flat and Hardeman compared to a discount rate of 10% used for these properties at December 31, 2014.

13. Employees and Key Management

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

$000's	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Salaries and wages	7,493	7,140
Benefits and other personnel costs	1,331	746
Unit-based payments (i)	(825)	(6,130)
Total employee and executive remuneration	**7,999**	1,756

(i) Represents the amortization of unit based compensation as recorded in the financial statements. See Note 8 "Unit-based payments".

Key management personnel include the Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, the Vice-Presidents, the General Counsel/Corporate Secretary and the external Directors. The aggregate remuneration of key management personnel was as follows:

$000's	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Directors' fees	236	255
Salaries and wages	3,213	3,241
Benefits and other personnel costs	266	175
Unit-based payments (i)	(680)	(6,638)
Total key management executive remuneration	**3,035**	(2,967)

(i) Represents the amortization of unit based compensation (recovery) as recorded in the financial statements. See note 8 "Unit-based payments".

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

Key management personnel are entitled to certain amounts and benefits payable in the event of termination of their employment without cause and in the event of a change of control, as outlined in their respective employment agreements.

In the event of termination without just cause, 18 months' salary is payable in the case of the Chief Executive Officer, 12 months' salary in the case of the Chief Financial Officer, Chief Operating Officer, Vice President Corporate and Business Development and Vice President Capital Markets and Business Development and 6 months' salary in the case of the General Counsel/Corporate Secretary. In addition, in the event of termination without just cause, in the case of the Chief Executive Officer and the Chief Financial Officer, the amount of the last annual bonus received is payable. In the event of termination without just cause of the other officers, a pro-rata portion of the annual discretionary bonus that he or she would have been entitled to receive for the calendar year in which his or her employment was terminated is payable.

In the event of a change of control as defined in the employment agreement, each is entitled to the severance described above if (i) his or her employment is subsequently or contemporaneously terminated without just cause within 12 months of the date of a change of control; (ii) he or she does not continue to be employed as the same level of responsibility or level of compensation and elects within 12 months of the date of the change of control to treat his or her employment as being terminated as a result of such reduction; or (iii) the person elects for any reason to terminate his or her employment within 12 months of the date of the change of control.

14. Loss per Unit

$000's	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Earnings (loss) attributable to unitholders - basic	(76,046)	(48,028)
Earnings (loss) attributable to unitholders - diluted (i)	(76,046)	(52,350)
Weighted average number of units outstanding - basic	34,691	33,676
Weighted average number of units outstanding - diluted	34,691	33,811
Earnings (loss) per unit - basic	**(2.18)**	(1.43)
Earnings (loss) per unit - diluted	**(2.18)**	(1.55)

(i) The unit option plan awards can be exchanged for common units of the Trust, and are considered potentially dilutive. They are included in the calculation of the Trust's diluted net earnings per unit if they have a dilutive impact in the period. Accounting for these awards as equity-settled was not determined to have an anti-dilutive impact for the year ended December 31, 2015. Included in the diluted number of units outstanding for the year ended December 31, 2014 is the effect of 135,602 units issuable under the 3,431,750 options outstanding under the unit option plan.

Calculation

Basic income per unit for the year ended December 31, 2015 is calculated by dividing the income attributable to unitholders of the Trust by the weighted average number of units outstanding during the period. Diluted income per unit is calculated using the income for the period divided by the weighted average number of units outstanding adjusted for the effects of all potentially dilutive units.

15. Exploration and Evaluation Assets

$000's	**December 31, 2015**	December 31, 2014
Beginning balance	-	508
Additions	1,033	-
Transferred to oil and gas properties	-	(409)
Expense	-	(154)
Foreign exchange adjustment	-	55
Ending balance	**1,033**	-

During 2015, $1.0 million was incurred to evaluate seismic on lands which the Trust holds a right to explore to assess the potential to add value and reserves.

At December 31, 2015, the Trust expensed $Nil (December 31, 2014 - $0.2 million) of exploration and evaluation assets related to projects that were not commercially viable and for which the Trust did not receive an assignment of economical recoverable reserves.

16. 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	23,335	1,524	-	24,859
Acquisition, net	35,378	-	-	35,378
Effects of foreign exchange	49,543	1,540	-	51,083
At December 31, 2015	**473,496**	11,046	**-**	**484,542**
Accumulated depreciation, depletion and amortization				
At December 31, 2014	(89,354)	(4,242)	(56,687)	(150,283)
Impairment	-	-	(87,255)	(87,255)
Depreciation	(38,613)	(1,457)	12,152	(27,918)
Effects of foreign exchange	(17,245)	(819)	(14,163)	(32,227)
At December 31, 2015	**(145,212)**	**(6,518)**	**(145,953)**	**(297,683)**
Net book value				
At December 31, 2014	275,886	3,740	(56,687)	222,939
Net change for the period	52,398	788	(89,266)	(36,080)
At December 31, 2015	**328,284**	**4,528**	**(145,253)**	**186,859**

$000's	Developed oil and gas assets	Production facilities and equipment	Impairment	Total
Cost				
At December 31, 2013	395,348	7,106	-	402,454
Additions	68,651	876	-	68,527
Acquisition, net	106,791	-	-	106,791
Disposals	(205,550)	-	-	(205,550)
At December 31, 2014	**365,240**	**7,982**	**-**	**373,222**
Accumulated depreciation, depletion and amortization				
At December 31, 2013	(67,029)	(3,999)	(7,077)	(78,105)
Impairment	-	-	(73,009)	(73,009)
Depreciation	(43,935)	(1,721)	-	(45,656)
Disposals	21,610	1,478	23,399	46,487
At December 31, 2014	**(89,354)**	**(4,242)**	**(56,687)**	**(150,283)**
Net book value				
At December 31, 2013	328,319	3,107	(7,077)	324,349
Net change for the period	(52,434)	633	(49,610)	(101,410)
At December 31, 2014	**275,886**	**3,740**	**(56,687)**	**222,939**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $40.3 million (December 31, 2014 - $42.9 million) were included in the depletion calculation.

2015 additions to "Developed oil and gas assets" include the Twining property acquisition. See note 6 "Business Combinations".

Impairment Provision

The Trust recognized impairment charges during 2015. See note 12 "Depreciation, Depletion, and Impairment".

The recoverable amount of the Salt Flat CGU was calculated as $32.6 million, the Hardeman CGU was calculated as $29.6 million, the Dixonville CGU was calculated as $69.6 million, and the Twining CGU was calculated as $27.4 million based on the greater of the value in use and the fair value less costs to dispose. To determine fair value less costs to dispose, the Trust considered recent transactions within the industry, long-term views of commodity prices, externally evaluated reserve volumes and discount rates specific to the CGU. The Salt Flat, Hardeman and Twining CGUs were calculated at an 11% discount rate and the Dixonville CGU was calculated at 11.6%.

The calculation of the recoverable amount is sensitive to the assumptions regarding production volumes, discount rates and commodity prices. A 1% increase (decrease) in the discount rate would have decreased (increased) the fair value estimate by approximately $12.9 million. In addition, a 10% increase (decrease) in the estimated future cash flows would have increased (decreased) the fair value estimate by $23.7 million.

The following commodity price estimates were used in determining whether an impairment to the carrying value of the CGUs existed at December 31, 2015:

	WTI Oil ($US/bbl)	***Edmonton Light Crude ($CA/bbl)***	***Henry Hub Gas ($US/MMBtu)***	***AECO Spot Gas ($CA/MMBtu)***
2016	45.00	56.60	2.50	2.70
2017	53.60	66.40	2.95	3.20
2018	62.40	72.80	3.40	3.55
2019	69.00	80.90	3.70	3.88
2020	73.10	83.20	3.90	3.95
2021	77.30	88.20	4.15	4.20
2022	81.60	93.30	4.35	4.45
2023	86.20	98.70	4.60	4.70
2024	87.90	100.70	4.70	4.80
2025	89.60	102.60	4.80	4.90
Escalate thereafter at	2.0%/year	2.0%/year	2.0%/year	2.0%/year

17. Debt

The Trust has a credit facility with a syndicate of Canadian chartered banks. The credit facility is used for general corporate purposes, including working capital, capital expenditures and future acquisitions. As at December 31, 2015, the authorized borrowing base of Eagle's credit facility was $US 80 million with a maturity date of May 26, 2017. The credit facility is secured by a first priority security interest on substantially all of the property and assets of Eagle Hydrocarbons Inc., Eagle Energy Canada Inc. and Eagle-Coda Petroleum Inc. (each a borrower under the credit facility), including all of their respective oil and natural gas properties, and substantially all of the property and assets of Eagle Energy Trust, its other subsidiaries and the administrator of Eagle Energy Trust. Credit facility obligations are also guaranteed by the Trust, its subsidiaries and the administrator of Eagle Energy Trust.

Amounts drawn on the credit facility can be denominated in U.S. or Canadian dollars and may be used for activities in either the U.S. or Canada. The credit facility provides for borrowing by way of LIBOR and base rate loans for amounts drawn in U.S. funds and bankers' acceptances and prime rate loans for amounts drawn in Canadian funds. The margins above base rate, prime rate, LIBOR and bankers' acceptance rate, as applicable, for the credit facility are subject to a pricing grid based on the then applicable ratio of consolidated debt to EBITDAX (the "**Margin Ratio**"). The credit facility documentation also provides for (i) a standby fee for each lender calculated on the lesser of (a) the unused amount of such lender's commitment and (b) the unused amount of such lender's pro rata share of the borrowing base then in effect, at a percentage based on the applicable Margin Ratio and (ii) an issuance fee on the outstanding amount of any letter of credit equal to the margin applicable to LIBOR loans (subject to a reduction in fees for non-financial letters of credit).

The credit facility is subject to semi-annual redetermination of the borrowing base by the credit facility lenders no later than May 15 and October 16 of each year. Borrowing base redeterminations are based on, among other things, the proven reserves of Eagle Hydrocarbons Inc., Eagle Energy Canada Inc. and Eagle-Coda Petroleum Inc.

Under the credit facility, the Trust is required to satisfy certain customary affirmative and negative covenants (including financial covenants). The credit facility documentation provides for customary negative covenants which, among other things, limit the Trust in making distributions to its unitholders if any default, event of default or borrowing base deficiency has occurred and is continuing or would result from such distribution, or if the cash distributions made for the trailing four quarters exceeds the Available Distributable Cash Flow (as defined by the credit facility agreement which was $33.9 million at December 31, 2015 for the trailing four quarters. The credit facility documentation also includes other customary restrictive covenants including limitations on indebtedness, liens, contingent obligations, investments, dispositions, mergers, consolidations, liquidations and dissolutions. In addition, the Trust must maintain, as at the end of each fiscal quarter, a minimum current ratio (being the ratio of current assets plus the unused availability under the credit facility less cash subject to restriction and risk management assets and other assets resulting from a mark-to-market valuation is to current liabilities less the current portion of long-term debt and risk management liabilities and other liabilities resulting from a mark-to-market valuation) of not less than 1.00 to 1.00, a minimum four quarter trailing interest expense coverage ratio (being the interest expense for the trailing four quarters divided into the four quarter trailing EBITDAX) of not less than 3.00 to 1.00. "Interest expense" is defined in the credit facility as the sum of (a) all interest, premium payments, debt discount, fees, charges and related expenses in connection with debt (including capitalized interest and amortization of debt discount) to the extent treated as interest in accordance with IFRS, and (b) the portion of rent expense with respect to such period under capital leases that is treated as interest in accordance with IFRS.

The Trust must also maintain, at the end of each fiscal quarter, a maximum debt to four quarter trailing EBITDAX ratio of 3.00 to 1.00. Under the credit facility, "**EBITDAX**" means, calculated for such period:

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

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

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

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

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

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

In addition, EBITDAX is calculated after giving effect on a pro-forma basis to any permitted acquisition or asset disposition as if such acquisition or disposition occurred at the beginning of such period.

Failure to comply with any of these financial covenants, as well as any of the other affirmative and negative covenants, would result in an event of default, which, if not cured or waived, would permit acceleration of the indebtedness pursuant to the credit facility. In the event that a borrowing base redetermination results in a reduction of the authorized credit facility below the amount outstanding under the credit facility (such that a "borrowing base deficiency" exists) the credit facility instructs that Eagle must elect to take any one or a combination of the following actions: (1) Repay the borrowing base deficiency within 10 days; (2) pledge additional acceptable collateral such that the borrowing base deficiency is cured within 30 days; (3) deliver an election in writing to the lender to agree to repay borrowing base deficiency in six monthly installments equal to one-sixth of such borrowing base deficiency with the first such installment due thirty (30) days after the date such deficiency notice was received by Eagle. At December 31, 2015, there were no covenant violations under or in connection with the credit facility.

At December 31, 2015, details of the Trust's credit facility are as follows:

$000's	**$US**	**$CA**
Authorized (revolving)	80,000	110,720
Less:		
Amounts drawn	47,412	65,618
Available	**32,588**	**45,102**

The exchange rate in effect at December 31, 2015 was $US 1 equal to $CA 1.38 (December 31, 2014 - $US 1 equal to $CA 1.06). The amount drawn on the credit facility at December 31, 2015 is denominated in Canadian funds.

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

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

18. Decommissioning Liability

$000's	Year Ended December 31, 2015	Year Ended December 31, 2014
Beginning balance	10,347	3,036
Acquisition - see note 6 "Business Combinations"	3,187	472
Additions	251	344
Change in estimate due to acquired properties	9,011	-
Other changes in estimates	3,274	7,981
Disposition	-	(1,189)
Abandonment expenditures	-	(212)
Accretion (unwinding of discount)	399	78
Effects of exchange rate	529	(163)
Ending balance	**26,998**	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% inflation rate), and discounted using a risk-free discount rate of 1.39% (December 31, 2014 – 2%) for the Salt Flat properties, 2.15% for the Hardeman and Dixonville properties (December 31, 2014 - 2.7% for Hardeman and Permian properties) and 1.39% for the Twining properties. A 1% decrease in the risk-free discount rate would have increased the liability by $9.4 million as at December 31, 2015 (December 31, 2014 - $3.2 million). The total undiscounted amount of the estimated cash flows required to settle the obligation was $38.0 million (December 31, 2014 - $28.2 million).

When the Twining properties were acquired, a valuation of the decommissioning asset was made using a risk free rate of 10%. A change in estimate occured when the decommissioning asset was booked using a risk free rate of 1.39%.

Included in the balance at December 31, 2015 is $9.1 million of decommissioning liability recorded as part of the property acquisitions. See note 6 "Business Combinations".

19. Trust Capital

Refer to note 23 "Subsequent Events", where the January 27, 2016 acquisition and conversion of the Trust to a corporate structure is described. The following is a description of the capital of the Trust as at December 31, 2015.

Authorized

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

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

At December 31, 2015, the Trust units outstanding were as follows:

Trust Units Outstanding

	Year Ended December 31, 2015		Year Ended December 31, 2014	
	Number of units (000's)	**Amount ($000's)**	Number of units (000's)	Amount ($000's)
Beginning balance	35,017	317,150	32,149	297,447
Issuance of Trust capital pursuant to DRIP	36	67	2,868	17,421
Cancellation of Trust capital pursuant to NCIB	(190)	(1,833)	-	-
Fair value adjustment	-	-	-	2,319
Trust unit issuance costs	-	(5)	-	(37)
Ending balance	**34,863**	**315,379**	35,017	317,150

The Trust incurred approximately $5,000 of issuance costs associated with the DRIP.

For the year ended December 31, 2015, the Trust issued 36,552 units at a weighted average price of $1.84 per unit for total gross proceeds of $67,245 pursuant to the DRIP as described below.

For the year ended December 31, 2015, the Trust purchased 190,300 units at a weighted average market price of $2.36 per unit pursuant to the Normal Course Issuer Bid ("NCIB") as described below.

DRIP Plan (Premium Distribution and Distribution Reinvestment Plan) and NCIB

Commencing with the distribution paid on February 23, 2015, for unitholders of record on January 30, 2015, Eagle's DRIP was suspended until further notice. Unitholders who had elected to participate in the DRIP received cash distributions on future distribution payment dates.

The Distribution Reinvestment Plan (the "Plan") provided eligible unitholders with the opportunity to reinvest their monthly cash distributions in new trust units at a discount to the average market price (as defined in the Plan) on the applicable distribution payment date. Commencing with the distribution paid on October 23, 2014, the Trust suspended the Premium Distribution™ component of the Plan and amended the Plan to reduce the market discount that Trust units can be acquired for under the regular distribution reinvestment component from 5% to 2%. Commencing with the distribution paid on February 23, 2015, the Trust also suspended the regular distribution reinvestment component of the Plan.

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. 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 the TSX's NCIB rules.

Purchases made by Eagle were at the prevailing market price of the Units at the time of purchase and were 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 were 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 the Plan, Eagle's broker repurchased 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 made by Eagle's broker were based on the parameters prescribed by the TSX and the terms of the Plan. The Plan was in place for the one-year period of the NCIB.

20. Accumulated Cash Distributions

$000's	**December 31, 2015**	December 31 2014
Beginning balance	(116,315)	(80,454)
Accumulated cash distributions	(12,058)	(33,524)
Fair market value of units issued under the DRIP	18	(2,337)
Total accumulated cash distributions	**(128,355)**	(116,315)

In accordance with IFRS 13, at December 31, 2015, the Trust recorded a non-cash fair value adjustment of $17,921 (December 31, 2014 - $2.3 million) for units issued under the DRIP.

21. Related Party Disclosures

The Trust has no party holding voting control.

Key Management

Key management personnel include the Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, the Vice-Presidents, General Counsel/Corporate Secretary and the external Directors. Refer to note 13 "Employees and Key Management".

Intercompany Transactions

There are certain intercompany transactions among the subsidiaries comprising these consolidated financial statements of the Trust. Other than realized foreign exchange gains or loses, transactions have been eliminated in consolidation.

22. 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 25 months and approximately $1.0 million remaining at December 31, 2015.

Operating Lease Commitment - Sublease in Calgary, Alberta

On August 20, 2015, concurrent with the closing of the acquisition of a private company, the Trust assumed an obligation for the private company's office lease. The term of the lease is from March 1, 2011 to February 28, 2017. Future minimum lease payments during the term of the lease approximate $1.4 million, with 14 months and approximately $0.3 million remaining at December 31, 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 24 months and approximately $US 0.60 million remaining at December 31, 2015. In $CA the remaining future minimum lease payments approximate $0.8 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.38.

Legal Proceedings

The Trust is involved in various litigation and claims in the normal course of the Trust's operations. Although the outcome of these claims cannot be predicted with certainty, the Trust does not expect these matters to have a material adverse effect on Eagle's financial position, cash flows or results of operations. If an unfavorable outcome were to occur, there exists the possibility of a material adverse impact on the Trust's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Trust determines that the loss is probable and the amount can be reasonably estimated. The Trust believes it has made adequate provision for such legal claims.

23. Subsequent Events

Acquisition and Conversion to a Corporate Structure

On January 27, 2016, the Trust closed the plan of arrangement (the "Arrangement") involving the acquisition, by way of share exchange, of Maple Leaf Royalties Corp. ("Maple Leaf") and conversion of the Trust into a corporate structure. The resulting public entity, named Eagle Energy Inc., is listed on the Toronto Stock Exchange with its common shares trading under the symbol "EGL". After the Arrangement, former unitholders of Eagle Energy Trust held approximately 82% of the 42,451,623 outstanding common shares of Eagle Energy Inc. Concurrently, the unitholders of the Trust and the shareholders of Maple Leaf approved the adoption by Eagle Energy Inc. of a new long-term equity compensation incentive plan for Eagle's directors, officers, employees and consultants. Holders of options to purchase Eagle Energy Trust Units had their option agreements adjusted to entitle them to purchase shares of Eagle Energy Inc. on identical terms and conditions. All outstanding options to purchase shares of Maple were terminated.

Pursuant to the Arrangement, Eagle Energy Trust units were exchanged for Eagle Energy Inc. common shares on a one-for-one basis, which resulted in 34,863,364 Eagle Energy Inc. common shares being issued. In addition, Eagle Energy Inc. acquired all of the issued and outstanding common shares of Maple Leaf on the basis of 0.0947 of a common share of Eagle Energy Inc. being issued for each outstanding common share of Maple Leaf, which resulted in 7,141,815 Eagle Energy Inc. common shares being issued. Based on the January 27, 2016 closing price of $0.73 per share, the total value of the common shares issued to acquire Maple Leaf was $5,213,525. At the time of closing, Maple Leaf had no debt and no working capital deficiency. The acquisition of Maple Leaf is expected to add approximately 235 boe/d of royalty interest production and 161 boe/d of working interest production from assets located in Alberta. Estimated cash expenses of the transaction incurred by each of Eagle and Maple Leaf in respect of the Arrangement were $700,000 and $450,000, respectively. In addition, Eagle Energy Inc. issued 446,444 common shares (valued at $325,904 based on the closing price of $0.73 per share) to terminate the Maple Leaf management agreement.

Risk Management

Subsequent to year end, Eagle entered into four additional fixed price financial swap transactions for a total of 183,600 barrels of oil for 2016 at an average price of $US 38.33 WTI per barrel.

Corporate Information

Board of Directors

David M. Fitzpatrick
Chairman of the Board

Bruce K. Gibson [1]
Director

Warren D. Steckley [2][3]
Director

Richard W. Clark
President, Chief Executive Officer and Director

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

TSX: EGL

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

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