2000 – 10423 101 St NW, Edmonton, AB
T5H 0E8 Canada
epcor.com

May 1, 2018

Alberta Utilities Commission
10th Floor, 10055 – 106 Street
Edmonton, AB T5J 2Y2

Attention: **Mr. Blair Miller**
Executive Director, Rates

Dear Mr. Miller:

Re: EPCOR Energy Alberta GP Inc.
Rule 005 – Annual Reporting Requirements of Financial and Operational Results for 2017.

1. EPCOR Energy Alberta GP Inc. ("EEA") provides the attached copy of its Alberta Utilities Commission ("AUC") Rule 005 Annual Financial and Operating Report package for 2017.

2. The package includes the following files:

Appendix A – Financial and Operational Results Schedules
Appendix B – Variance Explanations
Appendix C – Audited Financial Statements for EEA LP

3. Please contact me at 780-412-3335 if you have any questions.

Sincerely,

[Electronically Submitted]

Tammy Haydey MBA, CMA
Controller, Energy Services
EPCOR Energy Alberta GP Inc.

Attachments

EPCOR Energy Alberta GP Inc.

AUC RULE 005: ANNUAL REGULATED RATE TARIFF (RRT) FINANCIAL AND OPERATIONAL RESULTS

FOR THE YEAR ENDED DECEMBER 31, 2017

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Purpose of RRT Schedules

Schedule 1 – Net income statement
To provide a high level breakdown of revenues and expenses associated with the provision of the regulated rate tariff electricity services including the net income (or return) achieved by the providers both including and excluding any regulatory cost disallowances.

Schedule 2 – Revenue by customer class
To provide a detailed revenue breakdown of energy, non-energy and flow-through revenue by customer category relevant to each provider.

Schedule 3 – Sites and energy sales by customer class
To provide a breakdown of the average number of sites and energy sales by customer category relevant to each provider.

Schedule 4 - Energy and operating expenses
To provide a detailed breakdown of expenses associated with the provision of regulated retail energy services. Expenses are separated into commodity costs, trading and procurement charges and other non-energy expenses.

Schedule 5 - Debt capital employed and interest expense
To provide actual and allocated debt carrying costs charged to the provider (normally from the parent company) with an adjustment for any regulatory interest cost disallowances.

Schedule 6 - Income tax / PILOT
To provide the detailed tax calculation used to determine the income tax provision or PILOT for the regulated operations of the provider.

Schedule 7 - Capital assets continuity schedule
To provide a summary of capital assets in use and construction work in process (CWIP) assets, including additions, retirements, transfers and any adjustments.

Schedule 8 - Manpower summary
To provide a breakdown of the capitalized and expensed labour costs and human resources as expressed in full time equivalents (FTEs). The costs shown here are embedded in the total operating expense identified in schedule 4.

Schedule 9 – Reserve accounts
To provide a summary of the transactions that occurred in the provider's reserve accounts for the year.

Schedule 10 – Affiliate transactions
To identify transactions with affiliates. Since some providers are not required to report under the inter-affiliate code of conduct (which requires affiliate transaction reporting), this schedule was retained for transparency.

Schedule 11 - Reconciliation from audited income statement to regulatory schedules
To provide a reconciliation from the audited income statement to the regulated rate provider's reported income.

SCHEDULE 1

EPCOR Energy Alberta GP Inc.
REGULATED RATE TARIFF INCOME STATEMENT
FOR THE YEAR ENDED DECEMBER 31, 2017
($000s)

Line No.	Description	Cross-Ref. from	2017	2016	Variance higher/(lower)	Variance %	Variance W/P Ref
	Revenue						
1	Revenue	Sch 2	692,079	693,070	(991)	-0.1%	A
2	Revenue offsets and other adjustments	Sch 2	4,315	4,922	(607)	-12.3%	A
3	Total Revenue		696,394	697,993	(1,598)	-0.2%	
	Expenses						
4	Energy and operating expenses [1]	Sch 4	185,283	211,022	(25,739)	-12.2%	see Sch 4
5	Interest	Sch 5	616	646	(30)	-4.6%	
6	Income tax /Payment in lieu of tax	Sch 6	-	-	-	-	see Sch 6
7	Depreciation & amortization	Sch 7	4,576	4,832	(256)	-5.3%	B
8	Flow-through expenses	Sch 11	486,330	447,581	38,748	8.7%	A (5)
9	Total Expenses		676,804	664,081	12,724	1.9%	
10	**Regulatory net income/(loss)**	Sch 11	**19,590**	**33,912**	**(14,322)**	**-42.2%**	
	Reconciliation						
11	Regulatory net income/(loss)	Sch 11	19,590	33,912	(14,322)	-42.2%	
12	Less: regulatory cost disallowances [1]	Sch 11	239	1,117	(878)	-78.6%	C
13	**Adjusted regulatory net income/(loss)**		**19,351**	**32,794**	**(13,443)**	**-41.0%**	

Notes:

Note 1 2016 figures were restated to correct the Long-Term Disability accrual adjustment.

EPCOR Energy Alberta GP Inc.
REVENUE BY CUSTOMER CLASS
FOR THE YEAR ENDED DECEMBER 31, 2017
($000s)

Line		Cross-	2017										Variance
			Fortis						EDTI			RRT	
No.	Description	Ref.	Residential	Farm	Irrigation	Small Comm	Oil Gas	Lighting	Residential	Small Comm	Lighting	Total	W/P Ref
1	Energy Revenue [1]		62,075	14,639	2,866	22,031	517	173	46,824	19,339	65	168,530	A (1)
2	Final Settlement											(6,869)	A (1)
3	Non-Energy revenue		15,919	1,873	94	1,864	20	457	15,548	1,215	53	37,045	A (3)
4	Flow-through revenue [2]		183,148	58,840	14,007	71,174	1,885	2,813	119,079	41,723	704	493,374	A (2)
5	Sub-total	Sch 1	261,142	75,352	16,968	95,069	2,423	3,444	181,451	62,278	823	692,079	
	Revenue offsets and other adjustments:												
6	Late Payment Charges		1,116	322	73	406	10	15	744	256	3	2,945	
7	Collection & NSF Fees		193	24	2	21	0	6	199	16	1	462	
8	Connection Fees		381	47	5	41	1	11	623	51	2	1,162	
9	Green Power		3	0	0	0	0	0	3	0	0	6	
10	E-Bill Credit		(110)	(14)	(0)	(12)	(0)	(3)	(110)	(9)	(0)	(259)	
11	Total revenue offsets and other adjustment	Sch 1	1,581	379	80	457	11	28	1,459	314	6	4,315	A
12	**Total**	Sch 11										**696,394**	

Line		Cross-	2016										
			Fortis						EDTI			RRT	
No.	Description	Ref.	Residential	Farm	Irrigation	Small Comm	Oil Gas	Lighting	Residential	Small Comm	Lighting	Total	
1	Energy revenue		36,159	17,412	2,216	68,004	823	214	58,374	24,395	75	207,671	A (1)
2	Final Settlement											(3,143)	A (1)
3	Non-energy revenue		16,077	1,929	95	1,889	30	464	15,590	1,213	56	37,343	A (3)
4	Flow-through revenue		167,078	55,834	9,720	69,049	2,475	2,937	106,576	36,830	699	451,199	A (2)
5	Sub-total	Sch 1	219,315	75,174	12,032	138,942	3,328	3,615	180,540	62,438	830	693,070	
	Revenue offsets and other adjustments:												
6	Late Payment Charges		1,004	344	55	636	15	17	793	274	4	3,142	
7	Collection & NSF Fees		170	21	2	19	0	5	169	14	1	401	
8	Connection Fees		492	62	6	54	1	14	662	55	3	1,350	
9	Green Power		12	2	0	1	0	0	12	1	0	29	
10	Total revenue offsets and other adjustment	Sch 1	1,679	429	64	710	17	36	1,637	344	7	4,922	A
11	**Total**	Sch 11										**697,993**	

Notes:

Note 1 Included in the energy revenue is the Energy and non-energy return margin totaling $16,901,407 or a pre-tax return rate of $3.438/MWh ($2.51/MWh after tax) in effect January to

Note 2 Included in the Flow-through revenue are LAF, A-1 Rider, and MFF revenue totaling $31,766,942.

Line No.	Line Item Definitions:
1	Energy revenues: revenue associated with the energy charges billed.
2	Final settlement is revenues billed to customers in the current year for prior year consumption.
3	Non-energy revenue: revenue associated with administration charges or customer charges (billed at a fixed amount per day or month).
4	Flow-through revenue: revenue associated with the total distribution tariff, transmission tariff, franchise fee, and local access fee charges billed to customers, on behalf of the distribution utility.
6	Late Payment Charges: revenue associated with the collection of late fees charged to accounts when customers do not pay their bill on time.
7	Collection fees is where EEA delivers a "Turn-Off Notice" to a customer due to non-payment. NSF fees are charged where a customer's payment is not honoured by the customer's bank or financial institution
8	Connection fees related to charges applied for an expedited connection or a reconnection of service after cut-off for non-payment.

EPCOR Energy Alberta GP Inc.
SITES AND ENERGY SALES BY CUSTOMER CLASS
FOR THE YEAR ENDED DECEMBER 31, 2017

Line No.	Description	2017 Fortis Residential	Fortis Farm	Fortis Irrigation	Fortis Small Comm	Fortis Oil Gas	Fortis Lighting	EDTI Residential	EDTI Small Comm	EDTI Lighting	RRT Total
1	Sites - average	242,778	29,867	3,133	26,379	421	6,984	243,273	19,822	926	573,582
2	Energy sales (MWh)	1,820,130	423,079	88,107	639,131	15,296	5,832	1,359,029	562,751	2,192	4,915,549
3	Energy sales per site (kWh/site)	7,497	14,165	28,125	24,229	36,375	835	5,586	28,390	2,367	8,570

Line No.	Description	2016 Fortis Residential	Fortis Farm	Fortis Irrigation	Fortis Small Comm	Fortis Oil Gas	Fortis Lighting	EDTI Residential	EDTI Small Comm	EDTI Lighting	RRT Total
1	Sites - average	246,080	30,849	3,112	27,135	633	7,183	244,123	20,108	965	580,189
2	Energy sales (MWh)	1,829,197	410,770	59,057	648,688	19,928	6,550	1,366,794	575,052	2,355	4,918,390
3	Energy sales per site (kWh/site)	7,433	13,315	18,976	23,906	31,482	912	5,599	28,598	2,439	8,477

Line No. Line Item Definitions:

1 Sites - average: number of sites based on monthly average for the calendar year. A "site" is generally defined as being the finest or lowest level of consumption or usage data. A "site" generally represents a meter installation.

2 Energy sales (MWh): total energy billed and accrued for the applicable customer class.

3 Energy sales per site (kWh/site): line 2 multiplied by 1,000 and divided by line 1.

SCHEDULE 4

EPCOR Energy Alberta GP Inc.
ENERGY AND OPERATING EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 2017
($000s)

Line No.	Description	Cross- Ref. from	2017	2016	Variance higher/(lower)	Variance %	Variance W/P Ref
	Physical spot market						
1	AESO - energy charges		117,031	95,871	21,160	22.1%	
2	AESO - retail adjustment to market (RAM)		(49)	(57)	8	-13.6%	
3	AESO - trading charges		1,665	1,598	67	4.2%	
4	AESO - uplift charges		19	13	6	41.9%	
5	AESO - other		1	1	(0)	-28.6%	
6	NGX Trading		385	450	(66)	-14.6%	
7	Net Hedging		28,546	73,779	(45,233)	-61.3%	
8	Total Energy Expenses		**147,596**	**171,655**	**(24,059)**	**-14.0%**	A (4)
	Other operating expenses (Note)						
9	Credit costs	Sch 10	1,704	2,039	(335)	-16.4%	B
10	Billing & customer care [1]		25,070	25,682	(612)	-2.4%	B
11	Corporate allocations	Sch 10	5,026	5,384	(358)	-6.6%	B
12	Operational and administration costs		2,429	2,495	(66)	-2.6%	B
13	Bad debt expense [2]		3,242	3,876	(634)	-16.3%	B
14	AUC administration fee [3]	Sch 9		-	-	-	
15	Hearing costs [3]	Sch 9	215	(108)	324	-298.7%	B
16	EPSP Costs	Sch 9		-	-	-	
17	Other						
18	Total energy and operating expense		**185,283**	**211,022**	**(25,739)**	**-12.2%**	(to Sch 1)

Notes:

The expenses reported above should exclude regulatory disallowances, as defined on Schedule 11. Any disallowed expenses should be reported on Schedule 11, column H.

Note 1 2016 figures were restated to correct the Long-Term Disability accrual adjustment.

Note 2 Bad debt expense as presented includes accounting adjustments for recognized bad debt expense.

Note 3 In order to make the expenses realized for lines 14 through 16 above agree to the "Recovery through rates" in Schedule 9 column "G" rows 1 through 3, the required amounts reported in lines 14 through 16 above were reclassified from line 12, "Operational and administration costs".

Line No. Line Item Definitions:

1 AESO - energy charges: the cost of energy (electricity) based on hourly consumption and hourly pool prices as calculated by the AESO and identified on the AESO pool statement.

2 AESO - retail adjustment to market (RAM): charges related to a post final adjustment mechanism (PFAM) made in the settlement of load, for the collection/payment required to offset the RSA (retailer specific adjustment) as identified on the AESO pool statement.

3 AESO - trading charges: total trading charges applicable to power pool transactions.

4 AESO - uplift charges: total annual uplift charges as calculated by the AESO and identified on the AESO pool statement.

5 AESO - other: includes all charges on the AESO pool statement not included in any other line item above.

6 NGX - trading charges/auction fees: any charges or fees associated with electricity contracts traded on the NGX.

7 Net hedging cost (revenue): includes costs or revenues associated with financial contracts (e.g. financial swaps) facilitated by an exchange or broker.

9 Credit costs: costs associated with collateral requirements (parental guarantee, letter of credit) trading exchanges or counterparties.

10 Billing & customer care: costs related to billing, call centre and other customer support functions.

11 Corporate allocations: allocated corporate overhead based on AUC approved methodologies.

12 Operational and administration costs: expenses associated with the management of the RRT, including salaries, consultant fees, and travel expenses.

13 Bad debts expense: the amount of non-collectible accounts receivable associated with RRT billings.

14 AUC administration fee: a fee sufficient to pay for the Commission's estimated net expenditures associated with carrying out its powers, duties and functions as assessed by the AUC under Rule 025.

15 Hearing costs: costs associated with proceedings for RRT applications that are approved by the Commission.

16 EPSP costs: expenses related to work conducted by an independent advisor and consultation parties associated with electricity energy price setting plans.

17 Other: includes all expenses not accounted for in line items above. Please identify.

EPCOR Energy Alberta GP Inc.
DEBT CAPITAL EMPLOYED AND INTEREST EXPENSE
FOR THE YEAR ENDED DECEMBER 31
($000s)

2017

Line No.	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Net Underwriting Discount/(Premium) & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Interest Expense
	Long term- debt										
1	Intercompany Debt (IC-EUI-75-00:		8/28/2014	8/28/2024	4.67%	20,000		20,000	0.00%	20,000	933
2	Total long-term debt					20,000	-	20,000	0.00%	20,000	933
3	Total short-term debt								0.00%		(242)
4								Less: interest related to non-regulatory			(251)
5								Less: regulatory interest cost disallowance			175
6								**Total interest expense**			**616** (to Sch 1, Note 1)

Note 1 - RRT Regulatory Interest expense presented consists of cost of debt of $249 thousand and working capital of $367 thousand.

2016

Line No.	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Net Underwriting Discount/(Premium) & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Interest Expense
	Long term- debt										
1	Intercompany Debt (IC-EUI-75-00:		8/28/2014	8/28/2024	4.67%	20,000		20,000	0.00%	20,000	933
2	Total long-term Debt					20,000	-	20,000	0.00%	20,000	933
3	Total short-term Debt								0.00%		(101)
4								Less: interest related to non-regulatory			(293)
5								Less: regulatory interest cost disallowance			107
6								**Total interest expense**			**646** (to Sch 1, Note 2)

SCHEDULE 6

EPCOR Energy Alberta GP Inc.
INCOME TAX/PAYMENT IN LIEU OF TAXES (PILOT)
FOR THE YEAR ENDED DECEMBER 31
($000s)

Line No.	Description	Cross-Ref. from	2017	2016	Variance higher/(lower)	Variance %	Variance W/P Ref
1	Income for RRT (before taxes) [1]		19,351	32,945	(13,594)	-41.3%	B
2	Permanent differences [2]		(19,351)	(32,945)	13,594	-41.3%	B
3	Timing differences		-	-	-	-	B
4	Taxable Income		-	-	-	-	
5	Combined tax rate		27.00%	27.00%			
6	Current tax provision or PILOT (flow-through method)		-	-	-	-	B
7	Adjustments to current tax provision		-	-	-	-	B
8	Future income tax provision (if applicable)		-	-	-	-	B
9	**Total Income Tax Provision**	Sch 11	**-**	**-**	**-**	**-**	(to Sch 1)

	2017	2016
Tax rates:		
Federal	15.0%	15.0%
Provincial	12.0%	12.0%
Combined	27.0%	27.0%

Notes:

Note 1 2016 figures were restated to correct the Long-Term Disability accrual adjustment.

Note 2 EEA LP is not taxable after the February 2014 reorganization to EEA LP.

Line No.	Line Item Definitions:
1	Income for RRT (before taxes): the Regulated Rate Tariff income before tax deductions.
2	Permanent differences: amounts recorded in revenue and expenses that are neither taxable nor deductible in accordance with income tax legislation.
3	Timing differences: amounts recorded in revenue and expense for accounting purposes in a period that does not coincide with the taxation year in which the related amounts are allowed in computing net income for income tax purposes (example, depreciation and amortization included for accounting purposes and capital cost allowance allowed for income tax purposes).
4	Taxable income: the amount of income for RRT adjusted for permanent and timing differences, used in the calculation to determine the current tax payable (line 6).
5	Combined tax rate: combined federal and provincial tax rate in accordance with applicable tax legislation.
6	Current tax provision or PILOT: the income taxes that the utility would pay to the provincial or federal governments if the entity is considered to be a taxable Canadian corporation, or, if the entity is owned by a municipality, it is the amount to be paid to the Balancing Pool under the Payment In Lieu Of Taxes regulation AR 112/2003 and is equal to the amounts determined in accordance with federal and Alberta income tax legislation.
7	Adjustments to current tax provision: can include prior or current year (over)/under provisions or any other adjustments. Provide a detailed explanation of any adjustments reported.
8	Future income tax provision (if applicable): provide a detailed explanation of amount reported.
9	Total income tax provision: the amount shown in line item 6 on schedule 1, as the total income tax expense recognized for regulatory purposes as approved by the AUC.

EPCOR Energy Alberta GP Inc.
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31
($000s)

CAPITAL ASSETS

Line No.	Property Group	Balance at 12/31/2016	2017 Additions	2017 Retirements	2017 Transfers	2017 Adjustments	Balance at 12/31/2017
1	Hardware	-	-	-	-	-	-
2	Leasehold Improvements	308	30	-	-	-	337
3	Telephone System	1,410	279	(11)	-	-	1,679
4	Office Furniture and Equipment	507	451	(8)	-	-	950
5	Computer Equipment	1,331	1,087	(592)	-	-	1,826
6	Software	25,946	5,701	(10,801)	-	-	20,846
7	Customer Rights	51,229	-	-	-	-	51,229
8	**Subtotal**	80,730	7,548	(11,411)	-	-	76,867
9	Capital Work In Progress (CWIP)	3,566	3,981	-	(7,548)	-	0
10	**Total Utility**	**84,296**	**11,529**	**(11,411)**	**(7,548)**	**-**	**76,867**

ACCUMULATED DEPRECIATION

Line No.	Property Group	Balance at 12/31/2016	Depreciation Expense	2017 Retirements	2017 Net Salvage	2017 Adjustments	Balance at 12/31/2017
11	Hardware	-	-	-			-
12	Leasehold Improvements	57	17	-			75
13	Telephone System	937	214	(11)			1,140
14	Office Furniture and Equipment	214	75	(8)			281
15	Computer Equipment	916	401	(592)			725
16	Software	17,143	2,370	(10,801)			8,713
17	Customer Rights	40,988	2,564	-			43,552
18	**Total**	**60,254**	**5,641**	**(11,411)**	**-**	**-**	**54,485**

19	Unreconciled difference	-	
20	Depreciation / amortization adjustment for non-RRT	1,249	
21	Disallowed Depreciation	(184)	
22	Total depreciation and amortization expense	**4,576**	(to Sch 1)

Line No.	Line Item Definitions:
1-8	Asset classifications are not universally defined for RRT providers. Each provider is to include additional asset classification line items to those shown above as deemed necessary.
9	Capital Work In Progress / Assets Under Construction: the balance of expenditures recorded for capital projects that are still in progress at year end.
11-18	Accumulated depreciation reported by asset classifications as reported under capital assets. Depreciation expense also appears on Schedules 1 and 11.
19-21	This line is to account for any necessary adjustments to reconcile line 22 to line 7 on schedule 1. If adjustments are made, an explanation should be provided as to the nature of the adjustments.
22	The total depreciation & amortization amount is the result of the total on line 18, with recognized losses on disposal of assets on retirements, less any adjustment entered on lines 20 and 21. The breakdown is as follows:

Depreciation Expense for 2017 (Line 18)	5,641
Add: Loss recognized on retired assets (Line 10 less Line 18)	-
Less: Adjustment for non-RRT (Line 20)	(1,249)
Less: Disallowed Depreciation (Line 21)	184
Total depreciation and amortization expense - RRT	**4,576**

EPCOR Energy Alberta GP Inc.
MANPOWER SUMMARY
FOR THE YEAR ENDED DECEMBER 31

COST OF MANPOWER

Line No.	Description	2017	2016	Variance higher/(lower)	Variance %	Variance W/P Ref
1	Salaries and wages	20,498	20,106	393	2.0%	
2	Employee benefits	6,010	5,824	186	3.2%	
3	Contracted labour			-		
4	Gross manpower expenses	26,508	25,929	579	2.2%	
5	Less: Capitalized manpower	36	19	17	88.5%	
6	Less: Other reductions in manpower (specify)					
7	**Net manpower operating expense**	**26,472**	**25,910**	**562**	**2.2%**	B

FULL TIME EQUIVALENTS (FTEs)

Line No.	Description	2017	2016	Variance higher/(lower)	Variance %	
8	Regular employees - gross	262.5	265.8	(3.3)	-1.2%	
9	Temporary employees - gross			-		
10	Contract staff - gross			-		
11	Gross FTEs	262.5	265.8	(3.3)	-1.2%	
12	Less: Capitalized manpower	0.2	0.2	(0.0)	-3.5%	
13	Less: Other reductions in manpower (specify)	-	-	-		
14	**Net operating FTEs**	**262.3**	**265.6**	(3.3)	-1.2%	B

Note: The values provided in this schedule for salaries, wages, benefits and FTEs are at the gross level as EEA GP does not have employees dedicated specifically to the provision of services to just the RRT customers. Rather, these costs are pooled and allocated to the RRT customers based on a cost-causation analysis.

Line No.	Line Item Definitions:
1	Salaries and wages: the total amount of salaries and wages (full time, temporary and casual employment) charged to the provider that support the gross full time equivalents presented in line 8. This value does not include the cost of salaries and wages embedded in corporate cost allocated to the provider.
2	Employee benefits: the total amount of employee benefits in addition to the total salaries and wages in line 1.
3	Contracted labour: the total amount of contracted labour. Where contractor charges include both materials and labour, only the labour component of the charges shall be included in this line.
5	Capitalized manpower: the total amount of salaries, wages, benefits and contracted labour charges in lines 1, 2 and 3 that were capitalized.
6	Other reductions in manpower: reductions to the gross manpower expenses not accounted for under capitalized manpower (line 5).
8	Regular employees - gross: the number of full time equivalent (FTE) positions related to the salaries and wages of regular (permanent) employees (either full or part-time) in line 1 above.
	FTE values presented are based on initial analysis and may be subject to classification changes for presentation in future non-energy applications.
9	Temporary employees - gross: the number of FTE positions related to the salaries and wages of temporary employees in line 1 above.
10	Contract staff - gross: the number of FTE positions related to the contracted labour expense in line 3 above.
12	Capitalized manpower: the number of FTE positions related to the total amount of salaries, wages, benefits and contracted labour charges capitalized in line 5.
13	Other reductions in manpower: reductions to the gross FTEs not accounted for under capitalized manpower (line 12).

EPCOR Energy Alberta GP Inc.
RESERVE ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31
($000s)

Line No.	Description	Balance at 12/31/2016 (Note 1)	Costs incurred	Recovery through Rates (Note 2)	Balance at 12/31/2017 (Note 1)	
1	AUC Administration Fee	-	-	-	-	(to Sch 4)
2	Energy Price Setting Plan (Note 3)	-	-	-	-	(to Sch 4)
3	Hearing Costs	(64)	216	(215)	(64)	(to Sch 4)
4	**Total**	**(64)**	**216**	**(215)**	**(64)**	

Notes:

Note 1 Positive balance indicates a receivable; negative balance indicates a liability

Note 2 The corresponding expense on Schedule 4 lines 15 and 16

Note 3 EPSP Costs were previously included on Schedule 9, however the Energy Price Setting Plan does not have reserve accounts, therefore EEA determined that this was not applicable and has removed the EPSP costs from this schedule.

Line No.	Line Item Definitions:
1	AUC administration fee: a fee sufficient to pay for the Commission's estimated net expenditures associated with carrying out its powers, duties and functions as assessed by the AUC under Rule 025.
2	Energy Price Setting Plan refers to costs associated with proceedings for the EPSP that are approved by the Commission Providers are to add line items for any additional reserve accounts approved by the AUC.
3	Hearing costs: costs associated with proceedings for RRT applications that are approved by the Commission. Providers are to add line items for any additional reserve accounts approved by the AUC.

EPCOR Energy Alberta GP Inc.
AFFILIATE TRANSACTIONS
FOR THE YEAR ENDED DECEMBER 31
($000s)

Line No.	Affiliate Name	Nature of Service	2017 Net	2017 Revenue	2017 Expense	2016 Net	Variance higher/(lower)	Variance %		Variance W/P Ref
1	EUI	Administration Allocations	5,026		5,026	5,384	(358)	-6.6%	(to Sch 4)	D
2		Rent & Security	1,727		1,727	1,814	(88)	-4.8%		
3		Information Technology	1,021		1,021	1,129	(109)	-9.6%		D
4		Interest on Debt	616		616	647	(31)	-4.7%	(to Sch 5)	
5		Credit Costs	1,704		1,704	2,039	(335)	-16.4%	(to Sch 4)	D
6		Salary and benefit related costs	17,371		17,371	17,275	96	0.6%		
7	EWSI	Energy Sales	-			-	-	0.0%		
8	ETECH	Energy Sales	-			-	-	0.0%		
9	EDTI	Energy Sales	(38)	38		(25)	(13)	52.7%		
10		Tariff Charges	161,181		161,181	144,148	17,033	11.8%		D
13		Shared Services	238		238	278	(40)	-14.5%		
							-			
17	**Total**		**188,846**	**38**	**188,884**	**172,690**				

Line No. 1-17 Line Item Definitions:

Services with affiliates are not universally defined. Providers are to add line items for any additional transactions with an affiliate.

Column definitions:

2017 Net: sum of 2017 revenue and 2017 expense columns.

2017 Revenue: affiliate transactions that are recorded as a revenue to the RRT provider.

2017 Expense: affiliate transactions that are recorded as an expense to the RRT provider.

2016 Net: sum of prior year affiliate transactions (may be a credit or debit).

SCHEDULE 11

EPCOR Energy Alberta GP Inc.

RECONCILIATION FROM AUDITED INCOME STATEMENT TO REGULATORY SCHEDULES

FOR THE YEAR ENDED DECEMBER 31, 2017

($000s)

Line No.	Description	2017 Audited Income Statement	Non RRT Related Adjustments	Regulatory Cost Disallowanc	RRT Portion	
1	**Revenue**	780,249			780,249	
2	Adjustment for revenue not associated with RRT operations		(83,855)		(83,855)	
3	Total	780,249	(83,855)		696,394	(to Sch 2)
4	**Expenses**					
5	Energy and operating expenses	185,881		(599)	185,283	(to Sch 4)
6	Flow through expenses	486,330			486,330	(to Sch 1)
7	Adjustment for expenses not associated with RRT or disallowed	73,187	(73,187)		-	
8	Total	745,399	(73,187)	(599)	671,612	
9	**Depreciation and Amortization**	5,641			5,641	
10	Adjustment for expenses not associated with the RRT or disallowed		(1,249)	184	(1,065)	
11	Total	5,641	(1,249)	184	4,576	(to Sch 7)
12	**Interest Expense**	691			691	
13	Adjustment for expenses not associated with the RRT or disallowed		(251)	175	(75)	
14	Total	691	(251)	175	616	(to Sch 5)
15	**Income/(Loss) before tax**	28,518	(9,167)	239	19,590	(to Sch 6)
16	**Income Tax**					
17	Adjustment for expenses not associated with the RRT or disallowed					
18	Total	-	-	-	-	(to Sch 6)
19	**Net Income/(Loss)**	**28,518**	**(9,167)**	**239**	**19,590**	(to Sch 1)

Providers are to add line items for any additional adjusting entries if not listed here.

Note: A regulatory cost disallowance is a cost incurred by a regulated rate tariff provider in the course of business, but the Commission specifically disallowed the inclusion of the cost in a rate setting decision or an AUC rule.

Rule 005
December 31, 2017
Working Paper A: Energy, Non-Energy, Flow-through Revenues and Expenses and Interest Expense
2017 to 2016 Year-Over-Year Variance Analysis
($000s)

Load and sites provided for information purposes as variance on these items is not significant.

Average Sites		
2016	580,189	from Sch 3 Line 1
2017	573,582	from Sch 3 Line 1
	(6,607)	

Load (GWh)		
2016	4,918	from Sch 3 Line 2
2017	4,916	from Sch 3 Line 2
	(2)	

Variance Explanation: The site count and load consumption in 2017 varied slightly from 2016 levels. The variance was immaterial.

Total Energy & Flow-through Revenues as Follows:	2016	2017	Variance	Ref
Energy & Final Settlement	204,528	161,660	(42,868)	(1)
Flow-through	451,199	493,374	42,175	(2)
Non-Energy	37,343	37,246	(97)	(3)
Non-Energy 2014-16 True-Up		(201)	(201)	
Total	693,070	692,079	(991)	

(1) Energy Revenues & Final Settlements		$/MWh
2016 Energy Revenues	204,528	41.59
2017 Energy Revenues	161,660	32.89
Variance	(42,868)	

Variance Explanation: The decrease in Energy revenues is primarily due to a decrease in prices. The Non-Energy 2014-16 True-up billed in 2017 reflects one quarter of the $0.805 million to be refunded to customers pursuant to Decision 22414-D01-2017. Due to an error the remaining $0.603 million will be refunded in April 2018 pursuant to Decision 23309-D01-2018.

(2) Flow-through Revenues		$/MWh
2016 Flow-through Revenues	451,199	91.75
2017 Flow-through Revenues	493,374	100.37
Variance	42,175	

Variance Explanation: The increase in Flow-through revenues is due to an increase in distribution and transmission costs per MWh.

(3) Non-Energy Revenues

2016 Actual	37,343	from Sch 2 Line 3
2015 Non-Energy true-up billed in 2016	-	
2016 adjusted	37,343	
2017 Actual	37,045	from Sch 2 Line 3
2014-16 Non-Energy true-up billed in 2017	201	
2017 adjusted	37,246	
Variance	(97)	

Variance Explanation: Decrease in non-energy revenue is due to a decrease in sites compared to the prior year. The Non-Energy 2014-16 True-up billed in 2017 reflects one quarter of the $0.805 million to be refunded to customers pursuant to Decision 22414-D01-2017. Due to an error the remaining $0.603 million will be refunded in April 2018 pursuant to Decision 23309-D01-2018.

Revenue Offsets & Other Adjustments

2016 Revenue Offsets & other Adjustments	4,922	from Sch 1 Line 2
2017 Revenue Offsets & other Adjustments	4,315	from Sch 1 Line 2
Variance	(607)	

Variance Explanation: Decrease in revenue offsets is primarily due to an E-Bill credit introduced in 2017 and decreased late payment charges which are driven by lower revenues.

Total Energy & Flow-through expenses as Follows:	**2016**	**2017**	**Variance**	**Ref**
Energy	171,655	147,596	(24,059)	(4)
Flow-through	447,581	486,330	38,749	(5)
Total	619,236	633,926	14,690	

(4) Energy Expenses & Final Settlements

2016 Energy Expenses	171,655	from Sch 4 Line 8
2017 Energy Expenses	147,596	from Sch 4 Line 8
Variance	(24,059)	

Variance Explanation: Energy expenses have decreased by $24.1M due to lower hedging costs of $45.2M, partially offset by higher AESO charges of $21.2M due to higher pool prices. The decrease in net hedging costs is due to the difference between contract prices and pool prices.

(5) Flow-through Expenses

2016 Flow-through Expenses	447,581	from Sch 1 Line 8
2017 Flow-through Expenses	486,330	from Sch 1 Line 8
Variance	38,749	

Variance Explanation: The increase in Flow-through expenses is due to an increase in distribution and transmission costs per MWh. Flow-through expense variances correspond with flow-through revenue variances.

(6) Interaffiliate Flow-through Expenses

2016 Interaffiliate Flow-through Expenses	144,148	from Sch 10 Line 10
2017 Interaffiliate Flow-through Expenses	161,181	from Sch 10 Line 10
Variance	17,033	

Variance Explanation: The increase in Interaffiliate Flow-through expenses is due to an increase in distribution and transmission costs per MWh.

Rule 005
December 31, 2017
Working Paper B: Operating Expenses, Depreciation & Income Tax
2017 to 2016 Year-Over-Year Variance Analysis
($000s)

Credit Costs

2016	2,039	from Sch 4 Line 9
2017	1,704	from Sch 4 Line 9
Variance	(335)	

Variance Explanation: The decrease in credit costs is primarily due to a decrease in NGX credit cost and no more EPSP backstop credit costs after April 2017. This is partially offset by an increase in AESO related credit costs in 2017.

Interaffiliate Credit Costs

2016	2,039	from Sch 10 Line 5
2017	1,704	from Sch 10 Line 5
Variance	(335)	

Variance Explanation: All EEA credit costs are interaffiliate and thus the explanation is the same as above.

Billing & Customer Care

2016	25,682	from Sch 4 Line 10
2017	25,070	from Sch 4 Line 10
Variance	(612)	

Variances Explained

LTD Cash vs Accrual Adjustment	(677)	from Appendix C Line 24
Other Variances	65	
Total variance explained	(612)	

Variance Explanation: Year over year billing and customer care costs are primarily decreased due to a larger LTD Cash vs Accrual adjustment for 2017 as a result of the 2017 adjustment being a credit compared to an expense in 2016. The remaining is offset by numerous smaller variances.

Total RRT & Non-RRT Manpower Operating Expense

2016	25,910	from Sch 8 Line 7
2017	26,472	from Sch 8 Line 7
Variance	562	

Total RRT & Non-RRT Manpower FTEs

2016	265.6	from Sch 8 Line 14
2017	262.3	from Sch 8 Line 14
Variance	(3.3)	

Variance Explanation: Overall payroll costs are increased due to higher salaries offset by a decreased full time equivalent requirement.

Corporate Allocations

2016	5,384	from Sch 4 Line 11
2017	5,026	from Sch 4 Line 11

Variance	(358)	

Variance Explanation: Decreased corporate allocations in 2017 due primarily to lower costs being allocated as a result of the Drainage transfer from the City of Edmonton in 2017, which are offset by lower disallowed corporate allocation costs.

Bad Debt Expense

2016	3,876	from Sch 4 Line 13
2017	3,242	from Sch 4 Line 13
Variance	(634)	

Variance Explanation: Decrease in bad debt expense primarily driven by a decrease in energy revenues due to a decrease in price.

Hearing Costs

2016	(108)	
2017	215	from Sch 4 Line 15
Variance	323	

Variance Explanation: Hearing costs have increased as 2017 includes recoveries for hearing costs in the 2016-17 RRT application while 2016 includes a refund of hearing cost deferral amount.

Income for RRT (before taxes)

2016	32,945	from Sch 6 Line 1	
2015 Non-Energy true-up billed in 2016	-		
2016 adjusted	**32,945**		
2017	19,351	from Sch 6 Line 1	
2014 - 2017 Non-Energy true-up billed in 2017	201		
2017 adjusted	**19,552**		
Variance	(13,393)		13,594

Variances Explained

Energy Margin - related to mark to market entries for contracts for differences	(4,964)
Energy Margin - related to lower risk compensation	(9,651)
Energy Margin - related to energy return margin	717
Energy Margin - related to prior year resettlement	(647)
Energy Margin - related to lower other EPSP rates	(837)
Lower Non-Energy Revenues primarily due to decreased rates	(97)
Higher Hearing Costs recovered through rates	(323)
Lower Bad Debt Expense due to lower experience	634
Lower Allocated Corporate Costs	358
Lower Billing and Customer Care costs	612
Lower Credit Costs	335
Lower Depreciation Expense	256
Other	216
Total Variances Explained	(13,393)

Variance Explanation - Energy Margin: Effective July 1, 2011, EEA GP has operated under the Energy Price Setting Plan which resulted in procuring the Energy for its RRT customers through NGX auctions. The contracts entered into during these auctions are contracts for differences. As a result, EEA GP is required to fair value these contracts at each period end date. If we remove the fair value adjustments in each year, the comparable gross margins would be \$19.13M and \$29.55M. The adjusted 2017 gross margin is \$10.42M lower than the 2016 margin due to lower return margin rates. This explanation is summarized in the table below.

Energy Margin Comparison
($ millions)

	2017	2016	Variance
Gross Margin	21.11	36.49	(15.38) [1]
Add back costs recorded for future consumption periods	(0.37)	1.60	1.97
Bring in costs recorded in prior periods for current consumption	(1.60)	(8.54)	(6.94)
Adjusted Gross Margin	19.13	29.55	(10.42)

[1] - *No longer includes hearing cost expenses for Gross Margin presentation.*

Permanent Differences on Income Tax

2016	(32,945)	from Sch 6 Line 2
2017	(19,351)	from Sch 6 Line 2
Variance	13,594	

Variance Explanation: EEA LP is not taxable. Differences above are due to a decrease in EEA LP's Net Income related to RRT.

Depreciation

2016	4,832	From Sch 7 Line 22
2017	4,576	From Sch 7 Line 22
Variance	(256)	

Variance Explanation: Decrease in depreciation expense is primarily due to depreciation on assets reaching their end of their useful lives, as well as a lower percentage of costs being allocated to the RRT compared to 2016.

Rule 005
December 31, 2017
Working Paper C: Regulatory Cost Disallowances
2017 to 2016 Year-Over-Year Variance Analysis
($000s)

Regulatory Cost Disallowances		
2016	1,117	
2017	239	From Sch 11 Line 19
	(878)	

Regulatory Cost Disallowance Detail:	**2017**	**2016**	**Var**	**Ref**
Non-Recoverable Corporate Allocations				
Public & Government Affairs	285	340	(55)	(1)
Short-term Incentive	-	31	(31)	not material
Mid-term Incentive	78	126	(48)	not material
Shared Services	83	100	(18)	not material
Corporate Rent	53	79	(26)	(2)
Total Disallowed Corporate Allocations	499	677	(177)	
Non-Recoverable Direct Rent Expense	226	238	(12)	(2)
Non-Recoverable EEA GP STIP	25	68	(43)	not material
Non-Recoverable LTIP/MTIP	36	58	(22)	not material
Non-Recoverable Long-term Disability [1]	(280)	398	(677)	(3)
Non-Recoverable Depreciation	(184)	(242)	58	(4)
Non-Recoverable HCRA / EPSP	93	29	64	(5)
Non-Recoverable Interest Expense	(175)	(107)	(68)	(6)
Total	**239**	**1,117**	**(878)**	

Note 1 2016 figures restated to correct the Long-Term Disability accrual adjustment.

Variance Explanations:

(1) Lower year over year Public & Government affairs allocations to be disallowed due to a lower percentage of costs being allocated to the RRT compared to 2016.

(2) Lower year over year Rent disallowances due to a lower percentage of costs being allocated to the RRT compared to 2016.

(3) Larger difference in Long-term disability provisions in 2017 as compared to 2016 as a result of the 2017 adjustment being a credit compared to an expense in 2016.

(4) Higher Non-Recoverable Depreciation difference due to a lower percentage of costs being allocated to the RRT compared to 2016.

(5) Increased non-recoverable hearing costs were spent during 2017 as compared to 2016.

(6) Difference due to higher short term interest during 2017 as compared to 2016, resulting in a lower non-recoverable expense.

Rule 005
December 31, 2017
Working Paper D: Interaffiliate Transactions
2017 to 2016 Year-Over-Year Variance Analysis
($000s)

Administrative Allocations

2016	5,384	From Sch 10 Line 1
2017	5,026	From Sch 10 Line 1
	(358)	

Variance Explanation: Decreased corporate allocations in 2017 due primarily to lower costs being allocated as a result of the Drainage transfer from the City of Edmonton in 2017, which are offset by lower disallowed corporate allocation costs.

Information Technology

2016	1,129	From Sch 10 Line 3
2017	1,021	From Sch 10 Line 3
	(109)	

Variance Explanation: Affiliate information technology expenses lower during 2017 as compared to 2016 due to lower interdepartmental charges primarily related to lower hardware and software licence fees.

Interaffiliate Credit Costs

2016	2,039	from Sch 10 Line 5
2017	1,704	from Sch 10 Line 5
Variance	(335)	

Variance Explanation: The decrease in credit costs is primarily due to a decrease in NGX credit cost and no more EPSP backstop credit costs after April 2017. This is partially offset by an increase in AESO related credit costs in 2017.

Tariff Charges

2016	144,148	From Sch 10 Line 10
2017	161,181	From Sch 10 Line 10
	17,033	

Variance Explanation: The increase in Interaffiliate Flow-through expenses is due to an increase in distribution and transmission costs per MWh.

Financial Statements of

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Years ended December 31, 2017 and 2016

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Financial Statements

Years ended December 31, 2017 and 2016

KPMG LLP
2200, 10175 101 St NW
Edmonton AB T5J 0H3
Telephone (780) 429-7300
Fax (780) 429-7379
www.kpmg.ca

INDEPENDENT AUDITORS' REPORT

To the General Partner of EPCOR Energy Alberta Limited Partnership

We have audited the accompanying financial statements of EPCOR Energy Alberta Limited Partnership, which comprise the statements of financial position as at December 31, 2017 and December 31, 2016, the statements of comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the 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 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.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of EPCOR Energy Alberta Limited Partnership as at December 31, 2017 and December 31, 2016, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants
February 15, 2018
Edmonton, Canada

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Statements of Comprehensive Income
(In thousands of Canadian dollars)

Years ended December 31, 2017 and 2016

	2017	2016
Revenues and other income:		
Electricity sales	$ 747,897	$ 749,375
Other income (note 5)	32,352	29,597
	780,249	778,972
Operating expenses:		
Electricity purchases and system access fees	681,908	666,581
Other raw materials and operating charges	199	444
Staff costs and employee benefits expenses	27,075	27,884
Depreciation and amortization (note 6)	5,641	5,968
Other administrative expenses	34,044	34,678
	748,867	735,555
Operating income	31,382	43,417
Finance expenses (note 7)	(2,864)	(3,299)
Comprehensive income for the year - all attributable to the Partners	$ 28,518	$ 40,118

The accompanying notes are an integral part of these financial statements

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Statements of Financial Position
(In thousands of Canadian dollars)

December 31, 2017 and 2016

	2017	2016
ASSETS		
Current assets:		
Cash (note 8)	$ 3,668	$ 1,532
Trade and other receivables (note 9)	130,160	116,857
Derivatives (note 10)	958	-
	134,786	118,389
Non-current assets:		
Property, plant and equipment (note 11)	2,284	1,876
Intangible assets (note 12)	20,098	22,166
	22,382	24,042
TOTAL ASSETS	$ 157,168	$ 142,431
LIABILITIES AND EQUITY		
Current liabilities:		
Trade and other payables (note 13)	$ 98,437	$ 86,062
Loans and borrowings (note 14)	9,531	6,202
Provisions (note 15)	1,023	1,083
Customer deposits	13,601	13,736
Derivatives (note 10)	-	293
	122,592	107,376
Non-current liabilities:		
Loans and borrowings (note 14)	20,000	20,000
Provisions (note 15)	1,870	2,348
	21,870	22,348
Total liabilities	144,462	129,724
Equity attributable to the Partners:		
Partnership units (note 16)	12,706	12,707
Total equity	12,706	12,707
TOTAL LIABILITIES AND EQUITY	$ 157,168	$ 142,431

Approved on behalf of the EPCOR Board,

Hugh J. Bolton
Director, EPCOR Utilities Inc.

Vito Culmone
Director, EPCOR Utilities Inc.

The accompanying notes are an integral part of these financial statements

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Statements of Changes in Equity
(In thousands of Canadian dollars)

December 31, 2017 and 2016

	Partnership units (note 16)	Retained earnings (deficit)	Equity attributable to the Partners
Equity at December 31, 2015	$ 40,894	$ (28,187)	$ 12,707
Comprehensive income for the year	-	40,118	40,118
Distribution to partners	-	(11,931)	(11,931)
Return of partnership capital	(28,187)	-	(28,187)
Equity at December 31, 2016	12,707	-	12,707
Comprehensive income for the year	-	28,518	28,518
Distribution to partners	(1)	(28,518)	(28,519)
Equity at December 31, 2017	$ 12,706	$ -	$ 12,706

The accompanying notes are an integral part of these financial statements

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Statements of Cash Flow
(In thousands of Canadian dollars)

Years ended December 31, 2017 and 2016

	2017	2016
Cash flows from (used in) operating activities:		
Comprehensive income for the year	$ 28,518	$ 40,118
Reconciliation of comprehensive income for the year to cash from (used in) operating activities:		
Depreciation and amortization (note 6)	5,641	5,968
Interest paid	(3,052)	(3,018)
Finance expenses (note 7)	3,052	3,018
Changes in employee benefits provisions (note 15)	(538)	102
Changes in customer deposits	(135)	(1,582)
Fair value change on derivative instruments (note 10)	(1,251)	(1,363)
Funds from operations	32,235	43,243
Changes in non-cash operating working capital (note 17)	23	14,740
Net cash flows from operating activities	32,258	57,983
Cash flows from (used in) investing activities:		
Acquisition of property, plant and equipment[1]	(998)	(989)
Acquisition of intangible assets[1]	(2,983)	(3,088)
Changes in non-cash investing working capital (note 17)	(951)	1,111
Net cash used in investing activities	(4,932)	(2,966)
Cash flows from (used in) financing activities:		
Net proceeds from issuance (repayment) of short-term loans and borrowings[2] (note 14)	3,329	(16,289)
Distribution to partners	(28,518)	(11,931)
Return of partnership capital	(1)	(28,187)
Net cash flows used in financing activities	(25,190)	(56,407)
Increase (decrease) in cash	2,136	(1,390)
Cash, beginning of year	1,532	2,922
Cash, end of year	$ 3,668	$ 1,532

1 Interest payment of $188 (2016 – $63) is included in acquisition of property, plant and equipment and intangible assets.
2 Changes in short-term loans and borrowings arose from financing cash flows.

The accompanying notes are an integral part of these financial statements

1. Description of business

(a) Nature of operations

EPCOR Energy Alberta Limited Partnership (the Partnership or EEALP) provides electricity service through its general partner EPCOR Energy Alberta GP Inc. (the General Partner or EEAGP) to regulated rate option (RRO) eligible and default supply customers within the EPCOR Distribution & Transmission Inc. (EDTI) and FortisAlberta Inc. service areas. EEALP provides contact centre and billing and collection services to other EPCOR subsidiaries for water, wastewater, sanitary and stormwater, gas and electricity services. Contact centre and billing and collection services are also provided to The City of Edmonton (the City) Waste Management Department and Capital Power Corporation and its subsidiaries.

The Partnership operates in Canada with its registered head office located at 2000, 10423 – 101 Street, NW, Edmonton, Alberta, Canada, T5H 0E8.

EEALP is a limited partnership registered in Canada. The Partnership has one limited partner, EPCOR Power Development Corporation (EPDC), and is managed by EEAGP. Although the General Partner holds legal title to the assets, the Partnership is the beneficial owner and assumes all the risks and rewards of the assets.

The Partnership is indirectly 100% owned by EPCOR Utilities Inc. (EPCOR).

(b) Rate regulation

The Partnership's operations are regulated by the Alberta Utilities Commission (AUC), pursuant to the *Electric Utilities Act* (Alberta). The AUC administers this act and related regulations regarding tariffs, rates, and service area. The Partnership operates under cost-of-service regulation whereby the AUC issues rate orders establishing the revenue requirement of the business which is the revenue required to recover approved operating costs and to provide a reasonable return. The Partnership applies for non-energy rates based on approved revenue requirement. Once the rates are approved, they are not adjusted as a result of actual costs of service being different from those which were estimated. The Partnership is required to file rate applications with the AUC, for the approval of regulated rate tariff (RRT) electricity billing rates and RRT non-energy revenue billing rates. After a process of public consultation is completed, the AUC approves the rates for the specified period.

In March 2015, the AUC issued a decision that approved an Energy Price Setting Plan (EPSP) for the period August 1, 2016 to June 30, 2018, which determines the electricity margin, procurement method and electricity rates for the Partnership's RRT customers. As part of this decision the AUC approved a combined energy and non-energy return margin structure for the Partnership. Prior to this decision, the Partnership earned separate energy and non-energy return margins through its energy and non-energy rates. The combined energy and non-energy return margin structure took effect in 2 stages. In August 2015, the Partnership's energy return margin increased to the higher level approved in the March 2015 decision and in March 2016 the Partnership began collecting the full combined energy and non-energy margin through its energy rates (1.50% of total RRO revenues, including energy revenues, non-energy revenues and revenues on flow-through distribution and transmission charges). The approved combined energy and non-energy return margin for the Partnership was $3.44/MWh in 2017 (2016 – the energy return margin was $2.73/MWh and non-energy return margin for the Partnership was 6.00% of the approved RRO revenue requirement from January 1, 2016 to February 29, 2016, and the approved combined energy and non-energy return margin was $3.44/MWh from March 1, 2016 to December 31, 2016).

2. Basis of presentation

(a) Statement of compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). These financial statements were approved and authorized for issue by the EPCOR Board of Directors on February 15, 2018.

(b) Basis of measurement

The Partnership's financial statements are prepared on the historical cost basis, except for its derivative financial instruments which are measured at fair value.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars and all rounded to the nearest thousand dollars, except where otherwise stated.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to all years presented in these financial statements unless otherwise indicated.

(a) Changes in significant accounting policies

The Partnership adopted amendments to various accounting standards effective from January 1, 2017, that did not have a significant impact on these financial statements.

(b) Revenue recognition

Revenue is recognized to the extent that it is probable that economic benefits will flow to the Partnership for the provision of goods or services and where the revenue can be reliably measured. Revenues are measured at the fair value of the consideration received or to be received, excluding sales tax. Revenues from sales of electricity are recognized upon delivery. These revenues include an estimate of the value of goods and services consumed by customers and billed subsequent to the reporting period.

(c) Income taxes

As a limited partnership, EEALP is not taxed at the entity level under the Canadian Income Tax Act. All tax consequences of its operations are borne by its partners on a pro rata basis in proportion to their interest in the Partnership.

(d) Property, plant and equipment

Property, plant and equipment (PP&E) are recorded at cost, net of accumulated depreciation and accumulated impairment losses, if any.

Cost includes contracted services, materials, direct labor, directly attributable overhead costs, and borrowing costs on qualifying assets. Where parts of an item of PP&E have different estimated economic useful lives, they are accounted for as separate items (major components) of PP&E.

The cost of major inspections and maintenance is recognized in the carrying amount of the item if the asset recognition criteria are satisfied. The carrying amount of a replaced part is derecognized. The costs of day-to-day servicing are expensed as incurred.

Depreciation of cost less residual value is charged on a straight-line basis over the estimated economic useful lives of items of each depreciable component of PP&E, from the date they are available for use, as this most closely reflects the expected usage of the assets. Work in progress is not depreciated. Estimating the appropriate economic useful lives of assets requires significant judgment and is generally based on estimates of life characteristics of similar assets. The estimated economic useful lives, methods of depreciation and residual values are reviewed annually with any changes adopted on a prospective basis.

The range of estimated economic useful lives for retail systems and equipment is 4 to 10 years.

Gains and losses on the disposal of PP&E are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are included within depreciation and amortization.

(e) Intangible assets

Intangible assets with finite lives are stated at cost, net of accumulated amortization and impairment losses, if any.

Customer rights represent the costs to acquire the rights to provide electricity services to customers in the

FortisAlberta Inc. service territory for a finite period of time. Customer rights are recorded at cost at the date of acquisition. A subsequent expenditure is capitalized only when it increases the future economic benefit in the specific asset to which it relates.

The cost of intangible software includes the cost of license acquisitions, contracted services, materials, direct labor, along with directly attributable overhead costs and borrowing costs on qualifying assets.

Amortization of the cost of finite life intangible assets is recognized on a straight-line basis over the estimated economic useful lives of the assets, from the date they are available for use, as this most closely reflects the expected usage of the asset. Work in progress is not amortized. The estimated economic useful lives and methods of amortization are reviewed annually, with any changes adopted on a prospective basis.

The estimated economic useful lives for intangibles with finite lives are as follows:

Customer rights	20 years
Software	5 - 20 years

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are included within depreciation and amortization.

(f) Provisions

A provision is recognized if, as a result of a past event, the Partnership has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a financing expense over the estimated time period until settlement of the obligation.

(g) Derivative financial instruments

The Partnership uses contracts-for-differences to reduce its exposure to movements in electricity prices. These instruments are used to establish a fixed price for electricity procured primarily to supply RRT customers.

The Partnership sells electricity to customers under a RRT. As part of the RRT, the amount of electricity to be economically hedged, the hedging method and the electricity selling prices to be charged to these customers is determined by an EPSP. Under the EPSP, the Partnership manages its exposure to fluctuating wholesale electricity spot prices by entering into financial electricity purchase contracts up to 120 days in advance of the month of consumption in order to economically hedge the price of electricity under a well-defined risk management process set out in the EPSP. Under these instruments, the Partnership agrees to exchange, with a single creditworthy and adequately secured counterparty, the difference between the Alberta Electric System Operator (AESO) market price and the fixed contract price for a specified volume of electricity for the forward months, all in accordance with the EPSP. The Partnership may enter into additional financial electricity purchase contracts outside the EPSP to further economically hedge the price of electricity.

All derivative financial instruments are recorded at fair value as derivative assets or derivative liabilities on the statement of financial position, to the extent they have not been settled, with all changes in the fair value of derivatives recorded in comprehensive income. At initial recognition, attributable transaction costs are recognized in comprehensive income.

The fair value of derivative financial instruments reflects changes in the electricity prices. Fair value is determined based on exchange price quotations in active markets. Fair value amounts reflect management's best estimates using external readily observable market data, such as forward electricity prices. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

(h) Non-derivative financial instruments

Financial assets are identified and classified as one of the following: measured at fair value through profit or loss or loans and receivables. Financial assets are measured at fair value through profit or loss if classified as held for trading or designated as such upon initial recognition. Financial liabilities are classified as measured at fair value through profit or loss or as other financial liabilities.

Financial assets and financial liabilities are presented on a net basis when the Partnership has a legally enforceable right to set off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

Financial instruments held at fair value through profit or loss

The Partnership may designate financial instruments as measured at fair value through profit or loss when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis.

Upon initial recognition, directly attributable transaction costs are recognized in comprehensive income as incurred. Changes in fair value of financial instruments measured at fair value through profit or loss are recognized in comprehensive income.

Loans and receivables

Cash and trade and other receivables are classified as loans and receivables.

The Partnership’s loans and receivables are recognized initially at fair value plus directly attributable transaction costs, if any. After initial recognition, they are measured at amortized cost using the effective interest method less any impairment as described in note 3(i). The effective interest method calculates the amortized cost of a financial asset or liability and allocates the finance income or expense over the term of the financial asset or liability using an effective interest rate. The effective interest rate is the rate that exactly discounts estimated future cash payments or receipts through the expected life of the financial instrument, or a shorter period when appropriate, to the net carrying amount of the financial asset or financial liability.

Other financial liabilities

The Partnership’s trade and other payables, customer deposits and loans and borrowings are classified as other financial liabilities and recognized on the date at which the Partnership becomes a party to the contractual arrangement. Other financial liabilities are derecognized when the contractual obligations are discharged, cancelled or expire.

Other financial liabilities are initially recognized at fair value, plus directly attributable transaction costs, if any. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method.

(i) Impairment of financial assets

The Partnership's financial assets held as loans and receivables are assessed for indicators of impairment at each reporting date. An impairment loss for financial assets is recorded when it is identified that there is objective evidence that one or more events has occurred, after the initial recognition of the asset, that has had a negative impact on the estimated future cash flows of the asset and that can be reliably estimated. Trade and other receivables that are not assessed for impairment individually are assessed for impairment on a collective basis. Objective evidence of impairment includes the Partnership’s past experience of collecting payments as well as observable changes in national or local economic conditions.

For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the asset's original effective interest rate. If, in a subsequent year, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed or adjusted within comprehensive income. An impairment loss is reversed only to the extent that the financial asset's carrying amount does not exceed the carrying amount that would have been determined if no impairment loss had been recognized.

(j) Impairment of non-financial assets

The carrying amounts of the Partnership's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. Non-financial assets include PP&E and intangible assets.

The recoverable amount of an asset is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.

An impairment loss is recognized if the carrying amount of an asset exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a fundamental change, since the date of impairment, which may improve the financial performance of the non-financial asset. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(k) Standards and Interpretations not yet applied

A number of new standards, amendments to standards and interpretations have been issued by the IASB and the International Financial Reporting Interpretations Committee the application of which is effective for periods beginning on or after January 1, 2018. Those which may be relevant and may impact on the accounting policies of the Partnership are set out below. The Partnership does not plan to adopt these standards early.

IFRS 9 - *Financial Instruments* (IFRS 9), which replaces IAS 39 - *Financial Instruments: Recognition and Measurement*, includes a new classification and measurement approach for financial assets that reflects the business model in which they are held and the characteristics of their contractual cash flows. IFRS 9 contains three principal classification categories for financial assets including (i) measured at amortized cost, (ii) fair value through other comprehensive income and (iii) fair value through profit or loss. IFRS 9 also replaces the "incurred loss" model under IAS 39 with a forward looking "expected credit loss" (ECL) model for recognition of impairment on financial instruments.

Based on the assessment of the Partnership's existing financial instruments, the Partnership does not expect any material impact on the accounting for its financial instruments as a result of the adoption of IFRS 9. The Partnership expects to record an adjustment to the provision of allowance of doubtful accounts on its trade receivables resulting from the application of the methodology of the calculation prescribed by the new standard. As per the Partnership's existing policy, the allowance for doubtful accounts is calculated on the overdue balances of trade receivables only, whereas the new impairment model requires the Partnership to calculate the lifetime ECL on the initial recognition of trade receivables, instead of on the overdue balances only. Accordingly, the Partnership will be required to recognize the lifetime ECL on all outstanding trade receivables. As the Partnership has very short credit periods for trade receivables, the Partnership does not expect any material impact due to implementation of the new requirements in IFRS 9.

IFRS 15 - *Revenue from Contracts with Customers* (IFRS 15), which replaces IAS 11 - *Construction Contracts* and IAS 18 - *Revenue* and related interpretations, introduces a new single revenue recognition model for contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized.

There are two methods by which the new standard can be adopted: (1) a full retrospective approach with a restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment recognized in retained earnings as of the date of adoption. The Partnership will adopt IFRS 15 using the modified retrospective approach with the cumulative effect of the adjustment, if any, recognized as of January 1, 2018, subject to allowable and elected practical expedients.

The Partnership has performed detailed analysis on each revenue stream and the underlying contracts with customers to determine the impact of IFRS 15 on the financial statements. A significant portion of the Partnership's revenue is generated from electricity sales. The Partnership will continue to recognize electricity sales revenue over time as the Partnership's customers simultaneously receive and consume the electricity as it is provided. The Partnership currently recognizes gross revenue from sales of electricity, which include collection of third party distribution and transmission charges. All related distribution and transmission costs are recognized as operating expenses under energy purchases and system access fees. The Partnership is finalizing its position regarding whether the third party distribution and transmission charges to customers will constitute consideration received for fulfillment of a performance obligation or are a flow-through charge.

As a result of the adoption of the new standard, the Partnership will be required to include significant disclosures in the financial statements based on the prescribed requirements. These new disclosures will include information regarding the significant judgments used in evaluating how and when revenues are recognized and information related to contract assets and deferred revenues. In addition, IFRS 15 requires that the Partnership's revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing, and estimates of revenues and cash flows generated from contracts with customers. The Partnership is in the process of preparing its draft disclosures, which will be required for the December 31, 2018 financial statements.

For all other contracts with customers, the Partnership does not expect the implementation of IFRS 15 to have material changes in the timing or amounts of revenues recognized.

4. Use of estimates

The preparation of the Partnership's financial statements in accordance with IFRS requires management to make estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the financial statements.

The Partnership reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgment in making these estimates and assumptions. Adjustments to previous estimates, which may be material, are recorded in the period in which they become known. Actual results may differ from these estimates.

Assumptions and uncertainties that have a significant risk of resulting in a material adjustment within the next financial year include:

Revenues

Significant accounting estimates were made in determining revenue recognized for unbilled customer consumption. By regulation, wire service providers in Alberta have four months to submit the final electricity load settlement data after the month in which such electricity was consumed. The data and associated processes and systems used by the Partnership to estimate electricity revenues and costs, including unbilled consumption, are complex. The Partnership's estimation procedures will not necessarily detect errors in underlying data provided by industry participants including wire service providers and load settlement agents.

Fair value measurement

For accounting measures such as determining asset impairments and recording derivative assets and liabilities the Partnership is required to estimate the fair values of those assets and liabilities. Estimates of fair value may be based on readily determinable market values or depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

(In thousands of Canadian dollars unless otherwise indicated)

5. Other income

	2017	2016
Commercial services	$ 26,801	$ 23,855
Late payment charges and interest income	3,403	3,530
Collection fees	704	687
Connection fees	1,444	1,525
	$ 32,352	$ 29,597

6. Depreciation and amortization

	2017	2016
Depreciation of property, plant and equipment	$ 590	$ 487
Amortization of intangible assets	5,051	5,481
	$ 5,641	$ 5,968

7. Finance expenses

	2017	2016
Interest on loans and borrowings, net of interest income	$ (1,117)	$ (1,175)
Guarantee and letters of credit fees	(1,935)	(2,187)
Capitalized interest	188	63
	$ (2,864)	$ (3,299)

8. Cash

Under certain agreements between the Partnership and the Natural Gas Exchange (NGX) for the purchase of electricity derivative financial contracts, the Partnership established separate bank accounts through which the settlement of the electricity derivative financial contracts are processed in conjunction with letters of credit and cash as collateral. As security for the payment and performance of its obligations, the Partnership assigned a first ranking security interest on the balances of these accounts to NGX. The Partnership's use of this cash is restricted to these purposes. At December 31, 2017, $3,668 (2016 – $1,532) was held in these bank accounts.

9. Trade and other receivables

	2017	2016
Trade receivables	$ 73,360	$ 59,325
Accrued revenues	58,133	58,911
Gross accounts receivables	131,493	118,236
Allowance for doubtful accounts	(1,882)	(1,928)
Net accounts receivables	129,611	116,308
Prepaid expenses	549	549
	$ 130,160	$ 116,857

Details of the aging of accounts receivables and analysis of the changes in the allowance for doubtful accounts are provided in note 20.

10. Derivatives

Derivative financial instruments are contracts-for-differences held for the purpose of electricity price management.

(In thousands of Canadian dollars unless otherwise indicated)

The derivative financial instruments used for risk management purposes as described in note 20 consist of the following:

	2017	2016
Electricity price forward contracts		
Fair value	$ 370	$ (1,605)
Cash paid to counterparty	588	1,312
Net fair value	$ 958	$ (293)
Net notional buys		
Gigawatt hours of electricity	1,076	1,098
Range of contract terms (in years)	0.1 - 0.3	0.1 - 0.3

The fair value of electricity derivative financial instruments reflects changes in the forward electricity prices, net of cash payments to or from the counterparty. During the course of the contracts, daily payments are made to or received from the counterparty to settle the fair value of the contracts.

Fair value is determined based on quoted exchange index prices by reference to bid or asking price, as appropriate, in active markets. Fair value amounts reflect management's best estimates using external readily observable market data such as forward electricity prices. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

The change in fair value of $1,975 (2016 – $6,939) on unsettled electricity derivative financial instruments is recorded in electricity purchases and system access fees in the statements of comprehensive income.

11. Property, plant and equipment

	Work in progress	Retail systems & equipment	Total
Cost			
Balance, beginning of 2017	$ 849	$ 2,363	$ 3,212
Additions	998	-	998
Disposals and retirements	-	(611)	(611)
Transfers into service	(1,847)	1,847	-
Balance, end of 2017	-	3,599	3,599
Accumulated depreciation			
Balance, beginning of 2017	-	1,336	1,336
Depreciation	-	590	590
Disposals and retirements	-	(611)	(611)
Balance, end of 2017	-	1,315	1,315
Net book value, end of 2017	$ -	$ 2,284	$ 2,284

(In thousands of Canadian dollars unless otherwise indicated)

	Work in progress	Retail systems & equipment	Total
Cost			
Balance, beginning of 2016	$ -	$ 3,081	$ 3,081
Additions	849	140	989
Disposals and retirements	-	(858)	(858)
Balance, end of 2016	849	2,363	3,212
Accumulated depreciation			
Balance, beginning of 2016	-	1,707	1,707
Depreciation	-	487	487
Disposals and retirements	-	(858)	(858)
Balance, end of 2016	-	1,336	1,336
Net book value, end of 2016	$ 849	$ 1,027	$ 1,876

12. Intangible assets

	Work in progress	Customer rights	Software	Total
Cost				
Balance, beginning of 2017	$ 2,718	$ 51,228	$ 27,139	$ 81,085
Additions	2,983	-	-	2,983
Disposals and retirements	-	-	(10,801)	(10,801)
Transfers into service	(5,701)	-	5,701	-
Balance, end of 2017	-	51,228	22,039	73,267
Accumulated amortization				
Balance, beginning of 2017	-	40,987	17,932	58,919
Amortization	-	2,564	2,487	5,051
Disposals and retirements	-	-	(10,801)	(10,801)
Balance, end of 2017	-	43,551	9,618	53,169
Net book value, end of 2017	$ -	$ 7,677	$ 12,421	$ 20,098

(In thousands of Canadian dollars unless otherwise indicated)

	Work in progress	Customer rights	Software	Total
Cost				
Balance, beginning of 2016	$ -	$ 51,228	$ 30,655	$ 81,883
Additions	2,718	-	370	3,088
Disposals and retirements	-	-	(3,886)	(3,886)
Balance, end of 2016	2,718	51,228	27,139	81,085
Accumulated amortization				
Balance, beginning of 2016	-	38,424	18,900	57,324
Amortization	-	2,563	2,918	5,481
Disposals and retirements	-	-	(3,886)	(3,886)
Balance, end of 2016	-	40,987	17,932	58,919
Net book value, end of 2016	$ 2,718	$ 10,241	$ 9,207	$ 22,166

Included in customer rights are the Partnership's customer rights to operate in the FortisAlberta service territory which will expire on December 31, 2020.

13. Trade and other payables

	2017	2016
Trade payables	$ 17,902	$ 5,168
Accrued liabilities	80,535	80,894
	$ 98,437	$ 86,062

14. Loans and borrowings

	2017	2016
Short-term note payable to EPCOR	$ 9,531	$ 6,202
Long-term notes payable to EPCOR		
At 4.67%, due in 2024	20,000	20,000
Total loans and borrowings	29,531	26,202
Less: current portion	9,531	6,202
	$ 20,000	$ 20,000

The short-term notes payable to EPCOR are unsecured and due on demand.

The long-term notes payable to EPCOR are unsecured. Interest on notes is payable semi-annually while principal is due at the end of the term.

15. Provisions

	2017	2016
Employee benefits	$ 2,893	$ 3,431
Less: current portion	1,023	1,083
	$ 1,870	$ 2,348

Employee benefits consist mainly of obligations for benefits provided to employees on long-term disability leaves and employee incentive plans.

(In thousands of Canadian dollars unless otherwise indicated)

16. Partnership Units

The Partnership is authorized to issue unlimited number of Class A Common units without nominal or par value. The units are voting and participate equally in profits, losses and capital distributions of the Partnership.

The General Partner holds one (2016 – one) Class A common unit having capital contribution of $1.00 (2016 – $1.00) in the Partnership. It manages the operations of the Partnership and has a 0.01% (2016 – 0.01%) interest in the profits, losses and capital distributions of the Partnership.

The Limited partner holds 129,500,999 (2016 – 129,500,999) Class A common units representing a net capital contribution of $12,706 (2016 – $12,707) in the Partnership. The Limited Partner has 99.99% (2016 – 99.99%) interest in the profits, losses and capital distribution of the Partnership.

17. Change in non-cash working capital

	2017	2016
Trade and other receivables (note 9)	$ (13,303)	$ 17,188
Trade and other payables (note 13)	12,375	(1,337)
	$ (928)	$ 15,851
Operating activities	$ 23	$ 14,740
Investing activities	(951)	1,111
	$ (928)	$ 15,851

18. Related party balances and transactions

The Partnership is indirectly 100% owned by EPCOR, which is in turn 100% owned by the City. The Partnership provides electricity, billing, customer care and collection services pursuant to service agreements with EPCOR and its subsidiaries and the City. EPCOR and its subsidiaries provide services which include administration, maintenance, repairs, utilities, facilities, general plant use, employee costs, executive oversight, legal, finance, treasury, audit, and safety oversight, human resources and information technology services to the Partnership pursuant to the service agreements. Transactions between the Partnership and its related parties are in the normal course of operations and are generally based on normal commercial rates or as agreed to by the parties.

The following summarizes the Partnership's related party transactions with EPCOR and its subsidiaries:

	2017	2016
Statements of Comprehensive Income		
Revenues and other income (a)	$ 20,082	$ 16,067
Electricity purchases and system access fees (b)	180,219	159,187
Staff costs and employee benefits expenses (c)	27,075	27,884
Other administrative expenses (d)	14,311	14,706
Finance expenses (e)	2,626	3,018

(a) Comprised of commercial services revenue for the provision of customer billing services of $19,929 (2016 – $15,925) and electricity sales of $153 (2016 – $142).

(b) Comprised of distribution and transmission purchases.

(c) Relates to staff costs and employee benefits expenses paid by EPCOR.

(d) Comprised of administrative services provided by EPCOR and its subsidiaries.

(e) Comprised of fees for providing letters of credit and parental guarantees on behalf of EEALP of $1,935 (2016 – $2,187), and interest on loans and borrowings of $691 (2016 – $831).

(In thousands of Canadian dollars unless otherwise indicated)

The following summarizes the Partnership's related party balances with EPCOR and its subsidiaries:

	2017	2016
Statements of Financial Position		
Trade and other receivables (f)	$ 3,317	$ 503
Property, plant and equipment and intangible assets (g)	3,739	3,481
Trade and other payables (h)	20,742	16,833
Loans and borrowings (note 14)	29,531	26,202
Provisions (note 15)	2,893	3,431

(f) Comprised of cash settlement balances of $1,833 (2016 – nil) and receivables for the provision of customer services of $1,484 (2016 – $503).

(g) Relates to expenditures for information services projects.

(h) Comprised of balances payable for distribution and transmission services of $18,266 (2016 – $13,599), cash settlement of $1,443 (2016 – $1,340), administration services of $565 (2016 – $465), and interest on loans and borrowings of $319 (2016 – $319) and capital accrual of $149 (2016 – 1,111).

The following summarizes the Partnership's related party transactions with the City:

	2017	2016
Statements of Comprehensive Income		
Revenues and other income (i)	$ 6,676	$ 7,661
Other administrative expenses (j)	1,009	1,012

(i) Comprised of commercial services revenue for the provision of customer services of $6,603 (2016 – $7,535), electricity sales of $59 (2016 – $102) and interest income of $14 (2016 – $24).

(j) Comprised of cash processing fees of $1,008 (2016 - $1,011) and business taxes of $1 (2016 - $1).

The following summarizes the Partnership's related party balances with the City:

	2017	2016
Statements of Financial Position		
Trade and other receivables (k)	401	-
Trade and other payables (l)	170	3,709

(k) Represents balance receivable for cash settlement.

(l) Represents balances payable for cash processing fees and cash settlement.

(In thousands of Canadian dollars unless otherwise indicated)

19. Financial instruments

Classification

The classification of the Partnership's financial instruments at December 31, 2017 and 2016, is summarized as follows:

	Classification			
	Fair value through profit or loss	Loans and receivables	Other financial Liabilities	Fair value hierarchy
Measured at fair value				
Derivatives – designated (note 10)	X			Level 1
Measured at amortized cost				
Cash (note 8)		X		Level 1
Trade and other receivables (note 9)		X		Level 3
Trade and other payables (note 13)			X	Level 3
Loans and borrowings (note 14)			X	Level 2
Customer deposits			X	Level 3

Fair value

The carrying amounts of all financial instruments approximate their fair values due to their short-term nature except for loans and borrowings.

	2017		2016	
	Carrying amount	Fair value	Carrying amount	Fair value
Loans and borrowings	$ 29,531	$ 31,173	$ 26,202	$ 28,907

Fair value hierarchy

The financial instruments of the Partnership that are recorded at fair value have been classified into levels using a fair value hierarchy. A Level 1 valuation is determined by unadjusted quoted prices in active markets for identical assets or liabilities. A Level 2 valuation is based upon inputs other than quoted prices included in Level 1 that are observable for the instruments either directly or indirectly. A Level 3 valuation for the assets and liabilities is not based on observable market data.

Derivatives

Fair value is determined based on exchange index prices in active markets. Fair value amounts reflect management's best estimates using external readily observable market data such as forward electricity prices. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Loans and borrowings

Short-term loans and borrowings are measured at amortized cost and their carrying value approximate their fair value due to the short-term nature of these financial instruments.

The fair value of the Partnership's non-current loans and borrowings is based on determining a current yield for the Partnership's debt at December 31, 2017 and 2016. This yield is based on an estimated credit spread for the Partnership over the yields of long-term Government of Canada bonds for Canadian dollar loans that have similar maturities to the Partnership's debt. The estimated credit spread is based on the Partnership's indicative spread as published by independent financial institutions.

20. Financial risk management

Overview

The Partnership is exposed to a number of different financial risks arising from business activities and its use of financial instruments, including market risk, credit risk, and liquidity risk. The Partnership's overall risk management process is designed to identify, assess, measure, manage, mitigate and report on business risk which includes financial risk. Enterprise risk management is overseen by EPCOR's Board of Directors and senior management is responsible for fulfilling objectives, targets, and policies approved by the Board of Directors of EPCOR. EPCOR's Director, Audit and Risk Management provides the Board of Directors of EPCOR with an enterprise risk assessment quarterly. Risk management strategies, policies and limits are designed to help ensure the risk exposures are managed within EPCOR's business objectives and risk tolerance. The Partnership's financial risk management objective is to protect and minimize volatility in earnings and cash flow.

Financial risk management including interest rate risk, liquidity risk and the associated credit risk management is carried out by the centralized Treasury function in accordance with applicable policies. The Audit Committee of the Board of Directors of EPCOR, in its oversight role, performs regular and ad-hoc reviews of risk management controls and procedures to help ensure compliance.

Market risk

Market risk is the risk of loss that results from changes in market factors such as electricity prices and interest rates. The level of market risk to which the Partnership is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements, and the composition of the Partnership's financial assets and liabilities held. EPCOR's financial exposure management policy is approved by the Board of Directors of EPCOR and the associated procedures and policies are designed to manage the electricity prices and interest rate risk throughout the group including the Partnership.

To manage the exposure related to changes in market risk related to electricity prices, the Partnership uses contracts-for-differences as a risk management technique. These instruments are used to establish a fixed price for electricity purchases.

The sensitivities provided in the following risk discussions disclose the effect of reasonable changes in relevant prices and rates on comprehensive income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these contracts. The Partnership's actual exposure to market risk is constantly changing as the Partnership's portfolio of commodity contracts changes. Changes in fair values or cash flows based on market variable fluctuations cannot be extrapolated since the relationship between the change in the market variable and the change in fair value or cash flows may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Partnership.

Electricity price and volume risk

The Partnership sells electricity to RRO customers under a RRT. All electricity for the RRO customers is purchased in real time from the AESO in the spot market. Under the RRT, the amount of electricity to be economically hedged, the hedging method and the electricity selling prices to be charged to these customers is determined by the EPSP. Under the EPSP, the Partnership uses financial contracts to economically hedge the RRO requirements and incorporate the price into customer rates for the applicable month. Fixed volumes of electricity are economically hedged using financial contracts-for-differences up to 120 days in advance of the month in which the electricity (load) is consumed by the RRO customers. The volume of electricity economically hedged in advance is based on load (usage) forecasts for the consumption month. When consumption varies from forecast consumption patterns, the Partnership is exposed to prevailing market prices when the volume of electricity economically hedged is short of actual load requirements or greater than the actual load requirements (long). Exposure to variances in electricity volume can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.

Under contracts-for-differences the Partnership agrees to exchange, with a single creditworthy and adequately secured counterparty, the difference between the AESO electricity spot market price and the fixed contract price for a specified volume of electricity up to 120 days in advance of the consumption date, all in accordance with the EPSP. The contracts-for-differences are referenced to the AESO electricity spot price and any movement in the AESO price results in changes in the contract settlement amount. If the risks of the EPSP were to become untenable, the Partnership could test the market and potentially re-contract the procurement risk under an outsourcing arrangement at a certain cost that would likely increase procurement costs and reduce margins. The Partnership may enter into additional financial electricity purchase contracts outside the EPSP to further economically hedge the price of electricity.

At December 31, 2017, holding all other variables constant, a $5 per megawatt hour increase / decrease in the forward electricity price would increase / decrease comprehensive income by approximately $5,381 (2016 - $5,492). In preparing the sensitivity analysis, the Partnership compared average AESO electricity spot prices to the forward index price for the past 24 months. Based on historical fluctuations, the Partnership estimates that the fair value of the contracts could increase or decrease by up to $5,796 (2016 - $22,254) with a corresponding change to comprehensive income.

Interest rate risk

The Partnership is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. At December 31, 2017 and 2016, all long-term debt was fixed rate.

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. EPCOR's counterparty credit risk management policy is approved by the EPCOR Board of Directors and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the group including the Partnership. Credit and counterparty risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into a transaction with the counterparty. Exposures and concentrations are subsequently monitored and are regularly reported to senior management. In its role as the default electricity provider for its service territories, the Partnership must provide service to customers who choose to receive regulated electricity service. Amounts owing from customers are monitored and are regularly reported to senior management. Creditworthiness continues to be evaluated after transactions have been initiated, at a minimum, on an annual basis. To manage and mitigate credit risk, the Partnership employs various credit mitigation practices such as pre-payment arrangements from retail customers and other forms of credit enhancement including cash deposits, parent company guarantees and bank letters of credit.

Maximum credit risk exposure

The Partnership's maximum credit exposure is represented by the carrying amount of the trade and other receivables balance of $129,611 (2016 – $116,308). These carrying amounts do not take into account collateral held. At December 31, 2017, the Partnership held cash deposits of $13,601 (2016 – $13,736) as security for certain counterparty accounts receivable.

Credit quality and concentrations

The Partnership is exposed to credit risk on outstanding trade receivables associated with its electricity sales to retail customers. The credit quality of the Partnership's trade receivables is unrated. The Partnership is also exposed to credit risk from its derivative assets.

Rate-regulated customer credit risk

Credit risk exposure for residential and commercial customers under default electricity and regulated electricity supply rates is generally limited to amounts due from customers for electricity consumed but not yet paid for. The Partnership mitigates credit risk from counterparties under RRT electricity supply rates by performing credit checks and on higher risk customers, by taking pre-payments or cash deposits. The Partnership monitors credit risk for this portfolio at the gross exposure level.

(In thousands of Canadian dollars unless otherwise indicated)

Trade and other receivables and allowance for doubtful accounts

Trade and other receivables consist primarily of amounts due from retail customers including residential and commercial customers. Commercial customers provide performance assurances through letters of credit, irrevocable guarantees and bonds. For retail customers, represented by a diversified customer base, credit losses are generally low and the Partnership provides for an allowance for doubtful accounts on estimated credit losses.

The aging of accounts receivables was as follows:

December 31, 2017	Gross accounts receivables	Allowance for doubtful accounts	Net accounts receivables
Current[1]	$ 119,722	$ -	$ 119,722
Outstanding 31 to 60 days	7,206	-	7,206
Outstanding 61 to 90 days	2,314	-	2,314
Outstanding more than 90 days	2,251	1,882	369
	$ 131,493	$ 1,882	$ 129,611

December 31, 2016	Gross accounts receivables	Allowance for doubtful accounts	Net accounts receivables
Current[1]	$ 107,853	$ -	$ 107,853
Outstanding 31 to 60 days	5,939	-	5,939
Outstanding 61 to 90 days	2,115	-	2,115
Outstanding more than 90 days	2,329	1,928	401
	$ 118,236	$ 1,928	$ 116,308

1 Current amounts represent trade and other receivables outstanding up to 30 days. Amounts outstanding for more than 30 days are considered past due.

The changes in the allowance for doubtful accounts were as follows:

	2017	2016
Balance, beginning of year	$ 1,928	$ 1,765
Additional allowances created	5,681	5,655
Recovery of receivables	858	1,323
Receivables written off	(6,585)	(6,815)
Balance, end of year	$ 1,882	$ 1,928

Bad debt expense of $5,681 (2016 – $5,655) recognized in the year relates to customer amounts owing that the Partnership determined would not be fully collectable. Allowances for doubtful accounts are determined by considering the unique factors of different customer types. Allowances and write-offs are determined by applying specific risk factors to customer groups' aged balances in trade and other receivables or by reviewing material accounts on a case-by-case basis. Reductions in trade and other receivables and the related allowance for doubtful accounts are recorded when the Partnership has determined that recovery is not possible.

At December 31, 2017, the Partnership held $13,601 (2016 – $13,736) of customer deposits for the purpose of mitigating the credit risk associated with trade and other receivables from residential and commercial customers.

(In thousands of Canadian dollars unless otherwise indicated)

Liquidity risk

Liquidity risk is the risk that the Partnership will not be able to meet its financial obligations as they become due. The Partnership's liquidity is managed centrally by EPCOR's Treasury function. EPCOR manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements of the Partnership are addressed through operating cash flows, and if necessary, intercompany financing from EPCOR.

The Partnership has a private indicative rating of BBB (low), assigned by DBRS Limited.

The undiscounted cash flow requirements and contractual maturities of the Partnership's financial liabilities, including interest payments, are as follows:

At December 31, 2017:

	2018	2019	2020	2021	2022	2023 and thereafter	Total contractual cash flows
Trade and other payables[1]	$ 98,118	$ -	$ -	$ -	$ -	$ -	$ 98,118
Loans and borrowings	9,531	-	-	-	-	20,000	29,531
Interest payments on loans and borrowings	933	933	933	933	933	1,547	6,212
Customer deposits	13,601	-	-	-	-	-	13,601
	$122,183	$ 933	$ 933	$ 933	$ 933	$ 21,547	$ 147,462

At December 31, 2016:

	2017	2018	2019	2020	2021	2022 and thereafter	Total contractual cash flows
Trade and other payables[1]	$ 85,743	$ -	$ -	$ -	$ -	$ -	$ 85,743
Loans and borrowings	6,202	-	-	-	-	20,000	26,202
Interest payments on loans and borrowings	933	933	933	933	933	2,478	7,143
Customer deposits	13,736	-	-	-	-	-	13,736
Derivatives	293	-	-	-	-	-	293
	$106,907	$ 933	$ 933	$ 933	$ 933	$ 22,478	$ 133,117

1 Excluding accrued interest on loans and borrowings of $319 (2016 – $319).

The Partnership's undiscounted cash flow requirements and contractual maturities in the next twelve months of $122,183 (2016 - $106,907) will be funded from operating cash flows.

21. Capital management

The Partnership's primary objectives when managing capital is to safeguard the Partnership's ability to continue as a going concern, pay cash distributions to its unit holders, and to maintain a suitable credit rating. The Partnership manages its capital structure in a manner consistent with the risk characteristics of the underlying assets and in accordance with AUC regulatory decisions. This overall objective and policy for managing capital remained unchanged in the current year from the prior year.

(In thousands of Canadian dollars unless otherwise indicated)

The Partnership manages capital through regular monitoring of cash requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Partnership matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Partnership considers its capital structure to consist of loans and borrowings (including current portion) and unit holder's equity. The following table represents the Partnership's total capital:

	2017	2016
Loans and borrowings (note 14)	$ 29,531	$ 26,202
Total equity	12,706	12,707
Total capital	$ 42,237	$ 38,909

For the years ended December 31, 2017 and 2016, the Partnership complied with all externally imposed capital restrictions.

To manage or adjust its capital structure, the Partnership can issue new debt, repay existing debt or issue or redeem common units.

22. Commitments and contingencies

The following are the Partnership's commitments and contingencies not otherwise disclosed in these financial statements:

(a) Commitments for the purchase of general administrative and operation services from EPCOR and its subsidiaries are estimated at $13,803 (2016 – $14,135). These estimates are subject to change based on actual activity levels.

(b) The Partnership is committed to pay interest and fees to EPCOR for providing letters of credit, parental guarantees and cash collateral on its behalf to EDTI, FortisAlberta Inc., AESO and NGX. The fees charged to EEALP for the letters of credit and parental guarantees are based on the total value outstanding of $78,500 (2016 – $95,300). The letters of credit expire on various dates in 2018. All letters of credit renew automatically.

(c) The Partnership is subject to various legal claims that may arise in the normal course of business. Management believes that the aggregate contingent liability of the Partnership arising from these claims is immaterial and therefore no provision has been made.

23. Comparative information

The comparative information in these financial statements have been reclassified, where applicable, to conform to current year presentation.