ATCO Electric Transmission (AET)
SUMMARY OF REVENUE REQUIREMENT
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Description	Cross-Reference	2018 Actual	2018 Approved*	2017 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Return on Rate Base	Sch 2.0-T	299.8	-	341.5	(41.8)	-12.2%	
2	Fuel		7.5	-	6.9	0.6	8.4%	
3	Operating and Maintenance	Sch 3.0-T	174.2	-	170.4	3.8	2.2%	
4	Depreciation and Amortization	Sch 4.0-T	193.0	-	148.4	44.6	30.1%	
5	Utility Income Tax	Sch 5.0-T	25.1	-	38.1	(13.0)	-34.2%	
6	Subtotal		699.6	-	705.4	(5.9)	-0.8%	
7								
8	Revenue Offsets		(29.3)	-	(32.0)	2.7	-8.4%	
9								
10	**Total Transmission Revenue Requirement**	Sch 10	670.3	-	673.5	(3.2)	-0.5%	
11								
12								
13	<u>Detailed Revenue Requirement</u>							
14	Transmission Tariff Revenue		673.8	-	673.8	-	0.0%	
15	Deferral Account		(3.5)	-	(0.3)	(3.1)	918.4%	**Note 1**
16	**Total Transmission Revenue Requirement**	Line 10	670.3	-	673.5	(3.1)	-0.5%	
17								
18	**Variance Explanations**							

Note 1 2018 Actuals are lower than 2017 Actuals by ($3.1) due to the year-over-year changes in the direct assigned capital deferral ($6.2), deducting deferral ($1.1), and debt rate deferral ($0.1). This variance is partially offset by increases in the year-over-year changes in taxes other than income (property taxes) deferral account ($4.3). Once a decision is received on AET's 2018-2019 GTA, the transmission tariff revenue along with the calculation of actual deferral balances will be finalized. Balances accumulated in the deferral account will be trued up with the AESO in ATCO Electric's 2018 Transmission Deferral Application.

* In accordance with the guidance provided under Section 4.3.3 for AUC Rule 005, whereby interim rates are in place pending a final decision by the AUC, AET has provided a comparison of its 2018 Actuals against its prior year actuals.

ATCO Electric Transmission (AET)
SUMMARY OF RETURN ON RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

2018 Actuals

Line No.	Description	Cross-Reference	Mid-Year Capital	Ratio	Prorated Rate Base	Cost Rate %	Return $	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	**Mid Year Rate Base (Farms, Irrigation Transmission)**				33.4	4.63%	1.5	(0.5)	-23.2%	
2	**Mid Year Rate Base**									
3	Long-Term Debt	Sch 2.2-T	3,289.7	61.29%	3,116.1	4.64%	144.6	(3.6)	-2.4%	
4	Preferred Shares	Sch 2.2-T	91.7	1.71%	86.8	3.96%	3.4	(0.1)	-2.2%	
5	Common Equity	Sch 2.2-T	1,985.7	37.00%	1,880.8	7.99%	150.2	(37.7)	-20.0%	**Note 1**
6	**Mid-Year Net Rate Base**	Sch 1.0-T	5,367.1	100.00%	5,083.7	5.90%	299.8	(41.8)		
7	Contribution for Extensions				522.6					
8	No Cost Capital	Sch 2.1-T			175.2					
9	**Mid Year Rate Base**				5,781.5					

2017 Actuals

Line No.	Description	Cross Reference	Mid Year Capital	Deemed Structure	Prorated Rate Base	Cost Rate %	Return $
10	**Mid Year Rate Base (Farms, Irrigation Transmission)**				33.7	5.98%	2.0
11	**Mid Year Rate Base**						
12	Long-Term Debt	Sch 2.2-T	3,195.1	61.24%	3,121.6	4.75%	148.2
13	Preferred Shares	Sch 2.2-T	91.7	1.76%	89.6	3.93%	3.5
14	Common Equity	Sch 2.2-T	1,930.3	37.00%	1,885.9	9.96%	187.8
15	**Mid-Year Net Rate Base**	Sch 1.0-T	5,217.0	100.00%	5,097.0	6.70%	341.5
16	Contribution for Extensions				517.1		
17	No Cost Capital	Sch 2.1-T			158.5		
18	**Mid Year Rate Base**				5,772.7		
19							
20	**Return Variance**						

Note 1 2018 Return on Common Equity is lower than 2017 Actuals due to 2018 Tariff Revenue being approved, on an interim basis, at the 2017 Approved Tariff Revenue (which included a one-time refund to customers).

ATCO Electric Transmission (AET)
SUMMARY OF MID-YEAR RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Description	Cross-Reference	2018 Actual	2018 Approved*	2017 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
	Gross Utility Plant in Service							
1	Opening Balance	Sch 4.1-T	7,109.9	-	6,977.5	132.4	1.9%	
2	Closing Balance	Sch 4.1-T	7,351.5	-	7,111.4	240.1	3.4%	
3	**Mid-Year Gross Utility Plant in Service**		7,230.7	-	7,044.4	186.3	2.6%	
4								
5	Accumulated Depreciation - Utility							
6	Opening Balance	Sch 4.1-T	1,400.1	-	1,238.7	161.4	13.0%	
7	Closing Balance	Sch 4.1-T	1,583.5	-	1,400.2	183.3	13.1%	
8	**Mid-Year Accumulated Depreciation - Utility**		1,491.8	-	1,319.4	172.4	13.1%	
9								
10	Contributions in Aid of Construction							
11	Opening Balance		540.0	-	527.2	12.8	2.4%	
12	Closing Balance		540.6	-	540.0	0.6	0.1%	
13	**Mid-Year Utility Contributions in Aid of Construction**		540.3	-	533.6	6.7	1.3%	
14								
15	Amortization of Contributions							
16	Opening Balance		54.2	-	44.7	9.4	21.1%	
17	Closing Balance		62.4	-	54.2	8.2	15.2%	
18	**Mid-Year Utility Amortization of Contributions**		58.3	-	49.5	8.8	17.9%	
19								
20								
21	**Mid-Year Net Utility Plant in Service**		5,256.9	-	5,240.8	16.0	0.3%	
22								
23	Necessary Working Capital		42.6	-	47.7	(5.1)	-10.6%	
24								
25	No Cost Capital		(175.2)	-	(158.5)	(16.7)	10.5%	
26								
27	**Mid-Year Net Rate Base**		5,124.3	-	5,130.0	(5.7)	-0.1%	
28								
29	Mid-Year Contributions CWIP		(40.6)	-	(33.0)			
30								
31	**Total Mid-Year Rate Base and CWIP**	Sch. 2.0-T	**5,083.7**	**-**	**5,097.0**			

* In accordance with the guidance provided under Section 4.3.3 for AUC Rule 005, whereby interim rates are in place pending a final decision by the AUC, AET has provided a comparison of its 2018 Actuals against its prior year actuals.

ATCO Electric Transmission (AET)
SUMMARY OF MID-YEAR CAPITAL STRUCTURE
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Description	Cross-Reference	Current Year-End	Previous Year-End	Actual Mid-Year Capital	2017 Actual Mid-Year Capital	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Long-Term Debt	Sch 2.3	3,340.2	3,239.3	3,289.7	3,195.1	94.7	3.0%	
2	Preferred Shares	Sch 2.4	91.7	91.7	91.7	91.7	0.0	0.0%	
3	Common Equity		2,098.4	1,873.0	1,985.7	1,930.3	55.4	2.9%	
4									
5	**Total Mid-Year Invested Capital**		**5,530.2**	**5,204.0**	**5,367.1**	**5,217.0**	**150.1**	**2.9%**	

ATCO Electric Transmission (AET)
SCHEDULE OF DEBT CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

2018 Actual

Line No.	Cross-Reference	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate
1		LT Adv. -Parent											
2			Y	1990-11-30	2020	11.770%	22.4	0.2	22.2	11.81%	22.4	2.6	
3			Z	1991-12-18	2022	9.920%	29.3	0.4	29.0	9.98%	29.3	2.9	
4			AA	1992-12-08	2023	9.400%	13.8	0.1	13.7	9.45%	13.8	1.3	
5			1999	1999-08-01	2019	6.800%	43.2	0.3	42.9	6.83%	43.1	2.9	
6			2004	2004-01-23	2019	5.432%	34.3	0.2	34.1	5.47%	34.3	1.9	
7			2004	2004-11-18	2034	5.896%	71.1	0.4	70.6	5.93%	70.8	4.2	
8			2005	2005-11-30	2035	5.183%	56.3	0.4	56.0	5.22%	56.1	2.9	
9			2006	2006-11-20	2021	4.801%	59.3	0.3	58.9	4.84%	59.2	2.9	
10			2006	2006-11-20	2036	5.032%	59.3	0.4	58.9	5.07%	59.0	3.0	
11			2007	2007-11-01	2037	5.556%	79.2	0.5	78.7	5.60%	78.9	4.4	
12			2008	2008-05-26	2028	5.563%	29.3	0.2	29.1	5.61%	29.2	1.6	
13			2008	2008-05-26	2038	5.580%	44.0	0.3	43.7	5.63%	43.8	2.5	
14			2009	2009-03-06	2024	6.215%	68.1	0.4	67.6	6.27%	67.9	4.3	
15			2009	2009-03-07	2039	6.500%	85.7	0.6	85.1	6.55%	85.3	5.6	
16			2010	2010-11-10	2050	4.947%	73.3	0.5	72.8	4.99%	72.9	3.6	
17			2011	2011-10-24	2041	4.543%	192.8	1.2	191.6	4.58%	191.8	8.8	
18			2011	2011-10-24	2061	4.593%	77.1	0.5	76.6	4.62%	76.6	3.5	
19			2012	2012-09-10	2042	3.805%	317.3	2.0	315.3	3.84%	315.6	12.1	
20			2012	2012-09-10	2062	3.825%	126.8	0.8	126.0	3.85%	126.0	4.9	
21			2012	2012-11-14	2052	3.857%	161.2	1.0	160.2	3.89%	160.2	6.2	
22			2013	2013-09-09	2043	4.722%	241.0	1.6	239.4	4.76%	239.6	11.4	
23			2013	2013-09-18	2063	4.855%	75.0	0.6	74.4	4.90%	74.4	3.6	
24			2013	2013-11-07	2053	4.558%	225.0	1.4	223.6	4.59%	223.7	10.3	
25			2014	2014-09-05	2044	4.085%	555.0	3.5	551.5	4.12%	551.8	22.7	
26			2014	2014-10-17	2054	4.094%	180.0	1.2	178.8	4.13%	178.8	7.4	
27			2015	2015-07-27	2045	3.960%	110.0	0.8	109.2	4.00%	109.3	4.4	
28			2015	2015-10-29	2055	4.211%	185.0	1.3	183.7	4.25%	183.8	7.8	
29			2018	2018-11-21	2048	3.950%	90.0	0.6	89.4	3.98%	89.4	3.6	
30											3,287.2	153.4	4.67%
31													
32		Short-term Debt / (Investment)				2.25%	53.0		53.0	2.25%	53.0	1.2	
33													
34		2018 Ending Balance									3,340.2	154.6	4.63%
35		2018 Opening Balance									3,239.3	150.7	4.65%
36		**Mid-Year Balance**									**3,289.7**	**152.7**	**4.64%**
37													
38	**Note 1**	In accordance with Commission Direction 4 in Decision 22570-D01-2018, the 2018 actual debt rate cost is 4.69%											

ATCO Electric Transmission (AET)
SCHEDULE OF DEBT CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2017
($Millions)

2017 Actual

Line No.	Cross-Reference	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate
1		LT Adv. - Parent											
2			Y	1990-11-30	2020	11.77%	22.4	0.2	22.2	11.81%	22.4	2.6	
3			Z	1991-12-18	2022	9.92%	29.3	0.4	28.9	9.98%	29.3	2.9	
4			AA	1992-12-08	2023	9.40%	13.8	0.1	13.6	9.45%	13.8	1.3	
5			1999	1999-08-01	2019	6.80%	43.1	0.3	42.8	6.84%	43.1	2.9	
6			2004	2004-01-23	2019	5.43%	34.3	0.2	34.1	5.47%	34.3	1.9	
7			2004	2004-11-18	2034	5.90%	71.0	0.4	70.5	5.94%	70.7	4.2	
8			2005	2005-11-30	2035	5.18%	56.3	0.4	55.9	5.22%	56.0	2.9	
9			2006	2006-11-20	2021	4.80%	59.2	0.3	58.9	4.84%	59.1	2.9	
10			2006	2006-11-20	2036	5.03%	59.2	0.4	58.8	5.07%	59.0	3.0	
11			2007	2007-11-01	2037	5.56%	79.1	0.5	78.6	5.60%	78.8	4.4	
12			2008	2008-05-26	2028	5.56%	29.3	0.2	29.1	5.63%	29.1	1.6	
13			2008	2008-05-26	2038	5.58%	44.0	0.3	43.7	5.61%	43.9	2.5	
14			2009	2009-03-06	2024	6.22%	68.0	0.4	67.5	6.27%	67.8	4.3	
15			2009	2009-03-07	2039	6.50%	85.6	0.6	85.0	6.55%	85.2	5.6	
16			2010	2010-11-10	2050	4.95%	73.3	0.5	72.7	4.99%	72.8	3.6	
17			2011	2011-10-24	2041	4.54%	192.6	1.2	191.4	4.58%	191.7	8.8	
18			2011	2011-10-24	2061	4.59%	77.0	0.5	76.5	4.63%	76.6	3.5	
19			2012	2012-09-10	2042	3.81%	319.9	2.0	317.9	3.84%	318.3	12.2	
20			2012	2012-09-10	2062	3.83%	127.8	0.8	127.0	3.86%	127.1	4.9	
21			2012	2012-11-14	2052	3.86%	162.4	1.0	161.4	3.89%	161.6	6.3	
22			2013	2013-09-09	2043	4.72%	241.0	1.5	239.5	4.77%	239.7	11.4	
23			2013	2013-09-18	2063	4.86%	75.0	0.6	74.4	4.90%	74.5	3.7	
24			2013	2013-11-07	2053	4.56%	225.0	1.4	223.6	4.60%	223.7	10.3	
25			2014	2014-09-05	2044	4.09%	555.0	3.3	551.7	4.13%	552.1	22.8	
26			2014	2014-10-17	2054	4.09%	180.0	1.2	178.8	4.13%	178.9	7.4	
27			2015	2015-07-27	2045	3.96%	110.0	0.7	109.3	4.00%	109.4	4.4	
28			2015	2015-10-29	2055	4.21%	185.0	1.2	183.8	4.25%	183.9	7.8	
29											3,202.7	150.2	4.69%
30		Short-term Debt				1.50%	36.6		36.6	1.50%	36.6	0.5	
31		Notes Payable											
32		2017 Ending Balance									3,239.3	150.7	4.65%
33		2017 Opening Balance									3,150.9	152.6	4.84%
34		**Mid-Year Balance**									**3,195.1**	**151.6**	**4.75%**

ATCO Electric Transmission (AET)
SCHEDULE OF PREFERRED SHARE CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

2018 Actual

Line No.	Cross-Reference	Series	Issue Date	Dividend Rate	Stated Value of Issue	Underwriting Discount & Expense	Net Proceeds Outstanding	Carrying Cost of Issue	Average Embedded Cost Rate
1		V	2007	4.60%	27.9	-	27.9	1.3	4.60%
2		1	2007	4.60%	38.9	-	38.9	1.8	4.60%
3		4	2010	2.24%	24.9	-	24.9	0.6	2.24%
4									
5		Current Year-End Balance			91.7	-	91.7	3.6	3.96%
6		Prior Year-End Balance			91.7	-	91.7	3.6	3.96%
7		Total			183.3		183.3	7.3	3.96%
8		Mid-Year Balance			91.7		91.7	3.6	3.96%
9									

2017 Actual

Line No.	Cross-Reference	Series	Issue Date	Dividend Rate	Stated Value of Issue	Underwriting Discount & Expense	Net Proceeds Outstanding	Carrying Cost of Issue	Average Embedded Cost Rate
10		V	2007	4.60%	27.9	-	27.9	1.3	4.60%
11		1	2007	4.60%	38.9	-	38.9	1.8	4.60%
12		4	2010	2.24%	24.9	-	24.9	0.6	2.24%
13									
14		Current Year-End Balance			91.7	-	91.7	3.6	3.96%
15		Prior Year-End Balance			91.7	-	91.7	3.6	3.89%
16		Total			183.3		183.3	7.2	3.93%
17		Mid-Year Balance			91.7		91.7	3.6	3.93%

ATCO Electric Transmission (AET)
SUMMARY OF OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Acct No.	Description	Cross-Reference	2018 Actual	2018 Approved*	2017 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
		Direct Operation & Maintenance Expense							
1	560	Supervision and Engineering		2.9	-	3.5	(0.5)	-15.4%	
2	561	Control Centre Operations		3.7	-	3.4	0.4	11.4%	
3	562	Station Equipment Expenses		8.5	-	11.4	(2.8)	-25.0%	**Note 1**
4	563/569	Overhead Lines Expenses & Operation Maintenance		2.5	-	3.6	(1.1)	-30.6%	**Note 2**
5	566	Miscellaneous Transmission Expense		39.6	-	38.4	1.2	3.1%	
6	567	Right of Way Payments		6.7	-	6.7	0.1	1.0%	
7	571.1	Vegetation Management		10.9	-	6.7	4.2	63.0%	**Note 3**
8	575	IT Support		3.0	-	3.0	(0.1)	-2.8%	
9				77.9	-	76.6	1.3	1.7%	
10									
11		Isolated Generation Operation & Maintenance		4.5	-	5.5	(1.0)	-17.8%	**Note 4**
12				4.5	-	5.5	(1.0)	-17.8%	
13									
14		**Total Operation and Maintenance Costs**		**82.4**	**-**	**82.1**	0.3	**0.4%**	
15									
16		Allocated Administrative and General	Sch 3.1-T	46.0	-	41.8	4.2	10.0%	
17		Taxes Other Than Income		45.0	-	45.7	(0.7)	-1.5%	
18				91.0	-	87.5	3.5	4.0%	
19									
20				173.5	-	169.6	3.8	2.3%	
21									
22		Farms, Irrigation Transmission Operating Costs		0.8	-	0.8	(0.0)	-5.4%	
23									
24		**Total Transmission O&M Costs**	Sch 1.0-T	**174.2**	**-**	**170.4**	3.8	**2.2%**	

Variance Explanations

Note 1 2018 Actuals are lower than 2017 actuals ($2.8) due to the reclassification of Network Operations Centre costs from USA 562 to USA 561 ($1.1), a reduction in labour ($0.9) and contractor services ($0.2) due to work aggregation and prioritization initiatives as well as a reduction in outside services ($0.4), materials ($0.1), and IT ($0.1) costs.

Note 2 2018 Actuals are lower than 2017 Actuals by ($1.1) due to reduced aircraft costs ($0.5), contractor costs ($0.4), equipment hours ($0.1) and materials ($0.1), largely due to work aggregation and maintenance prioritization initiatives.

Note 3 2018 Actuals are higher than 2017 Actuals by ($4.2) mainly due to advancing mechanical programs to accelerate the conversion to lower-cost herbicide treatments ($3.9) and an increased requirement for treatment of critical sites ($0.3).

Note 4 2018 Actuals are lower than 2017 Actuals by ($1.0) mainly due to reduced maintenance labour as a result of the Garden River Interconnection ($0.6) and renewable projects as well as maintenance prioritization and work aggregation initiatives ($0.4).

***** In accordance with the guidance provided under Section 4.3.3 for AUC Rule 005, whereby interim rates are in place pending a final decision by the AUC, AET has provided a comparison of its 2018 Actuals against its prior year actuals.

ATCO Electric Transmission (AET)
SUMMARY OF OPERATING AND MAINTENANCE EXPENSE (CORPORATE)
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Acct. No.	Description	Cross-Reference	2018 Actual	2018 Approved*	2017 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
		Direct Operation & Maintenance Expense							
1	920	General Administration		9.2	-	9.2	(0.0)	-0.1%	
2	921	Office Supplies and Expenses		13.2	-	7.8	5.4	68.5%	**Note 1**
3	923	Outside Services Employed		1.6	-	1.6	0.0	0.3%	
4	924	Insurance Premiums		3.3	-	3.3	0.0	0.9%	
5	925	Injuries and Damages		(0.0)	-	0.7	(0.7)	-102.9%	
6	928	Board Expenses		1.9	-	2.6	(0.7)	-25.9%	
7	930.2	Miscellaneous General Expenses		17.4	-	15.6	1.7	11.1%	**Note 2**
8	931.1	Head Office Rent		1.7	-	1.5	0.2	10.0%	
9	934	IT G&A Expense	`	3.5	-	3.8	(0.3)	-7.7%	
10	941	Board Expenses Disallowed		1.1	-	2.1	(1.0)	-46.6%	**Note 3**
11	935.2	Maintenance Company Owned Houses		0.1	-	0.3	(0.1)	-46.3%	
12				53.0	-	48.5	4.5	9.4%	
13		**Non-utility Items**							
14		Donations		(0.4)	-	(0.6)	0.1	-19.9%	**Note 1**
15		Disallowed Head Office Costs		(0.6)	-	(0.6)	(0.0)	0.1%	
16		License Fees		(4.6)	-	(3.2)	(1.4)	43.7%	**Note 1**
17		Disallowed Aircraft		(0.2)	-	(0.1)	(0.0)	30.3%	
18		Legal Cost in Excess of Board Scale		(1.1)	-	(2.1)	1.0	-46.6%	**Note 3**
19		Pension - COLA		(0.1)	-	(0.1)	0.0	-14.0%	
20				(7.0)	-	(6.6)	(0.4)	5.3%	
21									
22		**Total Administration and General**	Sch 3.0-T	**46.0**	**-**	**41.8**	**4.2**	10.0%	
23									
24		Total Labour and Fringe		9.1	-	11.1	(2.0)	-17.7%	
25		Total Other		36.9	-	30.7	6.2	20.1%	
26		Total Administration and General		46.0	-	41.8	4.2	10.0%	

Variance Explanations

Note 1 2018 Actuals are higher than 2017 Actuals by ($5.4) mainly due to severance payments incurred ($5.7) and increased license fees ($1.4), these cost are offset by the reclassification of fringe costs to USA 920 ($1.5) and lower donations ($0.1). The costs incurred for donations and licensing fees are removed as a non-utility item on lines 14 and 17, respectively.

Note 2 2018 Actuals are higher than 2017 Actuals by ($1.7) mainly due to higher Head Office Costs ($3.0) partially offset by lower support required for the Alberta PowerLine WFMAC project ($1.0) and lower cost of goods sold related to other affiliates ($0.3).

Note 3 2018 Actuals are lower than 2017 Actuals by ($1.0) mainly due to lower disallowed proceeding costs in 2018 before the Commission ($0.8) as well as the 2016 accrual reversal that was inadvertently applied to USA 923 instead of USA 941. Disallowed regulatory proceeding costs are removed as a non-utility item on line 19.

***** In accordance with the guidance provided under Section 4.3.3 for AUC Rule 005, whereby interim rates are in place pending a final decision by the AUC, AET has provided a comparison of its 2018 Actuals against its prior year actuals.

ATCO Electric Transmission (AET)
SUMMARY OF DEPRECIATION EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.		Description	Cross-Reference	2018 Actual	2018 Approved*	2017 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1		Transmission		178.4	-	174.9	3.4	2.0%	
2		Amortization of Differences		4.8	-	4.8	0.0	0.1%	
3		**Subtotal**		183.2	-	179.7	3.5	1.9%	
4									
5		**Direct General PP&E**							
6		Structures & Improvements		2.8	-	2.7	0.1	2.0%	
7		Office Furniture and Equipment		0.8	-	0.8	0.0	2.7%	
8		Computer Equipment		0.1	-	0.1	(0.0)	-2.9%	
9		Transportation Equipment		3.7	-	4.1	(0.4)	-9.0%	
10		Tools & Instruments		3.2	-	2.4	0.8	33.8%	
11		Communication Equipment		-	-	-	-	0.0%	
12		Housing		0.0	-	0.0	(0.0)	0.0%	
13		Leasehold Improvements		1.9	-	1.7	0.1	8.4%	
14		Software		7.1	-	5.8	1.2	21.1%	
15		Amortization of Differences		0.6	-	0.6	0.0	0.3%	
16		**Subtotal**		20.2	-	18.3	1.9	10.4%	
17									
18		**Allocated General PP&E**		-	-	-	-	0.0%	
19									
20		**Transmission Gross Provision**		203.3	-	198.0	5.4	2.7%	
21									
22		Farms, Irrigation Transmission		1.7	-	1.7	0.0	0.3%	
23									
24		**Total Transmission Gross Depreciation Expense**		205.0	-	199.7	5.4	2.7%	
25									
26		Depreciation Gross Provision - Life		164.7	-	161.8	2.9	1.8%	
27		Depreciation Gross Provision - Net Salvage		40.3	-	37.8	2.5	6.6%	
28				205.0	-	199.7	5.4	2.7%	
29									
30		Gross Depreciation Expense		205.0	-	199.7	5.4	2.7%	
31		Vehicle Depreciation Capitalized		(1.9)	-	(3.1)	1.2	-39.7%	
32		Amortization of Contributions		(10.1)	-	(9.8)	(0.4)	3.7%	
33		**Total Depreciation and Amortization Expense**		193.0	-	186.8	6.2	3.3%	
34									
35		Refund of Pension Contributions Capitalized		-	-	(38.4)	38.4	-100.0%	
36									
37		**Total Depreciation and Amortization Expense (including Refund of Pension contributions capitalized)**	Sch 1.0-T	193.0	-	148.4	44.6	30.1%	
38									
39		**Variance explanation**							
40									
41	**Note 1**	The 2018 depreciation expense is higher than 2017 mainly due to the refund of Pension Contributions Capitalized in 2017 in addition to							
42		depreciation expense on 2018 additions and a full year depreciation impact for 2017 additions.							

***** In accordance with the guidance provided under Section 4.3.3 for AUC Rule 005, whereby interim rates are in place pending a final decision by the AUC, AET has provided a comparison of its 2018 Actuals against its prior year actuals.

ATCO Electric Transmission (AET)
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

CAPITAL ASSETS

Line No.	Property Group	Cross-Reference	Balance at 12/31/2017	Prior Year Disallowances & Opening Balance Adjustments	Revised Balance at 12/31/2017	2018 Additions	2018 Retirements	2018 Transfers	2018 Adjustments	2018 Pension Disallowance	Balance at 12/31/2018
				Note 1							
1	Transmission		6,815.8	(1.5)	6,814.3	237.1	(8.5)	(0.8)	1.2	(0.3)	7,043.1
2											
3	**Direct General PP&E**										
4	Land		4.9	-	4.9	0.0	(0.0)	(0.0)	-	-	4.9
5	Structures and Improvements		116.8	-	116.8	2.7	(0.0)	-	-	-	119.5
6	Office Furniture and Equipment		12.0	-	12.0	0.7	(0.0)	-	-	-	12.7
7	Computer Equipment		0.4	-	0.4	0.0	(0.1)	-	-	-	0.3
8	Transportation Equipment		58.1	-	58.1	0.3	(4.4)	(0.1)	-	-	53.9
9	Tools and Instruments		30.4	-	30.4	1.7	(0.7)	-	-	-	31.3
10	Communication Equipment		-	-	-	-	-	-	-	-	-
11	Housing		0.2	-	0.2	-	-	(0.1)	(0.1)	-	-
12	Leasehold Improvements		13.5	-	13.5	1.9	(1.4)	-	-	-	14.0
13	Software		59.2	-	59.2	14.5	(1.8)	-	-	-	71.9
14	**Subtotal**		295.6	-	295.6	21.8	(8.6)	(0.3)	(0.1)	-	308.4
15											
16	**Subtotal - Utility Plant in Service**	Sch 2.1-T	7,111.4	(1.5)	7,109.9	258.9	(17.1)	(1.1)	1.1	(0.3)	7,351.5
17											
18	Capital Work in Progress (CWIP)		205.0	(2.9)	202.1	(12.5)	-	-	-	-	189.6
19											
20	**Total Transmission**		7,316.3	(4.4)	7,311.9	246.4	(17.1)	(1.1)	1.1	(0.3)	7,541.1

21

22 Note 1 The prior year disallowances and opening rate base balance adjustments of ($4.4) includes ($1.5) for disallowances for AUC Decision 21206-D01-2017, and ($2.9) related to prior period adjustments.

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross-Reference	Balance at 12/31/2017	Prior Year Disallowances & Opening Balance Adjustments	Revised Balance at 12/31/2017	Depreciation Provision	2018 Retirements	2018 Transfers	2018 Adjustments	2018 Net Salvage	Balance at 12/31/2018
				Note 1							
21	Transmission		1,312.4	(0.1)	1,312.3	183.2	(8.5)	(0.5)	-	(4.7)	1,481.9
22											
23	**Direct General PP&E**										
24	Land		(0.1)	-	(0.1)	-	(0.0)	-	-	-	(0.1)
25	Structures and Improvements		18.8	-	18.8	2.7	(0.0)	-	-	0.5	22.0
26	Office Furniture and Equipment		4.8	-	4.8	0.8	(0.0)	-	-	-	5.6
27	Computer Equipment		0.3	-	0.3	0.1	(0.1)	-	-	-	0.3
28	Transportation Equipment		21.5	-	21.5	3.9	(4.4)	(0.1)	-	1.7	22.6
29	Tools and Instruments		10.0	-	10.0	3.2	(0.7)	-	-	-	12.5
30	Communication Equipment		-	-	-	-	-	-	-	-	-
31	Housing		0.3	-	0.3	0.0	-	0.0	-	0.2	0.5
32	Leasehold Improvements		3.2	-	3.2	1.5	(1.4)	-	-	-	3.2
33	Software		28.9	-	28.9	7.8	(1.8)	-	-	-	34.9
34	**Subtotal**		87.8	-	87.8	20.2	(8.6)	(0.1)	-	2.3	101.6
35											
36	**Total Transmission**	Sch 2.1-T	1,400.2	(0.1)	1,400.1	203.3	(17.1)	(0.5)	-	(2.3)	1,583.5

37

38 Note 1 The prior year disallowances and opening rate base balance adjustments of ($0.1) is for the disallowances related to AUC Decision 21206-D01-2017.

39

40 * AFUDC is a component of all categories and is therefore not disclosed separately in this continuity schedule.

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

			2018 Actual				2017 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Prior Year	Var. %	Higher/(Lower) Additions Actual to Prior Year	Var. %
1		**CAPITAL MAINTENANCE**												
2	50010	Transmission Capital Maintenance - Substations	11.1	10.8	10.3	11.6	13.2	7.9	10.0	11.1	3.0	38%	0.3	3%
3	50020	Transmission Capital Maintenance - Lines	6.8	13.8	13.0	7.6	4.7	13.4	11.2	6.8	0.4	3%	1.8	16%
4	50040	Transmission System Right-of-Way	0.3	1.7	2.0	0.0	(0.0)	1.8	1.4	0.3	(0.1)	-3%	0.5	38%
5	50041	Transmission Rights-of-Way Widening	0.1	4.7	4.8	0.0	0.9	4.7	5.6	0.1	(0.0)	-1%	(0.8)	-14%
6	50060	Substation Rebuilds	10.1	23.7	26.2	7.7	12.4	14.2	16.4	10.1	9.5	67%	9.7	59%
7	50130	Replace or Rebuild Major Transmission Apparatus	4.1	14.6	9.4	9.3	6.4	11.0	13.2	4.1	3.6	33%	(3.8)	-29%
8	50170	Transmission Emergency Apparatus	(0.1)	1.4	0.1	1.3	4.7	1.2	6.0	(0.1)	0.2	12%	(5.9)	-99%
9	50190	Transmission Line Ground Clearance	1.1	0.8	0.4	1.5	9.1	0.5	8.5	1.1	0.4	84%	(8.1)	-95%
10	50220	Transmission Line Rebuilds	0.8	4.1	-	4.8	-	0.8	-	0.8	3.3	100%	-	0%
11	50463	Kearl 9L101/9L32 Line Relocation	0.1	0.8	-	0.9	-	0.1	-	0.1	0.7	100%	-	0%
12	50500	McNeill HVDC Control Replacement	-	-	-	-	-	0.0	0.0	-	(0.0)	-100%	(0.0)	-100%
13	50940	Transmission Double Circuit	3.5	0.6	1.9	2.1	5.2	0.8	2.5	3.5	(0.2)	-27%	(0.5)	-21%
14	50960	Mitigate Equipment Problems	2.3	2.6	4.6	0.3	3.2	8.6	9.5	2.3	(6.1)	-70%	(4.9)	-51%
15			40.3	79.6	72.7	47.2	59.7	64.9	84.3	40.3	14.7	23%	(11.6)	-14%
16		**TELECOMMUNICATION**												
17	50400	Telecommunication Capital Maintenance	1.7	5.1	4.0	2.8	3.6	2.2	4.0	1.7	2.9	100%	(0.0)	-1%
18	59911	Telecom Site Power Backup	0.1	0.1	0.2	-	0.1	0.0	0.0	0.1	0.1	100%	0.2	100%
19	59943	Grande Prairie Area Telecom Reliability	(0.0)	0.5	0.5	-	3.4	4.0	7.4	(0.0)	(3.6)	-88%	(7.0)	-94%
20	59946	Mobile Communication System	0.3	0.0	0.0	0.3	0.3	0.0	0.0	0.3	0.0	100%	0.0	100%
21	59948	Microwave Capacity Upgrade	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0%	(0.0)	-100%
22	59955	Network Mulitplexor Upgrade	0.7	2.0	2.7	(0.0)	5.4	3.1	7.8	0.7	(1.1)	-36%	(5.1)	-65%
23	50425	Telecom Tower Replacements	2.0	2.2	3.5	0.7	1.6	8.8	8.3	2.0	(6.6)	-75%	(4.8)	-58%
24	50457	Telecom Building Replacements/Refurbishments	1.2	0.5	0.9	0.8	0.3	1.4	0.4	1.2	(0.8)	-61%	0.5	100%
25	50455	Replacement of End of Life Radios	0.0	0.7	0.0	0.8	0.2	0.2	0.4	0.0	0.6	100%	(0.4)	-100%
26	50456	Telecom Capacity & Reliability Upgrade Projects	1.2	3.4	0.9	3.7	0.2	1.2	0.1	1.2	2.2	100%	0.8	100%
27	50422	Mobile Radio Expansion	4.4	1.8	1.8	4.4	1.1	3.3	-	4.4	(1.5)	-47%	1.8	100%
28			11.9	16.3	14.6	13.6	16.3	24.2	28.6	11.9	(7.9)	-33%	(14.0)	-49%
29		**SCADA / EMS**												
30	50800	Substation Control Expansion Program	(0.0)	(0.0)	-	(0.0)	-	(0.0)	-	(0.0)	0.0	-79%	-	0%
31	50900	Operational Information Systems	0.1	0.7	0.0	0.8	1.7	0.6	2.3	0.1	0.1	11%	(2.3)	-100%
32	59919	Regulatory Compliance & Security Programs	1.3	3.3	4.0	0.6	1.1	0.6	0.3	1.3	2.8	100%	3.7	100%
33			1.4	4.0	4.0	1.4	2.8	1.2	2.6	1.4	2.8	100%	1.4	55%
34														
35	00073	Fort McMurray Fire 2016 (Transmission)	0.0	-	-	0.0	-	0.6	0.6	0.0	(0.6)	-100%	(0.6)	-100%
36														
37		**TOTAL CAPITAL MAINTENANCE**	53.6	99.9	91.3	62.2	78.9	90.9	116.2	53.6	9.0	10%	(24.9)	-21%
38														
39		**DIRECT ASSIGNED PROJECTS SYSTEM**												
40	58001	Edmonton-Calgary 500 kV East Route	-	19.8	19.8	0.0	(0.0)	4.7	4.7	-	15.0	100%	15.0	100%
41	58005	Southeast Bulk System Reinforcement	(0.1)	0.8	0.7	0.0	0.0	1.1	1.2	(0.1)	(0.3)	-24%	(0.5)	-42%
42	53043	P1784 Rycroft Transmission Reinforcement	0.4	0.4	-	0.8	-	0.4	-	0.4	0.0	11%	-	0%
43	54904	Jasper Transmission Interconnection	22.6	35.4	-	58.0	6.2	16.4	-	22.6	19.0	100%	-	0%
44	55001	Salt Creek - 240-144kv Substation	0.1	1.5	1.6	(0.0)	0.0	(0.1)	(0.2)	0.1	1.6	-100%	1.8	-100%
45	55126	Ells – 9L76/9L08 240kV D/C Line	-	-	-	-	10.6	0.2	-	-	(0.2)	-100%	-	0%
46	55127	9L95 Development	-	-	-	-	7.5	0.2	-	-	(0.2)	-100%	-	0%

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Project	Description	2018 Actual CWIP Balance	2018 Actual Cap Expend	2018 Actual Cap Adds	2018 Actual CWIP Balance		2017 Actual CWIP Balance	2017 Actual Cap Expend	2017 Actual Cap Adds	2017 Actual CWIP Balance	Higher/(Lower) Expenditures Actual to Prior Year	Var. %	Higher/(Lower) Additions Actual to Prior Year	Var. %
47	55322	Algar Area System Reinforcement	(0.0)	0.0	0.0	0.0		0.0	(0.1)	(0.1)	(0.0)	0.1	-100%	0.1	-100%
48	55703	Heart Lake Station Expansion	0.0	0.0	0.1	(0.0)		0.0	(0.2)	(0.2)	0.0	0.2	-100%	0.3	-100%
49	55732	Livock Interconnection (55737)	0.0	0.1	0.1	(0.0)		0.4	1.0	1.4	0.0	(0.9)	-90%	(1.3)	-92%
50	55737	Thickwood Development	45.4	60.4	105.8	-		6.5	38.9	-	45.4	21.5	55%	105.8	100%
51	56539	Cold Lake Development	(0.0)	0.0	0.0	(0.0)		(0.0)	0.2	0.2	(0.0)	(0.2)	-95%	(0.1)	-84%
52	56772	Nevis Transformer	-	0.1	-	0.1		-	-	-	-	0.1	100%	-	0%
53	57102	9LX02 (Boundary-Tinchebray)	-	-	-	-	**Note 1**	0.5	-	-	0.5	-	0%	-	0%
54	57151	St. Paul Area – Watt Lake and Whitby Lake Substations	0.0	0.0	0.0	(0.0)		-	0.0	0.0	0.0	(0.0)	-60%	0.0	100%
55	57155	Cold Lake Area - Bourque-Bonnyville	0.0	0.2	0.2	-		(0.0)	1.7	1.6	0.0	(1.5)	-91%	(1.4)	-89%
56	57157	St. Paul Substation and Line	0.0	1.1	1.1	0.0		0.0	2.6	2.6	0.0	(1.5)	-57%	(1.5)	-57%
57	53594	Grande Prairie Transmission Reinforcement	0.2	0.0	-	0.2		0.1	0.1	-	0.2	(0.0)	-71%	-	0%
58	57159	Central East Plan 1	0.3	0.1	-	0.4		0.1	0.1	-	0.3	(0.0)	-12%	-	0%
59	58112	Central East Transfer Out	-	0.2	-	0.2		-	-	-	-	0.2	100%	-	0%
60		Various Other Projects below $0.0 individually	0.0	0.1	0.1	0.0		(0.0)	(0.0)	(0.1)	0.0	0.1	-100%	0.2	-100%
61		**TOTAL DIRECT ASSIGNED PROJECTS - SYSTEM**	69.0	120.4	129.6	59.7		32.1	67.2	11.2	69.5	53.2	79%	118.4	100%
62															
63		**DIRECT ASSIGNED PROJECTS - CUSTOMER**													
64	51074	Fort Nelson Remedial Action Scheme	0.3	0.0	0.3	0.0		0.3	0.0	-	0.3	0.0	100%	0.3	100%
65	51760	Fort Saskatchewan WAGF	0.1	0.0	-	0.1		-	0.1	-	0.1	(0.0)	-94%	-	0%
66	51162	Blumenort - Windy Hills 144kV Transmission Line	1.4	-	-	1.4		1.4	0.1	-	1.4	(0.1)	-100%	-	0%
67	51181	Three Creeks Power Plant	15.3	-	-	15.3		14.9	0.4	-	15.3	(0.4)	-100%	-	0%
68	51440	Whitetail Peaking Station Interconnection	1.3	0.1	-	1.4		1.2	0.1	-	1.3	(0.0)	-19%	-	0%
69	51745	Wabasca 25kV Breaker Addition	0.4	-	-	0.4		0.4	0.0	-	0.4	(0.0)	-100%	-	0%
70	51750	Eureka River 861S Capacity Increase	0.0	0.1	0.1	0.0		1.9	3.3	5.2	0.0	(3.3)	-98%	(5.1)	-98%
71	53034	Ksituan River 754S Capacity Upgrade	4.1	1.8	-	5.9		0.7	3.4	-	4.1	(1.6)	-47%	-	0%
72	53340	Swan Hills Phase 1 Gas Turbine	0.0	-	-	0.0		-	0.0	-	0.0	(0.0)	-100%	-	0%
73	53440	Thornton New POD (Kakwa POD)	(0.0)	0.0	(0.0)	0.0		0.0	(0.2)	(0.2)	(0.0)	0.3	-100%	0.2	-97%
74	53455	M.D. Greenview Load	-	0.5	-	0.5		-	-	-	-	0.5	100%	-	0%
75	53593	Grande Prairie	4.8	1.5	-	6.3		1.6	3.2	-	4.8	(1.7)	-53%	-	0%
76	54020	Muir POD	12.1	4.6	16.8	-		1.0	11.1	-	12.1	(6.5)	-58%	16.8	100%
77	54501	Wapiti 823S Capacity Addition	-	0.4	0.4	-	**Note 2**	0.6	4.1	4.0	0.6	(3.6)	-90%	(3.6)	-90%
78	55119	Generator Capacity Increase	0.0	0.1	-	0.1		-	0.0	-	0.0	0.1	100%	-	0%
79	55187	Service for AOSC MacKay SAGD	0.0	0.0	0.0	(0.0)		-	(0.3)	(0.3)	0.0	0.3	-100%	0.3	-100%
80	55325	Algar Expansion	0.0	0.0	0.0	(0.0)		0.0	(0.3)	(0.3)	0.0	0.3	-100%	0.3	-100%
81	55579	Secord Substation	(0.0)	0.0	(0.0)	(0.0)		0.0	(0.1)	(0.1)	(0.0)	0.2	-100%	0.1	-91%
82	55622	Cheecham POD	-	0.0	(0.0)	0.0		0.0	(0.1)	(0.1)	-	0.1	-100%	0.1	-80%
83	55633	Surmount II (Stage 3)	0.0	0.0	0.0	0.0		(0.0)	(0.2)	(0.3)	0.0	0.3	-100%	0.3	-100%
84	55636	Kearl 9900S Substation DTS Increase	0.0	-	(0.0)	0.0		0.0	0.1	0.1	0.0	(0.1)	-100%	(0.1)	-100%
85	55655	Bohn POD	0.0	0.0	0.0	0.0		(0.0)	(0.1)	(0.1)	0.0	0.1	-100%	0.1	-100%
86	55706	Edwards Lake Substation Connection	0.0	0.0	-	0.0		0.4	(0.3)	-	0.0	0.3	-101%	-	0%
87	55709	CNRL Kirby North	0.0	0.1	-	0.1		-	0.0	-	0.0	0.1	100%	-	0%
88	55725	Saleski	(0.0)	-	-	(0.0)		0.0	(0.0)	-	(0.0)	0.0	-100%	-	0%
89	55753	MD Greenview Load and Reliability (Merrit)	-	0.1	-	0.1		-	-	-	-	0.1	100%	-	0%
90	55785	Kettle River Substation & 240kV Line Tap	0.0	0.0	-	0.0		-	0.0	-	-	(0.0)	-57%	-	0%
91	55797	Grand Rapids MacKay POD	0.0	0.0	0.0	0.0		(0.0)	0.1	0.0	0.0	(0.0)	-66%	(0.0)	-39%
92	56352	Mahihkan 837S Substation 25 kV Breaker Addition	(0.0)	0.0	0.0	(0.0)		1.4	0.1	1.5	(0.0)	(0.1)	-94%	(1.5)	-100%

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

			2018 Actual					2017 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance		CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Prior Year	Var. %	Higher/(Lower) Additions Actual to Prior Year	Var. %
93	56655	Kent Generation	0.0	(0.0)	-	0.0		0.7	(0.7)	-	0.0	0.7	-100%	-	0%
94	56810	Grizzly Bear Wind Facility Connection	1.9	0.1	-	1.9		1.8	0.0	-	1.9	0.0	70%	-	0%
95	56815	Paintearth Wind Project	0.6	0.1	-	0.7		-	0.6	-	0.6	(0.5)	-84%	-	0%
96	56820	Halkirk II Wind Power Facility	0.3	0.1	-	0.4		-	0.3	-	0.3	(0.2)	-57%	-	0%
97	56865	Wainwright	0.1	0.0	-	0.1		0.1	0.0	-	0.1	(0.0)	-69%	-	0%
98	57120	Central East Clearance Mitigation	(0.0)	-	0.0	(0.0)		(0.0)	(0.0)	(0.0)	(0.0)	0.0	-100%	0.0	-113%
99	58180	Spirit River POD Substation	-	0.1	0.1	(0.0)	**Note 3**	6.4	7.8	13.9	0.3	(7.7)	-99%	(13.9)	-100%
100	58181	Simonette 733S Substation Capacity Upgrade	-	0.0	0.0	(0.0)	**Note 4**	0.0	0.2	0.1	0.2	(0.2)	-97%	(0.1)	-91%
101	58215	Sharp Hills Windfarm	0.4	2.6	-	3.0		0.3	0.1	-	0.4	2.5	100%	-	0%
102	58225	Garden Plain Wind	0.0	0.1	-	0.2		-	0.0	-	0.0	0.1	100%	-	0%
103	58562	Hand Hills Wind Power Facility	0.7	(0.0)	-	0.7		0.7	0.0	-	0.7	(0.0)	-100%	-	0%
104	58569	Hand Hills Wind Power Facility	0.5	0.0	-	0.5		0.5	0.0	-	0.5	0.0	81%	-	0%
105	58578	Hand Hills WAGF	0.1	(0.0)	-	0.1		-	0.1	-	0.1	(0.1)	-100%	-	0%
106	58574	Forestberg Area Solar	-	0.1	-	0.1		-	-	-	-	0.1	100%	-	0%
107	58843	Wheatland Wind New POS	0.3	0.1	-	0.4		-	0.3	-	0.3	(0.2)	-72%	-	0%
108	58844	Echo Wind Power New POS	0.1	0.2	-	0.3		-	0.1	-	0.1	0.1	100%	-	0%
109	58922	Eyre 558S Substation Interconnection	0.3	0.0	-	0.3		0.2	0.0	-	0.3	0.0	53%	-	0%
110	58923	Currant Lake Substation	4.1	0.3	-	4.4		3.8	0.2	-	4.1	0.1	46%	-	0%
111	58924	Armitage Substation	4.7	0.4	-	5.1		4.5	0.3	-	4.7	0.1	44%	-	0%
112	58925	Cavendish Substation	5.1	0.4	-	5.5		4.8	0.3	-	5.1	0.1	36%	-	0%
113	58965	Heartland Pump Station	3.0	1.2	3.8	0.5		1.1	2.0	-	3.0	(0.8)	-39%	3.8	100%
114	58970	Bohn 913S Substation Transformer Addition	-	0.0	0.0	-	**Note 5**	3.9	0.8	4.6	0.1	(0.8)	-98%	(4.6)	-100%
115	58971	Bauer 918S Substation Transformer Addition	0.0	0.0	0.0	0.0		(0.0)	0.1	0.1	0.0	(0.1)	-97%	(0.1)	-91%
116	53441	Thornton DTS Increase	-	-	-	-		0.1	(0.1)	-	-	0.1	-100%	-	0%
117	55605	Line Tap	0.1	0.0	-	0.1		0.1	0.0	-	0.1	(0.0)	-93%	-	0%
118	58145	Red Deer Battery Energy Storage System	0.3	0.0	-	0.3		0.1	0.2	-	0.3	(0.2)	-95%	-	0%
119	58526	Oyen Wind Power Project	0.3	0.0	-	0.4		0.1	0.2	-	0.3	(0.2)	-81%	-	0%
120		Various Other Projects below $0.0 individually	0.3	0.2	0.1	0.5		0.1	0.3	0.1	0.3	(0.1)	-34%	(0.1)	-52%
121		**TOTAL DIRECT ASSIGNED PROJECTS - CUSTOMER**	63.0	15.4	21.6	56.9		54.9	37.8	28.5	64.2	(22.4)	-59%	(6.9)	-24%
122															
123		AUC Decision 21206-D01-2017 Directions 4, 5, 6, 7, 8, 10, 18				-		-	(0.3)	(0.3)	-	0.3	-100%	0.3	-100%
124		**TOTAL DIRECT ASSIGNED**	132.0	135.8	151.2	116.6		87.0	104.7	39.4	133.7	31.1	30%	111.8	100%
125															

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

			2018 Actual				2017 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Prior Year	Var. %	Higher/(Lower) Additions Actual to Prior Year	Var. %
126		**TRANSMISSION ISOLATED GENERATION**												
127	90067	Rebuild Jasper Palisades Substation	0.3	(0.0)	-	0.3	0.3	-	-	0.3	(0.0)	-100%	-	0%
128	90120	Distribution Isolated Generation Capital Maintenance	0.0	(0.0)	0.0	(0.0)	0.0	(0.0)	-	0.0	(0.0)	27%	0.0	100%
129	90130	Refurbish/Replace Engines and Turbines	1.3	0.5	0.4	1.3	1.0	1.1	0.8	1.3	(0.6)	-58%	(0.4)	-47%
130	90134	Fort Chipewyan Capacity Increase	(0.0)	0.0	(0.0)	-	(0.0)	-	-	(0.0)	0.0	100%	(0.0)	-100%
131	90136	CUL 43 Replacement	0.0	0.0	0.0	-	0.0	0.0	-	0.0	(0.0)	-38%	0.0	100%
132	90140	Transmission Isolated Operations Capital Maintenance	2.3	0.5	2.3	0.5	1.5	1.7	0.9	2.3	(1.2)	-71%	1.4	100%
133	90150	Indian Cabins Capacity Increase	0.0	(0.0)	-	0.0	-	0.0	-	0.0	(0.0)	-100%	-	0%
134	90400	Install Alternate Power Supply/Renewables	1.3	2.1	0.5	2.9	-	7.3	6.0	1.3	(5.2)	-71%	(5.5)	-92%
135			5.2	3.0	3.2	5.0	2.8	10.1	7.8	5.2	(7.1)	-70%	(4.5)	-58%
136														
137		Total Transmission	190.7	238.8	245.7	183.8	168.7	205.7	163.4	192.4	33.1	16%	82.4	50%
138		Net Salvage			(5.4)				(7.9)					
139		Additions to Property			240.3				155.5					
140														
141		**DIRECT GENERAL PP&E**												
142	80000	Blanket GP&E - Corporate	0.0	-	0.0	-	-	0.0	-	0.0	(0.0)	-100%	0.0	100%
143	81016	Tools and Instruments - Transmission Engineering Substation	0.1	1.0	0.6	0.6	(0.0)	3.7	3.5	0.2	(2.7)	-74%	(3.0)	-84%
144	81046	Transmission Construction	(0.0)	0.0	0.0	(0.0)	0.0	0.4	0.4	(0.0)	(0.4)	-99%	(0.4)	-99%
145	81066	Transmission Asset Mgmt Program	0.4	0.7	1.1	0.0	0.1	0.6	0.3	0.4	0.1	14%	0.8	100%
146	81070	Capital Division Construction Small Tools	0.0	-	0.0	(0.0)	0.0	-	-	0.0	-	0%	0.0	100%
147	84000	Transportation Equipment	0.0	(1.9)	(1.9)	0.0	0.6	(1.0)	(0.4)	0.0	(0.9)	94%	(1.4)	100%
148			0.6	(0.2)	(0.2)	0.6	0.7	3.8	3.8	0.6	(4.0)	-100%	(4.0)	-100%
149		**SOFTWARE**												
150		Enterprise IT	0.2	0.6	0.4	0.4	0.6	2.0	1.2	1.4	(1.4)	-70%	(0.8)	-63%
151		Facilities & Asset Management	3.8	1.6	1.2	4.3	2.1	4.1	2.4	3.8	(2.5)	-61%	(1.2)	-51%
152		IT Infrastructure & Foundational Initiatives	1.5	(0.2)	1.0	0.4	1.5	4.7	4.6	1.5	(4.9)	-100%	(3.6)	-79%
153		Project & Financial Management	4.5	6.9	11.3	0.1	0.5	5.0	1.0	4.5	1.9	37%	10.3	100%
154			10.1	8.9	13.9	5.1	4.7	15.8	9.2	11.2	(6.9)	-44%	4.7	51%
155		**BUILDINGS**												
156	82000	Office Furniture and Equipment	-	0.7	0.7	-	-	-	-	-	0.7	100%	0.7	100%
157	85000	Land, Buildings and Structures	0.6	1.6	2.0	0.2	0.1	0.5	0.1	0.6	1.1	100%	2.0	100%
158	85201	General Leasehold Improvements	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	79%	0.0	100%
159			0.6	2.3	2.7	0.2	0.2	0.5	0.1	0.6	1.8	100%	2.7	100%
160														
161			11.4	11.0	16.5	5.9	5.5	20.1	13.1	12.5				
162		Net Salvage			2.2				1.0					
163		Additions to Property			18.6				14.1					
164														
165		**Total Transmission Capital Additions**	202.1	249.8	258.9	189.6	174.2	225.8	169.6	204.9				
166														
167	Note 1	**2018 Opening WIP has been adjusted as this project has been cancelled and there should have been no Opening 2018 WIP**												
168	Note 2	**2018 Opening WIP has been adjusted by $0.6M as there should have been $4.6M additions in 2017**												
169	Note 3	**2018 Opening WIP has been adjusted by $0.3M as there should have been $14.2M additions in 2017**												
170	Note 4	**2018 Opening WIP has been adjusted by $0.2M as there should have been $0.3M additions in 2017**												
171	Note 5	**2018 Opening WIP has been adjusted by $0.1M as there should have been $4.7M additions in 2017**												

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL CONTRIBUTIONS
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Project	Description	2018 Actual CWIP Balance	2018 Actual Cap Expend	2018 Actual Cap Adds	2018 Actual CWIP Balance	2017 Actual CWIP Balance	2017 Actual Cap Expend	2017 Actual Cap Adds	2017 Actual CWIP Balance	Higher/(Lower) Expenditures Actual to Prior Year	Var. %	Higher/(Lower) Additions Actual to Prior Year	Var. %
1		**DIRECT ASSIGNED PROJECTS**												
2	51074	Fort Nelson Remedial Action Scheme	0.4	-	0.4	(0.0)	0.4	-	-	0.4	-	0%	0.4	100%
3	51162	Blumenort - Windy Hill 144 kV Transmission Line	1.4	-	-	1.4	1.4	-	-	1.4	-	0%	-	0%
4	51181	Carmon Creek Cogen	14.9	0.8	-	15.6	18.9	(4.0)	-	14.9	4.8	-100%	-	0%
5	51440	Whitetail Peaking Station Interconnection	1.6	-	-	1.6	1.6	-	-	1.6	-	0%	-	0%
6	51750	Eureka River Transformer Addition	-	(1.2)	(1.2)	-	-	4.3	4.3	-	(5.5)	-100%	(5.5)	-100%
7	51760	Fort Saskatchewan WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0%	-	0%
8	53034	Ksituan River 754S Capacity Upgrade	1.5	3.6	-	5.1	-	1.5	-	1.5	2.1	100%	-	0%
9	53324	Slave Lake Pulp STS Contract Capacity Increase	(0.1)	-	-	(0.1)	(0.1)	-	-	(0.1)	-	0%	-	0%
10	53440	Thornton New POD (Kakwa POD)	-	-	-	-	-	0.1	0.1	-	(0.1)	-100%	(0.1)	-100%
11	53593	Grande Prairie	-	-	-	-	-	-	-	-	-	0%	-	0%
12	54020	Muir POD	-	5.9	5.9	-	-	-	-	-	5.9	100%	5.9	100%
13	54156	Aspen 240kV Line and Sub	-	-	-	-	-	-	-	-	-	0%	-	0%
14	54281	Bridge Creek 798S Transformer Upgrade	-	-	-	-	-	0.0	0.0	-	(0.0)	-100%	(0.0)	-100%
15	54954	Maxim Power Generator Increase	(0.1)	-	-	(0.1)	(0.0)	(0.0)	-	(0.1)	0.0	-100%	-	0%
16	54955	Maxim Power Milner 2 Expansion	0.1	-	-	0.1	0.0	0.0	-	0.1	(0.0)	-100%	-	0%
17	55080	240 kV Line from 847S to Alternate Source	-	-	-	-	-	-	-	-	-	0%	-	0%
18	55119	Suncor Generator Capacity Increase	-	1.6	-	1.6	-	-	-	-	1.6	100%	-	0%
19	55187	Service for MacKay SAGD	(0.0)	(0.3)	(0.3)	(0.0)	(0.0)	-	-	(0.0)	(0.3)	-100%	(0.3)	-100%
20	55325	Algar Expansion	(0.0)	(0.2)	(0.2)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.2)	100%	(0.2)	100%
21	55579	Secord Substation	(0.0)	(0.3)	(0.3)	(0.0)	(0.0)	(0.1)	(0.1)	(0.0)	(0.1)	86%	(0.1)	86%
22	55605	Peace Hills Power Line Tap	0.3	-	-	0.3	0.3	-	-	0.3	-	0%	-	0%
23	55619	Enbridge Cheecham Breaker Addition	-	-	-	-	-	0.2	0.2	-	(0.2)	-100%	(0.2)	-100%
24	55622	Cheecham POD	0.0	-	-	0.0	0.0	(1.8)	(1.8)	0.0	1.8	-100%	1.8	-100%
25	55631	Quigley 144 kV Line and Substation	-	-	-	-	-	(1.0)	(1.0)	-	1.0	-100%	1.0	-100%
26	55632	Surmont II (Stages 2)	-	-	-	-	-	5.3	5.3	-	(5.3)	-100%	(5.3)	-100%
27	55633	Surmont II (Stages 3)	0.0	-	-	0.0	0.0	-	-	0.0	-	0%	-	0%
28	55666	Enbridge Lynton Pump Station	-	(0.4)	(0.4)	-	-	0.0	0.0	-	(0.4)	-100%	(0.4)	-100%
29	55706	Edwards Lake Substation Connection	-	-	-	-	-	-	-	-	-	0%	-	0%
30	55709	CNRL Kirby North	-	0.1	-	0.1	-	-	-	-	0.1	100%	-	0%
31	55735	Germain Substation and 144kV Line	-	0.6	0.6	-	-	-	-	-	0.6	100%	0.6	100%
32	55780	Round Hill Substation Interconnection	-	-	-	-	-	(0.0)	(0.0)	-	0.0	-100%	0.0	-100%
33	55797	Grand Rapids MacKay POD	-	-	-	-	-	0.3	0.3	-	(0.3)	-100%	(0.3)	-100%
34	56015	Norberg Substation and 144 kV Line	-	-	-	-	-	(0.0)	(0.0)	-	0.0	-100%	0.0	-100%
35	56102	Hughenden 213S Substation Upgrade	-	-	-	-	-	(0.1)	(0.1)	-	0.1	-100%	0.1	-100%
36	56655	Alta Gas Kent - Generator - Central East	(0.0)	-	-	(0.0)	0.6	(0.6)	-	(0.0)	0.6	-100%	-	0%
37	56810	Grizzly Bear Wind Power Facility	2.1	-	-	2.1	2.1	-	-	2.1	-	0%	-	0%
38	56815	Paintearth Wind Project	0.6	0.1	-	0.7	0.6	-	-	0.6	0.1	100%	-	0%
39	56820	Halkirk II Wind Power Facility	0.8	-	-	0.8	0.8	-	-	0.8	-	0%	-	0%
40	56865	Mainstream Wainwright	0.2	-	-	0.2	0.2	-	-	0.2	-	0%	-	0%
41	56878	SAGD Foster Creek DTS Cap Upgrade	0.2	-	-	0.2	0.2	-	-	0.2	-	0%	-	0%
42	58145	Red Deer Battery Energy Storage System	0.4	-	-	0.4	0.1	0.3	-	0.4	(0.3)	-100%	-	0%
43	58180	Spirit River POD Substation	-	(1.1)	(1.1)	-	-	4.2	4.2	-	(5.3)	-100%	(5.3)	-100%
44	58181	Simonette 733S Substation Capacity Upgrade	-	-	-	-	-	(0.6)	(0.6)	-	0.6	-100%	0.6	-100%
45	58204	Battery Storage	0.1	-	-	0.1	0.1	-	-	0.1	-	0%	-	0%
46	58215	Sharp Hills Windfarm	0.6	12.3	-	12.9	0.6	-	-	0.6	12.3	100%	-	0%
47	58225	TransAlta Garden Plain Wind	0.3	-	-	0.3	-	0.3	-	0.3	(0.3)	-100%	-	0%
48	58474	Lanfine South Wind	-	0.0	-	0.0	-	-	-	-	0.0	100%	-	0%
49	58525	Oyen Wind Energy Project	0.1	-	-	0.1	0.1	-	-	0.1	-	0%	-	0%
50	58526	Oyen Wind Power Project	1.4	(0.7)	-	0.7	0.1	1.3	-	1.4	(2.0)	-100%	-	0%

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL CONTRIBUTIONS
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

			2018 Actual				2017 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Prior Year	Var. %	Higher/(Lower) Additions Actual to Prior Year	Var. %
51	58562	Hand Hills Wind Power Facility	0.7	-	-	0.7	0.7	-	-	0.7	-	0%	-	0%
52	58569	Hand Hills Wind Power Facility	0.5	-	-	0.5	0.5	0.0	-	0.5	(0.0)	-100%	-	0%
53	58572	Suncor Hand Hills Wind Project Phase 2	0.2	-	-	0.2	-	0.2	-	0.2	(0.2)	-100%	-	0%
54	58573	Suncor Hand Hills Solar	0.2	-	-	0.2	-	0.2	-	0.2	(0.2)	-100%	-	0%
55	58574	Forestberg Area Solar	-	0.1	-	0.1	-	-	-	-	0.1	100%	-	0%
56	58578	EDF EN Hand Hills WAGF	0.1	-	-	0.1	-	0.1	-	0.1	(0.1)	-100%	-	0%
57	58579	EDF EN Berry Creek WAGF	(0.0)	-	-	(0.0)	-	(0.0)	-	(0.0)	0.0	-100%	-	0%
58	58650	#1824-Spirit Pine-Lone Pine WAGF	0.0	-	-	0.0	-	0.0	-	0.0	(0.0)	-100%	-	0%
59	58843	Wheatland Wind New POS	0.5	-	-	0.5	0.4	0.2	-	0.5	(0.2)	-100%	-	0%
60	58844	Echo Wind Power New POS	1.2	-	-	1.2	0.1	1.1	-	1.2	(1.1)	-100%	-	0%
61	58902	Monitor Substation Capacity Upgrade	-	-	-	-	-	-	-	-	-	0%	-	0%
62	58922	Eyre 558S Substation Interconnection	0.1	-	-	0.1	0.1	-	-	0.1	-	0%	-	0%
63	58925	Cavendish Substation	1.0	-	-	1.0	1.0	-	-	1.0	-	0%	-	0%
64	58970	Bohn 913S Substation Transformer Addition	-	(0.9)	(0.9)	-	3.0	(0.0)	3.0	-	(0.9)	100%	(3.9)	-100%
65	58971	Bauer 918S Substation Transformer Addition	-	-	-	-	-	(0.9)	(0.9)	-	0.9	-100%	0.9	-100%
66			31.1	19.8	2.5	48.4	33.5	10.4	12.8	31.1				
67	**OTHER TRANSMISSION**													
68	50010	50010 - Substation Capital Maintenance	0.8	(0.0)	(0.0)	0.8	0.6	0.2	0.0	0.8	(0.2)	-100%	(0.0)	-100%
69	50020	50020 - Lines Capital Maintenance	0.2	0.2	0.1	0.3	0.0	0.4	0.2	0.2	(0.2)	-48%	(0.1)	-63%
70	50130	Refurbish/Replace Engines and Turbines	(0.2)	(0.0)	(0.0)	(0.2)	-	(0.1)	0.1	(0.2)	0.1	-64%	(0.2)	-100%
71	50400	Telecommunication Capital Maintenance	-	-	-	-	-	0.0	0.0	-	(0.0)	-100%	(0.0)	-100%
72	50455	Replacement of End of Life Radios	(0.1)	-	-	(0.1)	-	0.0	0.1	(0.1)	(0.0)	-100%	(0.1)	-100%
73	90130	Refurbish/Replace Engines and Turbines	0.2	(0.2)	-	-	-	0.2	-	0.2	(0.3)	-100%	-	0%
74			0.8	0.0	0.0	0.8	0.6	0.7	0.4	0.8				
75														
76			31.9	19.8	2.5	49.2	34.1	11.0	13.2	31.9				

ATCO Electric Transmission (AET)

VARIANCE EXPLANATIONS OF CAPITAL EXPENDITURES

FOR THE YEAR ENDED DECEMBER 31, 2018

($Millions)

Line No.	Project	Description	2018 Actual Expend	2017 Actual Expend	Variance Actual to Prior Year	Var %	Variance Explanation
1	**CAPITAL MAINTENANCE**		79.6	65.5	14.1	22%	2018 expenditures are higher than 2017 due mainly to an increase in scope for the substation maintenance and replace major apparatus program and the completion of three substation rebuilds.
2							
3	**TELECOMMUNICATION**		16.3	24.2	(7.9)	-33%	2018 expenditures are lower than 2017 due mainly to additional scope in 2017 related to Grande Prairie Area Telecom Reliability construction activities and material procurement for the mobile radio expansion program occurring in 2017.
4							
5	**SCADA/EMS**		4.0	1.2	2.8	241%	2018 expenditures are higher than 2017 due mainly to the execution of the EOP-008-AB-1 project in 2018.
6							
7	**DIRECT ASSIGNED PROJECTS - SYSTEM**		120.4	66.9	53.5	80%	2018 expenditures are higher than 2017 due mainly to the construction activities for the Fort McMurrary 240 kV Development project and Jasper Transmission interconnection project; In addition, line construction contract close out costs incurred for the EATL project were higher in 2018 than in 2017.
8							
9	**DIRECT ASSIGNED PROJECTS - CUSTOMER**		15.4	37.8	(22.4)	-59%	2018 expenditures are lower than 2017 due mainly to the completion of Eureka River 861S Xmer addition and Spirit River POD Substation in 2017 and the majority of construction activities for MUIR POD occurring in 2017.
10							
11	**TRANSMISSION ISOLATED GENERATION**		3.0	10.1	(7.1)	-70%	2018 expenditures are lower than 2017 due mainly to a reduction in scope for isolated operation activities and the Garden River Interconnection project was completed in 2017.
12							
13	**TOTAL TRANSMISSION**		**238.8**	**205.7**			
14							
15	**DIRECT GENERAL PP&E**		(0.2)	3.8	(4.0)	-105%	2018 expenditures are lower than 2017 due to the sale of end-of-life and surplus fleet; and reduced need in 2018 for new toolsets due to workforce reductions.
16							
17	**SOFTWARE**		8.9	15.8	(6.9)	-44%	2018 expenditures are lower than 2017 due mainly to lower activity in 2018 as compared to 2017.
18							
19	**BUILDINGS**		2.3	0.5	1.8	338%	2018 expenditures are higher than 2017 due mainly to capital improvements and enhancements on leased
20							
21	**TOTAL DIRECT GENERAL PP&E**		**11.0**	**20.1**			
22							
23	**CAPITAL EXPENDITURES**		**249.8**	**225.8**			

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CAPITAL ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Project	Description	2018 Actual Adds	2017 Actual Adds	Variance Actual to Prior Year	Var %	Variance Explanation
1	**CAPITAL MAINTENANCE**		72.7	84.9	(12.3)	-14%	2018 additions are lower than 2017 due mainly to the procurement of emergency apparatus equipment in 2017 and project schedule adjustments to optimize resource utilization for the Replace or Rebuild Major Apparatus program.
2							
3	**TELECOMMUNICATION**		14.6	28.6	(14.0)	-49%	2018 additions are lower than 2017 due mainly to the completion of the Grande Prairie Area Telecom Reliability project and MPLS Phase 4 in 2017.
4							
5	**SCADA / EMS**		4.0	2.6	1.4	55%	2018 additions are higher than 2017 due mainly to the completion of the EOP-008-AB-1 project in 2018.
6							
7	**DIRECT ASSIGNED PROJECTS - SYSTEM**		129.6	11.2	118.4	1053%	2018 additions are higher than 2017 addition mainly due to energization of the Fort McMurray 240 kV Development project in 2018.
8							
9	**DIRECT ASSIGNED PROJECTS - CUSTOMER**		21.6	28.2	(6.6)	-23%	2018 additions are lower than 2017 due to less volume of customer projects being put into service in 2018 as compared to 2017.
10							
11	**TRANSMISSION ISOLATED GENERATION**		3.2	7.8	(4.5)	-58%	2018 additions are lower than 2017 due mainly to the completion of the Garden River Interconnection project in 2017.
12							
13	**Sub Total**		**245.7**	**163.4**			
14	Net Salvage		(5.4)	(7.9)			
15	**Total Transmission**		**240.3**	**155.5**			
16							
17	**DIRECT GENERAL PP&E**		(0.2)	3.8	(4.0)	-104%	2018 additions are lower than 2017 due to the sale of end-of-life and surplus fleet; and reduced need in 2018 for new toolsets due to workforce reductions.
18							
19	**SOFTWARE**		13.9	9.2	4.7	51%	2018 additions are higher than 2017 due mainly to the implementation of the Oracle and Hyperion enterprise planning programs.
20							
21	**BUILDINGS**		2.7	0.1	2.7	3595%	2018 additions are higher than 2017 due mainly to capital improvements and enhancements on leased space.
22							
23	**Sub Total**		**16.5**	**13.1**			
24	Net Salvage		**2.2**	**1.0**			
25	**Total Direct General PP&E**		**18.6**	**14.1**			
26							
27	**Capital Additions**		**258.9**	**169.6**			

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CONTRIBUTION EXPENDITURES
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Project	Description	2018 Actual Expend	2017 Actual Expend	Variance Actual to Prior Year	Var %	Variance Explanation
1		**DIRECT ASSIGNED PROJECTS**	19.8	10.4	9.4	91%	2018 contribution expenditures are higher than 2017 due mainly to the timing of contributions in 2018 to cover the Sharp Hills Windfarm project.
2							
3		**Contribution Expenditures**	**19.8**	**10.4**			

ATCO Electric Transmission (AET)

VARIANCE EXPLANATIONS OF CONTRIBUTION ADDITIONS

FOR THE YEAR ENDED DECEMBER 31, 2018

($Millions)

Line No.	Project	Description	2018 Actual Adds	2017 Actual Adds	Variance Actual to Prior Year	Var %	Variance Explanation
1		**DIRECT ASSIGNED PROJECTS**	2.5	12.8	(10.4)	-81%	2018 contribution additions are lower than 2017 due mainly to the lower volume and magnitude of customer projects that went into service in 2018 compared to 2017.
2							
3		**Contribution Additions**	**2.5**	**12.8**			

ATCO Electric Transmission (AET)
SUMMARY OF UTILITY INCOME TAX
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Description	Cross-Reference	2018 Actual	2018 Approved*	2017 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Current Tax							
2	Federal Income Tax							
3	Federal Taxable Income		(12.3)	-	7.6	(19.9)	-260.7%	
4	Income Tax Rate		15%	-	15%	-	0.0%	
5	**Total Federal Income Tax**		**(1.8)**	**-**	**1.1**	**(3.0)**	**-260.7%**	
6								
7	Provincial Income Tax							
8	Federal Taxable Income		(12.3)	-	7.6	(19.9)	-260.7%	
9	Add: CCA Federal Flowthrough		316.1	-	324.9	(8.8)	-2.7%	
10	Less: CCA Provincial Flowthrough		316.1	-	324.8	(8.8)	-2.7%	
11	Provincial Taxable Income		(12.3)	-	7.7	(20.0)	-259.8%	
12	Income Tax Rate		12%	-	12%	-	0.0%	
13	**Provincial Income Tax**		**(1.5)**	**-**	**0.9**	**(2.4)**	**-259.8%**	
14	Prior Year Adjustment		(3.2)	-	(0.4)	(2.8)	100.0%	
15	**Total Current Tax**		**(6.5)**	**-**	**1.7**	**(8.1)**	**-489.1%**	
16								
17	Future Tax							
18	Temporary Differences		198.7	-	230.5	(31.8)	-13.8%	
19	Income Tax Rate		15%	-	15%	-	0.0%	
20			29.8	-	34.6	(4.8)	-13.8%	
21	**Total Future Tax**		**29.8**	**-**	**34.6**	**(4.8)**	**-13.8%**	
22								
23	Other Items							
24	Preferred Dividend Tax		1.5	-	1.4	0.1	3.6%	
25	**Total Other Items**		**1.5**	**-**	**1.4**	**0.1**	**3.6%**	
26								
27	**Transmission Income Tax**		**24.8**	**-**	**37.6**	**(12.9)**	**-34.2%**	
28								
29	Farms, Irrigation Transmission							
30	Utility Income Tax Expense		0.3		0.5	(0.2)	-36.4%	
31								
32	**Total Transmission Income Tax**	Sch 1.0-T	**25.1**	**-**	**38.1**	**(13.0)**	**-34.2%**	**Note 1**

33
34 **Note 1** 2018 Actuals are lower than 2017 Actuals by $13.0 mainly due to lower Utility earnings.
35
36 In accordance with Commission Direction 2 in Decision 22570-D01-2018, the unfunded FIT liability is $418.1 for 2018 and $386.4 for 2017,
37 the year-over-year change being $31.8.
38
39 ***** In accordance with the guidance provided under Section 4.3.3 for AUC Rule 005, whereby interim rates are in place pending a final decision by
40 the AUC, AET has provided a comparison of its 2018 Actuals against its prior year actuals.

ATCO Electric Transmission (AET)
ANALYSIS OF AFFILIATE COST OF GOODS SOLD
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Service	Cross-Reference	Affiliate	2018 Actual Amount	2017 Actual Amount	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	**Transmission Affiliate Cost of Goods Sold**							
2	Operations & Maintenance		Alberta PowerLine	14.1	18.1	(4.0)	-22.3%	
3	Operations & Maintenance		ATCO Power Canada Ltd.	9.3	7.6	1.7	22.1%	
4	Operations and Metering Services		ATCO Energy Services Ltd.	0.2	0.4	(0.2)	-45.0%	
5	Operations & Maintenance		Northland Utilities (NWT) Limited	0.0	0.0	0.0	223.4%	
6	Operations & Maintenance		Yukon Electrical Company Limited	0.0	0.0	0.0	22.9%	
7	Operations & Maintenance		ATCO Electric Distribution	-	-	-	100.0%	
8	Operations & Maintenance		Northland Utilities (Yellowknife) Limited	0.1	0.0	0.0	20.2%	
9	Operations & Maintenance		ATCO Structures and Logistics	-	0.6	(0.6)	-100.0%	
10	Other items individually less than $0.1			0.4	0.3	0.1	41.5%	
11								
12	**Isolated Generation Affiliate Cost of Goods Sold**							
13	Operations & Maintenance		ATCO Electric Distribution	-	-	-	100.0%	
14	Other items individually less than $0.1			-	0.0	(0.0)	-100.0%	
15								
16	**Total Affiliate Cost of Goods Sold**			**24.1**	**27.0**	**(2.9)**	-10.9%	

ATCO Electric Transmission (AET)
ANALYSIS OF AFFILIATE COST OF GOODS SOLD (CORPORATE)
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Nature of Service	Affiliate	Cross-Ref.	2018 Actual Amount	2017 Actual Amount	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	**Corporate Affiliate Cost of Goods Sold**							
2	Administrative Services	Alberta PowerLine		0.6	1.7	(1.1)	-64.9%	
3	Administrative Services	Northland Utilities (NWT) Limited		0.1	0.1	0.0	4.0%	
4	Administrative Services	Yukon Electrical Company Limited		0.1	0.2	(0.1)	-56.9%	
5	Administrative Services	Northland Utilities (Yellowknife) Limited		0.1	0.1	(0.1)	-43.5%	
6								
7	**Total Affiliate Cost of Goods Sold**			**0.9**	**2.2**	**(1.3)**	-60.4%	

ATCO Electric Transmission (AET)
SUMMARY OF PAYROLL AND MANPOWER STATISTICS
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

SALARIES, WAGES AND EMPLOYEE BENEFITS

Line No.	Description	Cross-Reference	2018 Actual	2018 Approved*	2017 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
	Salaries, Wages and Employee Benefits							
1	Transmission Operations		32.0	-	28.5	3.5	12.4%	
2	Transmission Capital		49.3	-	59.9	(10.6)	-17.6%	
3	Transmission Corporate - Operations		9.1	-	11.1	(2.0)	-17.7%	
4	Transmission Corporate - Capital		7.6	-	10.7	(3.1)	-28.7%	
5								
6	**Salaries, Wages and Employee Benefits Charged to Utility Operations**		98.1	-	110.2	(12.1)	-11.0%	

EMPLOYEE ALLOCATION

Line No.	Description	Cross-Reference	2018 Actual	2018 Approved	2017 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
	Manpower Statistics							
7	Total Regular Employees (FTEs)		695.4	-	784.8	(89.4)	-11.4%	
8	Total Temporary Employees (FTEs)		20.9	-	16.1	4.9	30.2%	
9	**Total Manpower**		716.3	-	800.9	(84.5)	-10.6%	**Note 1**
10	Less:							
11	Allocated to Non-regulated		0.3	-	1.0			
12	**Total Manpower - Utility Operations**		716.1	-	799.9			
13								
14	**Note 1** 2017 FTEs have been revised to incorporate the corrections for errors that are identified in Exhibit 22742-X0490.01.							

***** In accordance with the guidance provided under Section 4.3.3 for AUC Rule 005, whereby interim rates are in place pending a final decision by the AUC, AET has provided a comparison of its 2018 Actuals against its prior year actuals.

ATCO Electric Transmission (AET)
SUMMARY OF RESERVE/DEFERRAL ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 2018
($Millions)

Line No.	Description	Cross-Ref.	2018 Actual Opening Balance	2018 Actual Adds	2018 Actual Provision	2018 Actual Adjustments	2018 Actual Ending Balance	2017 Actual Opening Balance	2017 Actual Adds	2017 Actual Provision	2017 Actual Adjustments	2017 Actual Ending Balance
1	List of Reserve/Deferral Accounts											
2												
3	Reserve for Injuries and Damages		0.9	(0.2)	(0.0)	-	0.7	0.8	(0.5)	0.7	-	0.9
4	Variable Pay Program (VPP)		5.8	(2.9)	2.3	-	5.2	4.6	(3.8)	5.0	-	5.8
5	Vegetation Management		0.0	(10.9)	10.9	-	0.0	(0.9)	(6.7)	7.6	-	0.0
6												
7	**Total Deferred Assets**		6.8	(14.0)	13.2	-	6.0	4.6	(11.0)	13.2	-	6.8
8												
9	Federal Future Income Tax		147.1	13.9	29.8	-	190.8	120.3	-	26.7	-	147.1
10												
11	**Total Deferred Liabilities**		147.1	13.9	29.8	-	190.8	120.3	-	26.7	-	147.1

ATCO Electric Transmission (AET)
Summary of Pension Plan Contributions
For the Year Ended December 31, 2018
($Millions)

ATCO Electric has provided the following information below in response to Direction 13 from AUC Decision 2010-189 which indicated:

The Commission would also like to establish the ability to monitor contributions into the Pension Plan. In this regard the Commission directs ATCO Utilities in its respective annual Rule 005: Annual Reporting Requirements of Operational and Financial Results (Rule 005) filings to include the following information:

i) The amounts contributed to the Pension Plan on a calendar year basis by each of the ATCO Utilities (broken down by utility) and the amounts contributed by the unregulated companies participating in the Pension Plan collectively. In reporting these contributions, the report should separately identify, amounts contributed as service costs under each of the DB Plan and the DC Plan and amounts contributed in respect of the DB Plan unfunded liability.

<u>2018 Actual</u>

	Defined Benefit Pension Expense		Defined Contribution Pension Expense	**Total**
	Service Amount	Special Payment	Service Amount	
ATCO Electric (Note 1)	2.9	-	4.4	**7.3**
ATCO Other	3.6	-	5.2	**8.8**

<u>2018 Forecast (per AET 2018-2019 GTA)</u>

	Defined Benefit Pension Expense		Defined Contribution Pension Expense	**Total**
	Service Amount	Special Payment	Service Amount	
ATCO Electric (Note 2)	3.2	-	Note 4	**3.2**
ATCO Other (Note 3)	4.8	-	Note 4	**4.8**

Note 1 - The actual defined benefit and defined contribution service amounts along with the special payment do not include amounts that are allocated from the ATCO Head office. This amount includes COLA at 100%
Note 2 - ATCO Electric's portion of the estimated employer's current service cost as per the Mercer report as at Dec 31, 2017 filed in the AET 2018-2019 GTA, Exhibit 22742-X0572.02(CL), AET Information Responses Round 3 to CCA Part 3 of 3, PDF Page 171.
Note 3 - ATCO Other's portion of the estimated employer's current service cost as per the Mercer report as at Dec 31, 2017 filed in the AET 2018-2019 GTA, Exhibit 22742-X0572.02(CL), AET Information Responses Round 3 to CCA Part 3 of 3, PDF Page 171.
Note 4 - Not available given pension common matters application only addresses DB plan.

ii) A reconciliation in respect of the previous calendar year, by utility, of amounts collected through rates in respect of pension funding obligations with amounts contributed to the pension plan including amounts in the deferral account approved in accordance with this Decision.

<u>2017 Reconciliation (ATCO Electric - Transmission):</u>

2017 Special Payment Pension costs included in ATCO Electric Transmission's Revenue Requirement (Note 5)	-
2017 Actual Special Payment Pension contributions (Note 6)	-
2017 Actual Special Payment Pension contributions - allocated from ATCO Head Office (Note 6)	-
Refund/(collection) to / (from) customers	-

Note 5 - Per ATCO Electric Transmission 2015-2017 GTA Second Compliance Filing (Exhibit 22860-X0005, Schedule 3, L.7)
Note 6 - Per ATCO Utilities Pension Application, Proceeding ID 21831, Exhibit 0006, Appendix 3

Accordingly the deferral account should be calculated as the annual difference between the amounts collected in rates in respect of the special payments and the special payment amounts actually paid by ATCO Utilities pursuant to the Pension Valuation(s) accepted by the Superintendent of Pensions that were in force during such year.

<u>2018 Reconciliation (ATCO Electric - Transmission):</u>

2018 Special Payment Pension costs included in ATCO Electric Transmission's Revenue Requirement (Note 7)	-
2018 Actual Special Payment Pension contributions (Note 8)	-
2018 Actual Special Payment Pension contributions - allocated from ATCO Head Office (Note 8)	-
Refund/(collection) to / (from) customers	-

Note 7 - Per ATCO Electric Transmission 2018-2019 GTA (Exhibit 22742-X0003, Schedule 3, L.6)
Note 8 - Per ATCO Utilities Pension Application, Proceeding ID 21831, Exhibit 0006, Appendix 3

iii) Confirmation of the date of any actuarial valuation reports filed with the Superintendent of Pensions since the last Rule 005 filing, and the associated impact of any filings on the pension funding requirements of each of the ATCO Utilities.

The Mercer 2017 CU Pension Plan Report was filed with the Superintendent of Pensions in July 13, 2018. The required pension funding contributions for ATCO Electric Transmission beginning January 1, 2018 are $3.2 million for current service and $0.0 million for special payments.

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS (TRANSMISSION & DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2018
INCOME STATEMENT ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
			(see attached)					
1	**Revenues**		**1,190.1**	**(429.6)**	**924.5**	**695.3**		
2								
3	Impact of AUC Decisions						51.9	
4	Eliminate Non-Utility Revenues						(31.5)	
5	Reclassification of Revenue Offsets						(29.2)	
6	Reclass of Amortization of Contributions to Depreciation						(10.1)	
7	Non IFRS Deferral Revenue						(3.5)	
8	Other (prior period Decisions and Adjustments)						(2.5)	
9								
10		Sch 1	1,190.1	(429.6)	924.5	695.3	(24.9)	670.3
11								
12	**Cost of Sales**		**-**	**(412.3)**	**412.3**	**-**		
13								
14								
15								
16			-	(412.3)	412.3	-	-	-
17								
18	**Fuel**		**7.1**	**-**	**-**	**7.1**		
19								
20	Reclassification of Carbon Tax from O&M						0.4	
21								
22		Sch 1	7.1	-	-	7.1	0.4	7.5
23								
24								
25	**Operating and Maintenance**		**375.3**	**(10.5)**	**193.3**	**192.5**		
26								
27	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						(3.8)	
28	Non-recovered (disallowed) Utility Costs						(7.0)	
29	Farms Reclassification						(3.7)	
30	Other						(3.1)	
31	RID and Rate Case - Adjustment to Provision						(0.8)	
32	Reclassification of Credit Facility fees from Financing						0.9	
33	Elimination of Non-Regulated Costs						(0.5)	
34	Reclassification of Carbon Tax from O&M						(0.4)	
35								
36								
37		Sch 1	375.3	(10.5)	193.3	192.5	(18.3)	174.2
38								

ATCO Electric Transmission (AET)
RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS (TRANSMISSION & DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2018
INCOME STATEMENT ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
39	**Depreciation and Amortization**		**302.9**	**(8.0)**	**140.2**	**170.8**		
40								
41	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						34.0	
42	Reclass of Amortization of Contributions to Depreciation						(10.1)	
43	Farms Reclassification						1.7	
44	Non-Utility Depreciation						(1.8)	
45	Other						(1.4)	
46								
47		Sch 1	302.9	(8.0)	140.2	170.8	22.3	193.0
48								
49	**Income Tax**		**77.6**	**0.3**	**28.7**	**48.6**		
50	Tax on Adjustments	Note 2					(23.5)	
51		Sch 1	77.6	0.3	28.7	48.6	(23.5)	25.1
52								
53	**Revenue Offsets**							
54								
55	Reclassification of Revenue Offsets						(23.5)	
56								
57		Sch 1	-	-	-	-	(23.5)	(23.5)
58								
59	**Return**		427.2	0.9	150.0	276.3		
60	Adjustments	Note 1					23.3	
61		Sch 1	427.2	0.9	150.0	276.3	23.3	299.7
62								
63	**Note 1 - Return Adjustments**							
64	Long Term Debt & Other		**211.8**	**-**	**65.9**	**146.0**		
65	Adjustment for IFRS IDC Treatment						(4.2)	
66	Financing Other						3.7	
67	Credit facility Reclass to O&M						(0.9)	
68			211.8	-	65.9	146.0	(1.4)	144.6
69								
70	Preferred Shares		**-**	**-**	**-**	**-**		
71							3.4	
72			-	-	-	-	3.4	3.4
73								
74	Return on Equity		215.4	0.9	84.1	130.4		
75		Note 2					21.3	
76			215.4	0.9	84.1	130.4	21.3	151.7
77								
78	Total Return Adjustments		427.2	0.9	150.0	276.3	23.4	299.7
79								

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS (TRANSMISSION & DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2018
INCOME STATEMENT ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
80							**(Return)**	
81	**Note 2 - Return on Equity Adjustments**					Before tax	After tax	Tax impact
82								
83	**Financing & Subs**							
84	Interest and Other					(2.7)	(2.0)	(0.7)
85	Preferred Dividends					(3.4)	(3.4)	-
86	AFUDC vs IDC					4.2	3.0	1.1
87								
88	**Income Tax**							
89	Income Tax (Provincial Future Tax for IFRS)						20.6	(20.6)
90	Income Tax (T2S1 Additions & Deductions Non Regulatory)						4.6	(4.6)
91	Income Tax (T2S1 Additions & Deductions Non IFRS)						(2.6)	2.6
92	Income Tax (T2S1 Other)						1.3	(1.3)
93								
94	**Other Income Statement Items**							
95	Revenue Tax Impact					4.4	3.2	1.2
96	O&M Tax Impact					(17.8)	13.0	4.8
97	Depreciation Tax Impact					22.3	(16.2)	(6.0)
98								
99						6.8	21.4	(23.5)

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(Transmission and Distribution)

FOR THE YEAR ENDED DECEMBER 31, 2018
BALANCE SHEET ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements (see attached)	Adjustments	Total
1	**Assets**				
2	**Current Assets**				
3	Cash and short term investments		24.5	-	24.5
5	Accounts receivable		173.7	-	173.7
6	Income taxes		1.0	828.9	829.9
7	Inventories		2.5	-	2.5
8	Prepaid expenses		6.9	-	6.9
10					
11	**Property, plant and equipment**		9,341.5	(1,663.3)	7,678.2
12	**Intangibles**		325.3	(0.1)	325.2
13					
14	**Investments**		117.0	(117.0)	(0.0)
15			-	-	
16	**Regulatory Assets**		-	87.1	87.1
17	**Deferred financing Charges**		-	27.6	27.6
18	**Other**		-	-	-
19					
20	**Total Assets**		**9,992.4**	**(836.9)**	**9,155.5**
21					
22					
23	**Liabilities**				
24	**Current Liabilities**				
25	Bank Indebtedness		0.2	-	0.2
26	Short term advances from parent and affiliated corporations		54.3	-	54.3
27	Accounts payable and accrued liabilities		115.7	-	115.7
28	Owing to parent and affiliated corporations		76.2	-	76.2
29	Income taxes payable		0.2	0.0	0.2
30	Regulatory Liabilities		-	-	-
31	Long term debt		132.0	(132.0)	-
32					
33	**Future income taxes**		858.7	84.6	943.3
34	**Regulatory Liabilities**		-	-	-
35	**Long term debt**		4,876.2	10.9	4,887.1
36	**Other**		1,044.0	(989.2)	54.8
37					
38	**Total Liabilities**		**7,157.5**	**(1,025.7)**	**6,131.9**
39					
40	**Equity**				
41	Equity preferred shares to Parent Corporation		142.0	-	142.0
42					
43	**Class A and Class B shares owner's equity**				
44	Class A and Class B shares		1,212.4	-	1,212.4
45	Retained earnings		1,480.5	188.7	1,669.2
46	Non-controlling interest		-	-	-
47	**Total Equity**		**2,834.9**	**188.7**	**3,023.6**
48					
49	**Total Liabilities and Share Owner's Equity**		**9,992.4**	**(836.9)**	**9,155.5**

ATCO ELECTRIC LTD.

NON-CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2018

Independent auditor's report

To the Shareowner of ATCO Electric Ltd.

Our opinion

In our opinion, the accompanying non-consolidated financial statements present fairly, in all material respects, the financial position of ATCO Electric Ltd. (the Company) as at December 31, 2018 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited
The Company's non-consolidated financial statements comprise:

- the non-consolidated statement of earnings for the year ended December 31, 2018;
- the non-consolidated statement of comprehensive income for the year ended December 31, 2018;
- the non-consolidated balance sheet as at December 31, 2018;
- the non-consolidated statement of changes in equity for the year ended December 31, 2018;
- the non-consolidated statement of cash flow for the year ended December 31, 2018; and
- the notes to the non-consolidated financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the non-consolidated financial statements* section of our report.

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

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the non-consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
Stantec Tower, 10220 103 Avenue NW, Suite 2200, Edmonton, Alberta, Canada T5J 0K4
T: +1 780 441 6700, F: +1 780 441 6776

Responsibilities of management and those charged with governance for the non-consolidated financial statements

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

In preparing the non-consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the non-consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the non-consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these non-consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the non-consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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 Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern.

If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the non-consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the non-consolidated financial statements, including the disclosures, and whether the non-consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Edmonton, Alberta
April 30, 2019

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NON-CONSOLIDATED STATEMENT OF EARNINGS

(thousands of Canadian Dollars)	Note	Year Ended December 31 2018	2017
Revenues	5	**1,190,131**	1,148,715
Costs and expenses			
Salaries, wages and benefits		**(113,023)**	(107,921)
Plant and equipment maintenance		**(61,618)**	(60,787)
Fuel costs		**(7,093)**	(8,148)
Depreciation and amortization	9,10	**(302,944)**	(292,893)
Franchise fees		**(22,501)**	(20,950)
Property and other taxes		**(54,027)**	(54,404)
Other	6	**(124,086)**	(110,080)
		(685,292)	(655,183)
Dividend income from subsidiary companies	11	**7,038**	6,820
Operating profit		**511,877**	500,352
Interest income		**6,400**	7,332
Interest expense	7	**(225,277)**	(226,885)
Net finance costs		**(218,877)**	(219,553)
Earnings before income taxes		**293,000**	280,799
Income taxes	8	**(77,601)**	(74,461)
Earnings for the year		**215,399**	206,338

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

		Year Ended December 31	
(thousands of Canadian Dollars)	**Note**	**2018**	**2017**
Earnings for the year		**215,399**	206,338
Other comprehensive income (loss), net of income taxes			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits (1)	13	**1,562**	(1,218)
Comprehensive income for the year		**216,961**	205,120

(1) Net of income taxes of $(0.6) million for the year ended December 31, 2018 (2017 - $0.5 million).

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED BALANCE SHEET

(thousands of Canadian Dollars)	Note	December 31 2018	2017
ASSETS			
Current assets			
Cash		**10,916**	17,929
Short-term advances to parent company	24	**1,300**	1,272
Accounts receivable and contract assets	14	**154,041**	120,742
Accounts receivable from parent and affiliate companies	14, 24	**19,642**	34,801
Inventories		**2,548**	2,480
Income taxes recoverable		**996**	1,025
Prepaid expenses and other current assets		**6,888**	10,601
Advances to subsidiary companies	24	**12,250**	–
		208,581	188,850
Non-current assets			
Property, plant and equipment	9	**9,341,506**	9,195,705
Intangibles	10	**325,311**	320,103
Investment in subsidiary companies	11	**16,335**	16,335
Long-term advances to subsidiary companies	24	**91,413**	101,063
Other assets		**9,249**	10,680
Total assets		**9,992,395**	9,832,736
LIABILITIES			
Current liabilities			
Bank indebtedness		**178**	5,048
Short-term advances from parent and affiliated companies	24	**54,300**	34,772
Accounts payable and accrued liabilities		**115,700**	121,138
Accounts payable to parent and affiliate companies	24	**68,244**	90,471
Other provisions		**7,933**	2,612
Long-term debt	12	**132,044**	–
Other current liabilities		**232**	182
		378,631	254,223
Non-current liabilities			
Deferred income tax liabilities	8	**858,651**	782,722
Retirement benefit obligations	13	**56,348**	57,531
Deferred revenues	14	**987,661**	983,018
Long-term debt	12	**4,876,233**	4,871,632
Other liabilities		**–**	8
Total liabilities		**7,157,524**	6,949,134
EQUITY			
Equity preferred shares	15	**141,968**	141,968
Class A and Class B share owner's equity			
Class A and Class B shares	16	**1,212,428**	1,212,428
Retained earnings		**1,480,475**	1,529,206
		2,692,903	2,741,634
Total equity		**2,834,871**	2,883,602
Total liabilities and equity		**9,992,395**	9,832,736

See accompanying Notes to Non-consolidated Financial Statements.

DIRECTOR

DIRECTOR

NON-CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(thousands of Canadian Dollars)	**Note**	**Class A and Class B Shares**	**Equity Preferred Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Income**	**Total Equity**
December 31, 2016		1,212,428	141,968	1,594,581	–	2,948,977
Earnings for the year		–	–	206,338	–	206,338
Other comprehensive loss		–	–	–	(1,218)	(1,218)
Losses on retirement benefits transferred to retained earnings	13	–	–	(1,218)	1,218	–
Dividends	15,16	–	–	(270,495)	–	(270,495)
December 31, 2017		1,212,428	141,968	1,529,206	–	2,883,602
Earnings for the year		**–**	**–**	**215,399**	**–**	**215,399**
Other comprehensive income		**–**	**–**	**–**	**1,562**	**1,562**
Gains on retirement benefits transferred to retained earnings	13	**–**	**–**	**1,562**	**(1,562)**	**–**
Dividends	15,16	**–**	**–**	**(265,692)**	**–**	**(265,692)**
December 31, 2018		**1,212,428**	**141,968**	**1,480,475**	**–**	**2,834,871**

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED STATEMENT OF CASH FLOW

(thousands of Canadian Dollars)	Note	Year Ended December 31 2018	2017
Operating activities			
Earnings for the year		**215,399**	206,338
Adjustments to reconcile earnings to cash flows from operating activities	17	**600,632**	580,780
Changes in non-cash working capital	17	**(18,740)**	1,370
Cash flows from operating activities		**797,291**	788,488
Investing activities			
Additions to property, plant and equipment		**(406,646)**	(373,314)
Proceeds on disposal of property, plant and equipment		**700**	58
Additions to intangibles	10	**(37,913)**	(43,958)
Changes in non-cash working capital	17	**(17,544)**	(15,016)
Other		**(221)**	3,782
Cash flows used in investing activities		**(461,624)**	(428,448)
Financing activities			
Issue of long-term debt	12	**134,150**	130,000
Repayment of long-term debt		**–**	(80,000)
Dividends paid on equity preferred shares		**(5,692)**	(5,495)
Dividends paid to Class A and Class B share owner		**(260,000)**	(265,000)
Interest paid		**(224,796)**	(224,817)
Other		**(972)**	(1,054)
Cash flows used in financing activities		**(357,310)**	(446,366)
Decrease in cash position		**(21,643)**	(86,326)
Beginning of year		**(20,619)**	65,707
End of year	17	**(42,262)**	(20,619)

See accompanying Notes to Non-consolidated Financial Statements.

NOTES TO NON-CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2018

(Tabular amounts in thousands of Canadian Dollars, except as otherwise noted)

1. THE COMPANY AND ITS OPERATIONS

ATCO Electric is engaged in the transmission and distribution of electric energy in the Province of Alberta. Its registered office and head office is at 19th Floor, 10035 -105 Street NW, Edmonton, Alberta, T5J 2V6. ATCO Electric is principally owned by CU Inc. which is controlled by Canadian Utilities Limited, which in turn is principally controlled by ATCO Ltd. and its controlling share owner, the Southern family.

In these non-consolidated financial statements, "the Company" means ATCO Electric Ltd.

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The non-consolidated financial statements are prepared according to International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

Pursuant to the Company's regulatory obligation to the Alberta Utilities Commission (AUC) and interested parties, the Company is obliged to provide detailed information relating solely to the electric utility and not relating to non-regulated subsidiaries, nor electric utilities regulated by other jurisdictions. The Company has, therefore, exercised the exemption from full consolidation of its investment in subsidiary companies available under IAS 27 *Separate Financial Statements*. As a result, the Company’s investment in subsidiary companies and joint arrangements are carried at the original cost and the earnings of the subsidiary companies are reflected in the determination of earnings of the Company only to the extent of dividends received from the subsidiaries. The Company's proportionate interest in balances and transactions of joint arrangements have been excluded from these non-consolidated financial statements. Consolidated financial statements of the Company’s immediate parent, CU Inc., that comply with IFRS are available for public use. CU Inc. is incorporated in Canada and its registered office is at 4th Floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4.

Management authorized these non-consolidated financial statements for issue on April 29, 2019.

BASIS OF MEASUREMENT

The non-consolidated financial statements are prepared on a historic cost basis, except for retirement benefit obligations and cash-settled share-based compensation liabilities which are carried at remeasured amounts or fair value. The Company's significant accounting policies are described in Note 25.

Certain comparative figures have been reclassified to conform to the current presentation.

FUNCTIONAL AND PRESENTATION CURRENCY

The non-consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

USE OF ESTIMATES AND JUDGMENTS

Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the non-consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Estimates and judgments are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively. The significant judgments, estimates and assumptions are described in Note 21.

3. CHANGE IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS CREDIT LOSSES

The Company adopted the final component of IFRS 9 *Financial Instruments, Impairments*, on January 1, 2018. This component includes a new expected credit loss model. The new model takes into account an expectation of future events by estimating credit losses based on an assessment of counterparty credit risk. The change results in earlier recognition of bad debt expense.

Impact of adoption of IFRS 9 on consolidated financial statements

To determine the amount of expected credit losses, the Company used default and recoverability probabilities. At January 1, 2018 the total credit loss provision was less than a million, which was determined based on third party average default and recoverability probabilities. There was no change in the credit loss provision recorded on adoption of IFRS 9.

REVENUE RECOGNITION

The Company adopted IFRS 15 *Revenue from Contracts with Customers* on January 1, 2018, using the full retrospective transition method. Under the full retrospective transition method, the comparative figures for 2017 in the Company's non-consolidated financial statements have been restated. Certain practical expedients have been applied.

See Note 25 for accounting policies on revenue recognition.

Practical expedients

Effective January 1, 2017, the IFRS 15 transition date, the Company elected to use the following practical expedients:

(i) Information on the remaining performance obligations that have an original expected duration of one year or less is not disclosed;

(ii) For periods presented before January 1, 2018, the IFRS 15 adoption date, the information regarding the amount of the transaction price allocated to the remaining performance obligations and an explanation of when the Company expects to recognize this amount as revenue, are not disclosed;

(iii) Costs to obtain or fulfill a contract with an amortization period of less than a year have been expensed as incurred;

(iv) Where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance to date, revenue is recognized in the amount to which the Company has a right to invoice. Such performance obligations include:

- Provision of continuous distribution of electricity service;
- Provision of transmission of electricity service.

IMPACT OF CHANGES IN ACCOUNTING POLICIES

As the Company has utilized the practical expedients noted above, there was no impact on the prior year consolidated statement of earnings, balance sheet, statement of changes in equity and statement of cash flow.

4. ADJUSTED EARNINGS

ADJUSTED EARNINGS

Adjusted earnings are earnings for the year after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares,
- one-time gains and losses,
- significant impairments, and

- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of segment earnings used by the Chief Operating Decision Maker (CODM) to assess segment performance and allocate resources. Other accounts in the non-consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the year ended December 31 is shown below.

	2018	2017
Adjusted earnings	**287,075**	329,133
Restructuring costs	**(25,015)**	–
Rate-regulated activities	**(52,353)**	(128,290)
Dividends on equity preferred shares	**5,692**	5,495
Earnings for the year	**215,399**	206,338

Restructuring and other costs

In the second quarter of 2018, the Company recorded restructuring and other costs of $25 million, after-tax, that were not in the normal course of business. These costs mainly relate to staff reductions and associated severance costs.

Rate-regulated activities

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the utilities recognize revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company's rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulators' decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

	Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1.	Additional revenues billed in current period	Future removal and site restoration costs.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
2.	Revenues to be billed in future periods	Deferred income taxes.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
3.	Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
4.	Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

At December 31, the significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	2018	2017
Additional revenues billed in current period		
Future removal and site restoration costs (1)	**34,809**	25,936
Revenues to be billed in future periods		
Deferred income taxes (2)	**(48,142)**	(56,288)
Regulatory decisions received	**2,034**	17,247
Settlement of decisions and other items (3)	**(41,054)**	(115,185)
	(52,353)	(128,290)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) Income taxes are billed to customers when paid by the Company.

(3) In 2018, the Company recorded a decrease in earnings of $38 million mainly related to a refund of deferral account balances relating to 2013 and 2014.

Regulatory decisions received

Under rate-regulated accounting, the Company recognizes earnings from a regulatory decision pertaining to current and prior periods when the decision is received. There were no significant regulatory decisions impacting adjusted earnings during 2018, the significant decisions during 2017 are provided below.

	Decision	Timing	Amount	Description
1.	2013-2014 Deferral Accounts Application	September 2017	(7,239)	The Alberta Utilities Commission (AUC) issued a decision on ATCO Electric Transmission's 2013 to 2014 Deferral Accounts Application. The Application included $824 million of capital expenditures for the 35 direct-assigned AESO projects that went into service in 2013 and 2014. While the decision approved the inclusion of the vast majority of the capital expenditures into rate base, it resulted in a decrease to adjusted earnings, which relates to years prior to 2017.
2.	ATCO Electric General Tariff Application (GTA) Compliance Filing	June 2017	(10,008)	The AUC issued a decision on ATCO Electric's Compliance Filing relating to its 2015 to 2017 General Tariff Application. The decision adjusted ATCO Electric's 2016 and 2017 forecast allocation of labour costs between operating and maintenance expense and capital.

5. REVENUES

The significant categories of revenues recognized during the year are as follows:

	2018	2017
Distribution revenue	**425,200**	368,020
Transmission revenue	**621,905**	628,744
Customer contributions *(Note 14)*	**29,579**	24,396
Franchise fees & property tax revenues	**29,177**	26,927
Other	**84,270**	100,628
	1,190,131	1,148,715

6. OTHER COSTS AND EXPENSES

Other costs and expenses comprise the following:

	2018	2017
Professional fees, services and contractors	**9,278**	5,962
Technology expenses	**22,161**	26,842
Insurance	**5,151**	4,715
Travel and meals	**1,942**	2,721
Office services and other costs	**661**	1,938
Head office fees	**42,904**	26,808
Rent	**5,065**	5,477
Licenses	**14,278**	22,234
Other	**22,646**	13,383
	124,086	110,080

7. INTEREST EXPENSE

Interest expense primarily arises from interest on long-term debentures. The components of interest expense are summarized below.

	2018	2017
Long-term debt	**230,271**	229,798
Amortization of deferred financing charges	**868**	762
Other	**4,411**	3,119
	235,550	233,679
Less: interest capitalized *(Note 9)*	**(10,273)**	(6,794)
	225,277	226,885

Borrowing costs capitalized to property, plant and equipment during 2018 were calculated by applying a weighted average interest rate of 4.68 per cent (2017 - 4.76 per cent).

8. INCOME TAXES

INCOME TAX EXPENSE

The components of income tax expense are summarized below.

	2018	2017
Current income tax expense		
Expenses for the year	**2,276**	2,211
Adjustment in respect of prior years	**(26)**	_
	2,250	2,211
Deferred income tax expense		
Reversal of temporary differences	**75,290**	72,250
Adjustment in respect of prior years	**61**	_
	75,351	72,250
	77,601	74,461

The reconciliation of statutory and effective income tax expense is as follows:

		2018		2017
Earnings before income taxes	**293,000**	**%**	280,799	%
Income taxes, at statutory rates	**79,110**	**27.0**	75,816	27.0
Dividend income	**(1,900)**	**(0.6)**	(1,841)	(0.6)
Part VI.I tax net of transfer benefit	**124**	_	121	_
Other	**267**	**0.1**	365	0.1
	77,601	**26.5**	74,461	26.5

DEFERRED INCOME TAXES

The changes in deferred income tax liabilities are as follows:

	Property, Plant and Equipment	Intangibles	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations and Other	Total
December 31, 2016	721,605	50,043	(73,725)	12,970	710,893
Charge (credit) to earnings	59,018	3,542	3,703	5,987	72,250
Charge to other comprehensive income	–	–	–	(450)	(450)
Other	–	–	–	29	29
December 31, 2017	780,623	53,585	(70,022)	18,536	782,722
Charge (credit) to earnings	**108,270**	**2,634**	**(4,723)**	**(30,830)**	**75,351**
Charge to other comprehensive income	**–**	**–**	**–**	**578**	**578**
December 31, 2018	**888,893**	**56,219**	**(74,745)**	**(11,716)**	**858,651**

The Company does not expect its deferred income tax liabilities to reverse within the next twelve months (2017 - nil).

At the end of 2018, the Company had $278 million of non-capital tax losses and credits which expire between 2034 and 2037. The Company recognized deferred income tax assets of $75 million of losses and credits that expire.

9. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission & Distribution	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost					
December 31, 2016	9,983,848	382,103	277,312	524,722	11,167,985
Additions	–	–	384,463	–	384,463
Transfers	298,489	33,496	(357,766)	25,781	–
Retirements and disposals	(32,112)	(8,949)	(14,806)	(11,096)	(66,963)
Transfer to affiliate companies	(2,506)	–	–	(1,770)	(4,276)
December 31, 2017	10,247,719	406,650	289,203	537,637	11,481,209
Additions	**2,101**	–	**421,864**	–	**423,965**
Transfers	**396,826**	**5,731**	**(418,153)**	**15,596**	–
Retirements and disposals	**(32,751)**	**(1,730)**	–	**(12,104)**	**(46,585)**
Transfer to affiliate companies	–	**1,365**	–	**(266)**	**1,099**
December 31, 2018	**10,613,895**	**412,016**	**292,914**	**540,863**	**11,859,688**
Accumulated depreciation					
December 31, 2016	1,837,808	57,597	–	190,798	2,086,203
Depreciation	219,961	13,265	–	21,238	254,464
Retirements and disposals	(33,979)	(8,712)	–	(11,096)	(53,787)
Transfer to affiliate companies	(647)	—	—	(729)	(1,376)
December 31, 2017	2,023,143	62,150	–	200,211	2,285,504
Depreciation	**234,358**	**11,759**	–	**29,429**	**275,546**
Retirements and disposals	**(29,599)**	**(1,042)**	–	**(12,089)**	**(42,730)**
Transfer to affiliate companies	–	–	–	**(138)**	**(138)**
December 31, 2018	**2,227,902**	**72,867**	–	**217,413**	**2,518,182**
Net book value					
December 31, 2017	8,224,576	344,500	289,203	337,426	9,195,705
December 31, 2018	**8,385,993**	**339,149**	**292,914**	**323,450**	**9,341,506**

The additions to property, plant and equipment included $10.3 million of interest capitalized during construction for the year ended December 31, 2018 (2017 - $6.8 million).

10. INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights. A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Computer Software	Land Rights	Total
Cost			
December 31, 2016	274,828	208,756	483,584
Additions	34,346	9,612	43,958
Disposals	(10,476)	(281)	(10,757)
December 31, 2017	298,698	218,087	516,785
Additions	**20,951**	**10,059**	**31,010**
Disposals	**(1,815)**	–	**(1,815)**
December 31, 2018	**317,834**	**228,146**	**545,980**
Accumulated amortization			
December 31, 2016	154,699	22,584	177,283
Amortization	26,707	3,449	30,156
Disposals	(10,476)	(281)	(10,757)
December 31, 2017	170,930	25,752	196,682
Amortization	**22,482**	**3,320**	**25,802**
Disposals	**(1,815)**	–	**(1,815)**
December 31, 2018	**191,597**	**29,072**	**220,669**
Net book value			
December 31, 2017	127,768	192,335	320,103
December 31, 2018	**126,237**	**199,074**	**325,311**

11. INVESTMENTS

The investment in subsidiary companies at December 31 is as follows:

Investee	Principal place of business	Percentage ownership	2018	2017
ATCO Electric Yukon	Whitehorse, Yukon	100%	**12,171**	12,171
Norven Holdings Inc.	Edmonton, Alberta	100%	**4,164**	4,164
			16,335	16,335

During 2018, the Company received $7.0 million in cash dividends from its subsidiaries (2017 - $6.8 million).

The Corporation has an 80% interest in ATCO-Valard Design Build Joint Venture. ATCO-Valard Design Build Joint Venture is an unincorporated joint arrangement between the Company and Valard Construction LP, a subsidiary of Quanta Services, Inc., for the purpose of developing, designing and building the Fort McMurray West 500-kilovolt (kV) Transmission Project.

12. LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	Effective Interest Rate	2018	2017
Debentures - unsecured	4.697% (2017 - 4.729%)	**5,030,931**	4,895,931
(interest is the average effective interest rate weighted by principal amounts outstanding)			
Other long-term obligation, due June 2020 - unsecured	3.950%	**4,900**	3,150
Less: deferred financing charges		**(27,554)**	(27,449)
		5,008,277	4,871,632
Less: amounts due within one year		**(132,044)**	–
		4,876,233	4,871,632

Debenture Issuances

During 2018, the Company issued $135.0 million of 3.95 per cent debentures maturing on November 23, 2048 (2017 - $130.0 million of 3.548 per cent debentures maturing on November 22, 2047).

13. RETIREMENT BENEFITS

The Company, together with Canadian Utilities Limited and its subsidiary companies, maintains registered defined benefit and defined contribution pension plans for most of its employees and non-funded defined benefit pension plans for certain officers and key employees. It also provides other post-employment benefits, principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan.

Information about the plans as a whole, in aggregate, can be found in the Canadian Utilities Limited consolidated financial statements for the year ended December 31, 2018.

Information about the Company's participation in the group benefit plans is as follows:

	2018		2017	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Defined benefit plans cost	**9,784**	**2,207**	14,280	2,144
Defined contribution plans cost	**9,601**	–	10,668	–
Total cost	**19,385**	**2,207**	24,948	2,144
Less: capitalized	**13,252**	**1,488**	16,972	1,451
Net cost recognized	**6,133**	**719**	7,976	693
Accrued benefit obligations				
Beginning of year	22,586	34,945	18,815	33,544
Defined benefit plan cost	**9,784**	**2,207**	14,280	2,144
Benefit payments	**(2,873)**	**(1,165)**	(2,742)	(1,120)
Contributions to defined benefit plans	**(6,995)**	–	(9,059)	–
Actuarial losses (gains)	**(627)**	**(1,514)**	1,292	377
End of year	**21,875**	**34,473**	22,586	34,945

Weighted average assumptions

The significant assumptions used to determine the benefit plan cost and accrued benefit obligation were as follows:

	2018		2017	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Discount rate for the year	**3.60%**	**3.60%**	3.90%	3.90%
Average compensation increase for the year (1)	**2.50%**	**n/a**	1.50%	n/a
Accrued benefit obligations				
Discount rate at December 31	**3.80%**	**3.80%**	3.60%	3.60%
Long-term inflation rate	**2.00%**	**n/a**	2.00%	n/a
Health care cost trend rate:				
Drug costs (2)	**n/a**	**5.30%**	n/a	5.43%
Other medical costs	**n/a**	**4.50%**	n/a	4.50%
Dental costs	**n/a**	**4.00%**	n/a	4.00%

(1) The assumed average compensation increase is 1.50 per cent for 2017 and 2.50 per cent thereafter.

(2) The Company uses a graded drug cost trend rate which assumes a rate of 4.50 per cent in 2024.

Defined benefit plan funding

An actuarial valuation for funding purposes as of December 31, 2017 was completed in 2018 for the registered defined benefit pension plans. The estimated contribution for 2019 is $7.0 million. The next actuarial valuation for funding purposes must be completed as of December 31, 2020.

14. BALANCES FROM CONTRACTS WITH CUSTOMERS

Balances from contracts with customers are comprised of trade accounts receivable and contract assets, trade accounts receivable from parent and affiliate companies and customer contributions.

ACCOUNTS RECEIVABLE AND CONTRACT ASSETS

At December 31, trade accounts receivable and contract assets are included in accounts receivable and contract assets:

	2018	2017
Trade accounts receivable and contract assets	**151,185**	119,247
Other accounts receivable	**2,856**	1,495
	154,041	120,742

At December 31, trade accounts receivable from parent and affiliate companies are included in accounts receivable from parent and affiliate companies:

	2018	2017
Trade accounts receivable from parent and affiliate companies	**18,419**	33,592
Other accounts receivable from parent and affiliate companies	**1,223**	1,209
	19,642	34,801

The significant changes in trade accounts receivable and contract assets are as follows:

	Trade accounts receivable and contract assets
December 31, 2016	120,153
Revenue from satisfied performance obligations	1,089,715
Payments received	(1,090,621)
December 31, 2017, as previously reported	119,247
Revenue from satisfied performance obligations	**1,145,026**
Payments received	**(1,113,088)**
December 31, 2018	**151,185**

CUSTOMER CONTRIBUTIONS AND OTHER DEFERRED REVENUES

Certain additions to property, plant and equipment are made with the assistance of non-refundable cash contributions from customers. These contributions are made when the estimated revenue is less than the cost of providing service or where the customer needs special equipment. Since these contributions will provide customers with on-going access to the supply of electricity, they represent deferred revenues and are recognized in revenues over the life of the related asset.

Changes in customer contributions balances and other deferred revenues are summarized below.

December 31, 2016	976,431
Receipt of customer contributions (*Note 17*)	4,754
Amortization (*Note 17*)	(24,396)
December 31, 2017	956,789
Receipt of customer contributions (*Note 17*)	**46,967**
Amortization (*Note 17*)	**(29,579)**
December 31, 2018	**974,177**

	2018	2017
Customer contributions	**974,177**	956,789
Other deferred revenues	**13,484**	26,229
	987,661	983,018

15. EQUITY PREFERRED SHARES

EQUITY PREFERRED SHARES TO CU INC.

Authorized and issued

Authorized: an unlimited number of Preferred Shares, issuable in series.

		2018		2017
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Preferred Shares				
4.60% Series 1	**2,440,000**	**61,000**	2,440,000	61,000
2.243% Series 4	**1,560,000**	**39,000**	1,560,000	39,000
Issuance costs		**(1,702)**		(1,702)
		98,298		98,298

Rights and privileges

Preferred shares	Redemption Amount [1]	Quarterly Dividend [2]	Reset Premium [3]	Date Redeemable/ Convertible	Convertible To
Series 1	25.00	0.2875	Does not reset	Currently redeemable	Not convertible
Series 4	25.00	0.1401875	1.36%	June 1, 2021 [4]	Series 5 [5]

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by the Company or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

EQUITY PREFERRED SHARES TO CANADIAN UTILITIES LIMITED

Authorized and issued

Authorized: an unlimited number of Series Second Preferred Shares, issuable in series.

		2018		2017
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Perpetual Cumulative Second Preferred Shares				
4.60% Series V [1]	**1,748,578**	**43,714**	1,748,578	43,714
Issuance costs		**(44)**		(44)
		43,670		43,670

(1) On October 3, 2017, the annual dividend rate for the Series V Preferred Shares was reset to 4.60 per cent for the next five years. The first payment at the new dividend rate was made on January 3, 2018. Prior to October 3, 2017, the annual dividend rate was 4.00 per cent.

Rights and Privileges

The Series V Perpetual Cumulative Second Preferred Shares are redeemable at the option of the Company at the stated value plus accrued and unpaid dividends.

DIVIDENDS

Cash dividends declared and paid per share are as follows:

(dollars per share)	2018	2017
4.60% Series 1	**1.1500**	1.1500
2.243% Series 4	**0.5608**	0.5608
4.60% Series V	**1.1500**	1.0000

The payment of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On January 10, 2019, the Company declared first quarter eligible dividends of $0.2875 per Series 1 Preferred Share and $0.1401875 per Series 4 Preferred Share.

16. CLASS A AND CLASS B SHARES

The number and dollar amount of outstanding Class A non-voting and Class B common shares at December 31, 2018 is shown below.

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding: December 31, 2017 and 2018	**23,598,608**	**743,698**	**14,463,663**	**468,730**	**38,062,271**	**1,212,428**

Class A and B shares have no par value.

The Company declared and paid cash dividends of $6.83 per Class A non-voting share and Class B common share during 2018 (2017 - $6.96). The payment of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

17. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities are summarized below.

	2018	2017
Depreciation and amortization	**302,944**	292,893
Income taxes	**77,601**	74,461
Contributions by utility customers for extensions to plant (*Note 14*)	**46,967**	4,754
Amortization of customer contributions (*Note 14*)	**(29,579)**	(24,396)
Net finance costs	**218,877**	219,553
Income taxes paid	**(2,172)**	(1,006)
Other	**(14,006)**	14,521
	600,632	580,780

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital are summarized below.

	2018	2017
Operating activities		
Accounts receivable and contract assets	**(32,880)**	(681)
Accounts receivable to parent and affiliate companies	**15,200**	(15,061)
Inventories	**(67)**	120
Prepaid expenses and other current assets	**3,715**	(6,267)
Accounts payable and accrued liabilities	**20,714**	(9,143)
Accounts payable to parent and affiliate companies	**(25,422)**	32,372
Other current liabilities	**–**	30
	(18,740)	1,370
Investing activities		
Inventories	**1,155**	–
Accounts payable and accrued liabilities	**(18,280)**	(15,016)
Accounts receivable and contract assets	**(419)**	
	(17,544)	(15,016)

CASH POSITION

Cash position in the non-consolidated statement of cash flows at December 31 is comprised of:

	2018	2017
Cash	**10,916**	17,929
Short-term advances to parent company	**1,300**	1,272
Bank indebtedness	**(178)**	(5,048)
Short-term advances from parent and affiliated companies	**(54,300)**	(34,772)
	(42,262)	(20,619)

18. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Cash, short-term advances to parent company, accounts receivable and contract assets, accounts receivable from parent and affiliate companies, bank indebtedness, short-term advances from parent and affiliated companies, accounts payable and accrued liabilities and accounts payable to parent and affiliate companies	Assumed to approximate carrying value due to their short-term nature.
Long-term debt	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements (Level 2).

The fair values of the Company's financial instruments measured at amortized cost are as follows:

			2018		2017
Recurring Measurements	Note	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Liabilities					
Long-term debt	12	**5,008,277**	**5,439,510**	4,871,632	5,658,510

OFFSETTING FINANCIAL ASSETS

The following financial assets are subject to offsetting, enforceable master netting arrangements and similar agreements:

			2018			2017
Financial Assets	Gross Amount	Gross Amount Offset	Net Amount Recognized	Gross Amount	Gross Amount Offset	Net Amount Recognized
Accounts receivable and contract assets	**117,918**	**(76,021)**	**41,897**	100,231	(65,067)	35,164

19. RISK MANAGEMENT

FINANCIAL RISKS

The Company is exposed to a variety of risks associated with the use of financial instruments: credit risk and liquidity risk. The Company's Board is responsible for understanding the principal risks of the Company's business, achieving a proper balance between risks incurred and the potential return to the share owner, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of the Company. The Board reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Company's ability to achieve its strategic or operational targets. The Board is also responsible for confirming that management has procedures in place to mitigate identified risks.

The source of risk exposure and how each is managed is outlined below.

CREDIT RISK

Credit risk is the risk of financial loss due to a counterparties inability to discharge their contractual obligations to the Company. The Company is exposed to credit risk on its cash and cash equivalents and accounts receivable and contract assets and accounts receivable from parent and affiliate companies. The exposure to credit risk represents the total carrying amount of these financial instruments in the non-consolidated balance sheet.

The company manages its credit risk on cash and cash equivalents by investing in instruments issued by credit-worthy financial institutions and in short-term instruments issued by the federal government.

The majority of the Company's accounts receivable and contract assets credit risk is reduced by financial security provided by Direct Energy and by retailers in accordance with provisions contained within the Electric Utilities Act Distribution Tariff Regulation A.R. 162/2003, and the Corporation's ability under the Regulation to recover through its distribution tariff any costs not recovered by a claim against such retailer security. At December 31, 2018, the Company held $115 million in letters of credit for certain counterparty receivables (2017 - $107.6 million).

Accounts receivable and contract assets are non-interest bearing and are generally due in 30 to 90 days. The provision for impairment of credit losses was less than $0.5 million in 2018 and 2017. At December 31, 2018, the Company had $0.2 million of trade receivables past due greater than 30 days (2017 - $2.5 million). No other impairments have been identified within accounts receivable.

The Company has also entered into guarantee arrangements with Centrica plc. relating to the retail energy supply functions performed by Direct Energy (see Note 22).

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations associated with its financial liabilities that are settled in cash or another financial asset. Liquidity risk arises from the Company's general funding needs and in the management of its assets, liabilities and capital structure. Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances, bank borrowings, obtaining advances from the parent company and issuance of long-term debt and Class A and B shares. Short term advances from the parent company provide flexibility in the timing and amounts of long term financing.

Lines of credit

The Company has a line of credit available of $10.0 million (2017 - $10.0 million). The credit line enables the Company to obtain financing for general business purposes. At December 31, 2018, $10.0 million of the credit line was available (2017 - $6.6 million).

Maturity analysis of financial obligations

The table below analyzes the remaining contractual maturities at December 31, 2018, of the Company's financial liabilities based on the contractual undiscounted cash flows.

	2019	2020	2021	2022	2023	2024 and thereafter
Bank indebtedness	178	–	–	–	–	–
Short-term advances from parent and affiliated companies	54,300	–	–	–	–	–
Accounts payable and accrued liabilities	115,700	–	–	–	–	–
Accounts payable to parent and affiliate companies	68,244	–	–	–	–	–
Long-term debt:						
Principal	132,044	43,143	101,000	50,010	23,534	4,686,100
Interest expense	230,183	226,433	221,700	213,646	210,922	4,467,020
	600,649	269,576	322,700	263,656	234,456	9,153,120

20. CAPITAL DISCLOSURES

The Company's objective when managing capital is to remain within the capital structure approved by the AUC, which, through the generic cost of capital decisions established the capital structure for the Company. In August 2018, the Company received the 2018 generic cost of capital decision. The decision established the equity ratio for 2018, 2019 and 2020 at 37.0 per cent for transmission and distribution operations. The capitalization involves the use of long term debt and preferred share financings; the AUC approved the continued use of the latter in a decision issued in 2006.

The Company includes share owner’s equity, preferred shares, and long term debt, as adjusted in accordance with the Financial Accounting Standards Board (FASB) standards (see Note 4 and 25), in its determination of capitalization. In maintaining or adjusting its capital structure, the Company may adjust the dividends paid to the share owner, issue or purchase Class A and Class B shares, and issue or redeem preferred shares, and long-term debt.

21. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Significant judgments and estimates made by the Company are outlined below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in the Company's overall business strategy, significant negative industry or economic trends, or adverse decisions by the AUC. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. The Company continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made order to conclude whether a possible impairment exists.

Property, plant and equipment and intangibles

The Company makes judgments to: assess the nature of the costs to be capitalized and the time period over which they are capitalized in the purchase or construction of an asset; evaluate the appropriate level of componentization where an asset is made up of individual components for which different depreciation and amortization methods and useful lives are appropriate; distinguish major overhauls to be capitalized from repair and maintenance activities to be expensed; and determine the useful lives over which assets are depreciated and amortized.

Income taxes

The Company makes judgments with respect to changes in tax legislation, regulations and interpretations thereof. Judgment is also applied to estimating probable outcomes, when temporary differences will reverse, and whether tax assets are realizable.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Revenue recognition

An estimate of usage not yet billed is included in revenues from the regulated distribution of electricity. The estimate is derived from unbilled electricity distribution services supplied to customers and is from the date of the last meter reading and uses historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption.

Impairment of financial assets

The impairment loss allowance for financial assets are based on assumptions about risk of default and expected loss rates. For details regarding significant assumptions and key inputs used to calculate impairment loss allowance, see Note 19.

Useful lives of property, plant and equipment and intangibles

Useful lives are estimated based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Impairment of long-lived assets

The Company continually monitors its long-lived assets and the markets and business environment in which it operates for indications of asset impairment. Where necessary, the Company estimates the recoverable amount for the cash generating unit (CGU) to determine if an impairment loss is to be recognized. These estimates are based on assumptions, such as the price for which the assets in the CGU could be obtained or future cash flows that will be produced by the CGU, discounted at an appropriate rate. Subsequent changes to these estimates or assumptions could significantly impact the carrying value of the assets in the CGU.

Retirement benefits

The Company consults with qualified actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. These assumptions reflect management's best estimates of the long-term inflation rate, projected salary increases, retirement age, discount rate, health care costs trend rates, life expectancy and termination rates. The discount rate is determined by reference to market yields on high quality corporate bonds. Since the discount rate is based on current yields, it is only a proxy for future yields. Key assumptions used to determine the retirement benefit cost and obligation are shown in Note 13.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

22. CONTINGENCIES

Measurement inaccuracies occur from time to time on electricity metering facilities. These measurement adjustments are settled between the parties according to the Electricity and Gas Inspections Act (Canada) and related regulations. The AUC may disallow recovery of a measurement adjustment if it finds that controls and timely follow-up are inadequate.

The Company is party to a number of other disputes and lawsuits in the normal course of business. The Company believes that the ultimate liability arising from these matters will have no material impact on the non-consolidated financial statements.

In 2004, the Company and its affiliate, ATCO Gas, transferred their retail energy supply businesses to Direct Energy. The legal obligations of the Company and ATCO Gas for the retail functions transferred to Direct Energy, which include the supply of natural gas and electricity to customers as well as billing and customer care, remain if Direct Energy fails to perform. In certain circumstances, the functions will revert to the Company and/or ATCO Gas, with no refund of the transfer proceeds to Direct Energy.

Centrica plc., Direct Energy's parent company, provided a $300.0 million guarantee, supported by a $235.0 million letter of credit for Direct Energy's obligations to the Company and ATCO Gas under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to defray all costs that could arise if the obligations are not met.

23. COMMITMENTS

In addition to commitments disclosed elsewhere in the non-consolidated financial statements, the Company has entered into a number of operating leases for office premises and equipment, a contract for information technology services and agreements to purchase capital assets. Approximate future undiscounted payments under these agreements are as follows:

	2019	2020	2021	2022	2023	2024 and thereafter
Operating leases	3,574	3,378	3,320	2,497	2,475	–
Purchase obligations:						
Information technology services	35,259	35,259	35,259	35,259	35,259	35,259
Capital expenditures	53,849	219	–	–	–	–
Other	6,327	119	–	–	–	–
	99,009	38,975	38,579	37,756	37,734	35,259

24. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH RELATED PARTIES

During the year, ATCO Electric entered into the following transactions with related parties:

Entity	Relationship	Transaction	Recorded As	2018	2017
CU Inc. / Canadian Utilities Limited / ATCO Ltd.	Parent	Administration, financial management, aircraft and rent	Other expenses	**52,853**	35,666
		Aircraft, rent and leasehold improvements	Property, plant and equipment	**22,367**	6,848
		Interest income	Interest income	**278**	716
		Long-term and short-term interest expense and guarantee fees	Interest expense	**230,548**	230,415
Northland Utilities Enterprises Ltd.	Subsidiary	Administration, financial management, engineering services, materials management and metering services	Revenues	**851**	1,049
		Long-term and short-term interest income	Interest income	**1,811**	2,015
		Transfer of assets	Property, plant and equipment	**40**	21
ATCO Electric Yukon	Subsidiary	Administration, financial management, materials management and metering services	Revenues	**840**	1,103
		Long-term and short-term interest income	Interest income	**3,401**	3,411
		Short-term interest expense	Interest expense	**80**	35
		Transfer of assets	Property, plant and equipment	**–**	23
ATCO Structures & Logistics	Affiliate	Administration and camp services	Revenues	**10**	565
		Trailer supply and noise management services and purchase of equipment	Property, plant and equipment	**191**	77
		Transfer of assets	Property, plant and equipment	**–**	57
ATCO Gas	Affiliate	Administration and rent	Revenues	**943**	654
		Administration, rent, joint trenching, electronics and instrumentation testing and purchase of equipment	Other expenses	**521**	39
		Contract services	Property, plant and equipment	**–**	542
		Transfer of assets	Property, plant and equipment	**87**	927

Entity	Relationship	Transaction	Recorded As	2018	2017
ATCO Power	Affiliate	Operate and maintain substations, project services, administration, procurement services, metering services and communication services	Revenues	**12,369**	8,234
		Rent	Other expenses	**834**	143
		Transfer of assets	Property, plant and equipment	**–**	1,700
ATCO Energy Solutions Ltd.	Affiliate	Operate and maintain facilities, project services, communication services and administration	Revenues	**220**	375
		Fuel purchases	Fuel costs	**1,381**	1,865
		Transfer of assets	Property, plant and equipment	**–**	19
ATCO Investments Ltd.	Affiliate	Project services	Revenues	**52**	24
		Rent	Other expenses	**3**	16
		Contract services	Property, plant and equipment	**3**	12
ATCO Pipelines	Affiliate	Engineering and land management	Revenues	**148**	132
		Contract services	Other expenses	**–**	24
		Contract services	Property, plant and equipment	**68**	–
		Transfer of assets	Property, plant and equipment	**15**	215
Alberta Power (2000) Ltd.	Affiliate	Administration, metering services, communication services and rent	Revenues	**5**	5
ATCO Energy Ltd.	Affiliate	Billing and call centre services	Revenues	**57**	115
		Retail service revenue	Revenues	**36,314**	23,051
		Distribution service costs	Other expenses	**1,709**	1,389
		Contract services	Other expenses	**19**	3
		Contract services	Property, plant and equipment	**279**	–
Alberta Powerline Limited Partnership	Affiliate	Administration	Revenues	**6,941**	7,904
ATCO-Valard Design Build Joint Venture	Joint Arrangement	Route development and project services	Revenues	**39,154**	34,970

Affiliate companies are subsidiaries of ATCO Electric's parent or ultimate parent.

ATCO Electric incurred $0.4 million (2017 - $0.2 million) in advertising and promotion expenses from an entity related though common control.

These transactions are in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

RELATED PARTY LOANS AND BALANCES

Balances	Recorded As	2018	2017
Receivables from related parties (1)	Accounts receivable from parent company and affiliate companies	**19,642**	34,801
Payables to related parties (1)	Accounts payable to parent company and affiliate companies	**68,244**	93,083
Short-term advances (2)	Short-term advances to parent company	**1,300**	1,272
	Short-term advances from parent company	**54,300**	34,772
Long-term advances *(Note 12)*	Long-term debt to parent company	**5,008,277**	4,871,632
Equity preferred shares *(Note 15)*	Equity preferred shares to parent company	**141,968**	141,968

(1) Generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

(2) Short-term advances are obtained in the normal course of business and are generally due within 30 days or less from the date of the transaction. The interest rates are based on the Bank of Canada overnight rate plus an applicable spread.

Long-term advances to subsidiary companies

Long-term advances to subsidiary companies are shown in the table below.

	Effective Interest Rate	2018	2017
Yukon Electric			
Debentures - unsecured (1)	5.077% (2017 - 5.120%)	**69,000**	66,400
Northland Utilities Yellowknife			
Debentures - unsecured (1)	4.895% (2017 - 4.895%)	**25,363**	25,363
Northland Utilities NWT			
Debentures - unsecured (1)	5.820% (2017 - 5.820%)	**9,300**	9,300
		103,663	101,063
Less: amounts due within one year		**(12,250)**	–
		91,413	101,063

(1) Interest is the average effective interest rate weighted by principal amounts outstanding. The debentures mature between January 2019 and November 2052. Long-term advances are unsecured and will be settled in cash. No provisions are held against the advances.

25. ACCOUNTING POLICIES

RATE REGULATION

Nature and economic effects of rate regulation

The Company is regulated by the AUC. The AUC administers acts and regulations covering such matters as rates, financing, and service area.

Distribution Operations

The distribution operations of the Company are under a form of rate regulation called Performance Based Regulation (PBR). The current PBR period applies for a period of five years from 2018 to 2023. PBR allows distribution utilities the opportunity to recover prudently incurred costs of providing regulatory services and generate a fair return on investment. Under PBR, revenue is determined by a formula that adjusts customer rates for inflation and expected productivity improvements over a five year period.

Specifically, the PBR formula incorporates the following factors:

- Estimated annual inflation for input prices (I Factor)
- Less an offset to reflect expected productivity improvements during the PBR plan period (X Factor)

PBR also includes mechanisms to allow the Company to:

- Recover capital expenditures not recoverable through the PBR formula that meet certain criteria (K Factor)
- Recover from or refund to customers amounts outside of management's ability to control, that are material, should not have significantly influenced the I Factor, are prudently incurred, are recurring and could vary greatly from year to year (Y Factor) or are unforeseen and unlikely to recur (Z Factor).

Transmission Operations

The transmission operations of the Company are subject to a cost of service regulation under which the AUC establishes the revenues required to: (1) recover forecast operating costs of providing the regulated service, including depreciation and amortization and income taxes, and (2) provide a fair and reasonable return on utility investment, or rate base. Since actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base is the investment in property, plant and equipment and intangible assets approved by the AUC. The investment includes an allowance for working capital and is reduced by accumulated depreciation and amortization, reserves for future removal and site restoration costs, and unamortized contributions by utility customers for plant extensions. These operations earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AUC approves rates of return for the debt and preferred share components of rate base which is based on the historical and forecast weighted average cost of debt and preferred shares. The AUC also establishes the capital structure.

The transmission operations of the Company seek approval for their revenue requirement either by submitting a general tariff application to the AUC or negotiating settlement with interested parties. In the latter case, the AUC monitors the negotiated settlement process and approves any agreement. The AUC may approve interim rates or the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

In the absence of a rate-regulated standard under IFRS that the Company is eligible to adopt, the company does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Company records revenues in earnings when amounts are billed to customers consistent with the rate design approved by the AUC (see revenue recognition accounting policy below).

Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meets the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

REVENUE RECOGNITION

Revenue is allocated to the respective performance obligations based on relative transaction prices, and is recognized as goods and services are delivered to the customer. Revenue is measured as the amount of consideration expected to be received in exchange for the goods transferred or services delivered. The amount of revenue recognized reflects the time value of money where a significant financing component has been identified.

Contract modifications are accounted for prospectively or as a cumulative catch-up adjustment depending on the nature of the change.

Where the amount of goods and services delivered to the customer corresponds directly to the amount invoiced, the Company recognizes revenue equal to what it has the right to invoice.

Where the Company arranges for another party to provide a specified good or service (that is, it does not control the specified good or service provided by another party before that good or service is transferred to the customer), only revenues net of payments to the other party for the goods or services provided are recognized.

Non-cash considerations received from the Company's customers are included in the amount of revenue recognized and measured at fair value.

Costs incurred directly to obtain or fulfill a contract are capitalized and amortized to expense over the life of the contract.

Electricity transmission

Revenue from electricity transmission services is recognized when service is provided to customers and is measured in proportion to the amount it has the right to invoice under the contract.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Electricity distribution

Revenue from distribution of electricity is recognized when the services are provided to the customer based on metered consumption, which is adjusted periodically to reflect differences between estimated and actual consumption. Distribution of regulated and non-regulated electricity is based on tariff-approved rates established by the Alberta Electric Systems Operator. The Company recognizes revenue in an amount that corresponds directly with the services delivered and the amount invoiced.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Franchise fees

Municipal governments charge franchise fees to the utilities in Canada for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the regulator. Franchise fees do not represent a separate performance obligation to a customer and are recovered through utility transmission and distribution prices. The recovery is part of the provision of continuous electricity transmission and distribution service performance obligation. Franchise fees invoiced to customers are recognized as revenues.

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. Costs for employee services incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

Termination benefits are recognized as an expense in salaries, wages and benefits at the earlier of when the Company can no longer withdraw the offer of those benefits and when the Company recognizes costs for a restructuring that includes the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income tax is recognized in earnings, except to the extent it relates to items recorded in other comprehensive income (OCI) or in equity.

Current tax is calculated on taxable earnings using rates enacted or substantively enacted at the balance sheet date in the jurisdictions in which the Company operates.

The liability method is used to determine deferred income tax on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred income tax is calculated using the enacted or substantively enacted tax rates that are expected to apply in the period when the liability is settled or the asset is realized. If expected tax rates change, deferred income taxes are adjusted to the new rates.

Deferred income tax assets and liabilities are not recognized if the temporary differences arise from the initial recognition of goodwill or of other assets and liabilities in a transaction, other than a business combination, that does not affect accounting or taxable earnings. Deferred income tax assets are recognized only when it is probable that future taxable earnings will be available against which the temporary differences can be applied.

CASH

Cash consists of cash at bank less outstanding cheques.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less variable selling expenses.

The cost of inventories is comprised of all purchase, conversion and other costs to bring inventories to their present condition and location. Purchase costs consist of the purchase price, import duties, non-recoverable taxes, transport, handling and other costs directly attributable to the purchase of finished goods, materials or services. Conversion costs include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

INVESTMENTS

The Company’s investment in subsidiary companies is initially recognized at cost and only dividends received are taken into earnings. The exemption from applying the consolidation method has been used.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and any recognized impairment losses. Cost includes expenditures that are directly attributable to the purchase or construction of the asset, such as materials, labour, borrowing costs incurred during construction, and contracted services. Subsequent costs are included in the asset’s carrying amount or recognized as a separate asset only when it is probable that future economic benefits will flow to the Company and the cost can be measured reliably.

Borrowing costs attributable to a construction period of substantial duration are added to the cost of the asset. The effective interest method is used to calculate capitalized interest using specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization starts when borrowing costs and expenditures are incurred at the onset of construction and ends when construction is substantially complete.

The Company allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress.

The carrying amount of a replaced asset is derecognized when the cost of replacing the asset is capitalized. When an asset is derecognized, any resulting gain or loss is recorded in earnings.

Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Useful Life	Average Depreciation Rate
Utility transmission and distribution:			
Electricity transmission equipment	2 to 65 years	50 years	2.0%
Electricity distribution equipment	15 to 55 years	37 years	2.7%
Buildings	50 to 55 years	41 years	2.4%
Other plant, equipment and machinery	5 to 25 years	20 years	4.9%

Depreciation methods and the estimated residual values and useful lives of assets are reviewed on an annual basis. Any changes in these accounting estimates are recorded prospectively.

INTANGIBLES

Intangible assets are recorded at cost less accumulated amortization and any recognized impairment losses. The Company amortizes intangible assets on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and between 60 and 80 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

Amortization methods and useful lives of assets are reviewed annually. Any changes in these accounting estimates are recorded prospectively.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability when events or circumstances indicate a possible impairment. Impairment is assessed at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment loss is recognized in earnings when the CGU's carrying value is higher than its recoverable amount. The recoverable amount is the greater of the CGU's fair value less disposal costs and its value in use. An impairment loss may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. A reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

PROVISIONS

The Company recognizes provisions when:

(i) there is a current legal or constructive obligation as a result of a past event;

(ii) a probable outflow of economic benefits will be required to settle the obligation; and

(iii) a reliable estimate of the obligation can be made.

If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

CONTINGENCIES

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the Company. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the consolidated financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

Management evaluates the likelihood of contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

FINANCIAL INSTRUMENTS

The Company classifies financial assets when they are first recognized as amortized cost or fair value through profit or loss. Classification is determined based on the Company's business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are measured at amortized cost if the financial asset is:

(i) held for the purpose of collecting contractual cash flows, and

(ii) the contractual cash flows of the financial asset solely represent payments of principle and interest.

All other financial assets are classified as fair value through profit or loss.

Financial liabilities are classified as amortized cost or fair value through profit or loss.

Amortized cost

Financial instruments classified as amortized cost are initially measured at fair value and subsequently measured at their amortized cost using the effective interest method.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss are initially measured at fair value with subsequent changes in fair value recognized in earnings.

Transaction costs

Transaction costs directly attributable to the purchase or issue of financial assets or financial liabilities that are not fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt are amortized over the life of the respective financial liability using the effective interest method. The Company's long-term debt and equity preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the consolidated balance sheet:

(i) if there is a legally enforceable right to offset the recognized amounts, and

(ii) if the Company intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derecognition of financial instruments

Financial assets are derecognized:

(i) when the right to receive cash flows from the financial assets has expired or been transferred, and

(ii) the Company has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Fair value hierarchy

The Company uses quoted market prices when available to estimate fair value. Models incorporating observable market data, along with transaction specific factors, are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input may affect placement within the fair value hierarchy levels.

The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by the Company and recognizing the disposal of an asset on the day it is delivered by the Company. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

At each reporting date, the Company assesses whether there is evidence that a financial asset or group of financial assets is impaired. If such evidence exists, an impairment loss is recognized in earnings.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. Impairment losses on financial assets carried at amortized cost may be reversed in whole or in part if there is evidence that a change in the estimated recoverable amount is warranted. The revised recoverable amount cannot exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods.

From January 1, 2018, the Company applies the expected credit loss allowance matrix based on historical credit loss experience, aging of financial assets, default probabilities, forward-looking information specific to the counterparty, and industry-specific economic outlooks.

For accounts receivable and contract assets, the Company estimates credit loss allowances at initial recognition and throughout the life of the receivable.

RETIREMENT BENEFITS

The Company participates, together with Canadian Utilities Limited and its subsidiary companies, in a registered group defined benefit pension plan (the Group Plan). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Company is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid. Contributions related to current service cost are allocated in proportion to capped pensionable earnings for each company. Contributions related to the amortization of the unfunded liability are allocated in proportion to the corresponding going-concern liability for each company which was established based on the actuarial valuations for funding purposes as of December 31, 2017.

The minimum funding requirements for the Group Plan are comprised of the contributions related to current service cost and the amortization of the unfunded liability as determined by the actuary. The Company does not have any liability to the Group Plan other than the minimum funding requirements of its subsidiaries. In the event of a withdrawal from the Group Plan or the termination of the Group Plan, the companies will still be required to contribute to the Group Plan where such contributions are required under pension regulations.

The Company participates, together with Canadian Utilities Limited and its subsidiary companies, in OPEB and non-registered group defined benefit pension plans. These plans are administered on a combined basis, and the Company accrues for its obligations under these plans. Costs of these benefits are determined using the projected unit credit method and reflect management's best estimates of wage and salary increases, age at retirement and expected health care costs. The Company consults with qualified actuaries when setting the assumptions used to estimate benefit obligations and the cost of providing retirement benefits during the period.

Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates. The rates are equivalent to those on high quality corporate bonds that match the timing and amount of expected benefit payments.

For the non-registered defined benefit pension plans, the Company is assessed a percentage of the total cost of the plans.

For the non-registered defined benefit pension plan and the OPEB plans, gains and losses resulting from changes in assumptions, including the liability discount rate and future compensation rates, used to measure the accrued benefit obligations are recognized in OCI in the period in which they occur. Those gains and losses are then transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For non-registered defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits, and net interest expense is recognized in interest expense. The cost of retirement benefits for registered defined benefit pension plans and defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment or curtailment. When retirement benefit costs for employee services are incurred in constructing an asset and meet asset recognition criteria, they are included in the related property, plant and equipment or intangible asset.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers of assets between entities under common control are measured at the carrying amount.

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

Certain new or amended standards or interpretations issued by the IASB or IFRIC do not need to be adopted in the current period. The following outlines the new accounting pronouncement that is applicable to, or may have a future material effect on, the Company.

Standard	Description	Effective Date
IFRS 16 *Leases*	This standard replaced IAS 17 *Leases* and related interpretations. It introduces a new approach to lease accounting that requires a lessee to recognize right-of-use assets and lease liabilities for the rights and obligations created by leases. It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. Lessor accounting under the new standard retains similar classifications to the previous guidance, however, the new standard may change the accounting treatment of certain components of lessor contracts and sub-leasing arrangements. The Company is in the process of finalizing its calculations using the modified retrospective approach effective January 1, 2019, without restatement of comparative information. The Company has elected to use certain practical expedients: • Leases of low-value assets and short-term leases that have a lease term of twelve months or less will not be recognized in the balance sheet on January 1, 2019. Payments on these leases will continue to be recognized as a lease expense generally on a straight-line basis over the lease term; and • Right-of-use assets will be measured with an equivalent value recorded for the related lease liabilities. The adoption of the new standard is not expected to have a material impact on the Company's financial statements at January 1, 2019.	Effective for annual periods on or after January 1, 2019.