EB-2022-0028

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application by EPCOR Electricity Distribution Ontario Inc. for an order approving just and reasonable rates and other charges for electricity distribution beginning October 1, 2023.

COMPENDIUM OF THE SCHOOL ENERGY COALITION
(Oral Hearing)

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ONTARIO ENERGY BOARD

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EB-2022-0028

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

SETTLEMENT PROPOSAL

December 9, 2022

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Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,207,078		$1,323,357		$995,812
2	Distribution Revenue	$8,209,408	$8,209,408	$8,204,062	$8,204,062	$8,204,062	$8,531,606
3	Other Operating Revenue Offsets - net	$792,010	$792,010	$796,400	$796,400	$796,400	$796,400
4	**Total Revenue**	$9,001,418	$10,208,496	$9,000,462	$10,323,818	$9,000,462	$10,323,818
5	Operating Expenses	$8,244,016	$8,244,016	$8,224,667	$8,224,667	$8,224,667	$8,224,667
6	Deemed Interest Expense	$778,865	$778,865	$824,214	$824,214	$702,396	$702,396
8	**Total Cost and Expenses**	$9,022,880	$9,022,880	$9,048,881	$9,048,881	$8,927,062	$8,927,062
9	**Utility Income Before Income Taxes**	($21,462)	$1,185,616	($48,419)	$1,274,937	$73,399	$1,396,756
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,185,616)	($1,185,616)	($1,185,616)	($1,185,616)	($1,185,616)	($1,185,616)
11	**Taxable Income**	($1,207,078)	$ -	($1,234,035)	$89,322	($1,112,216)	$211,140
12	Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	($21,462)	$1,185,616	($48,419)	$1,274,937	$73,399	$1,396,756
16	**Utility Rate Base**	$34,226,778	$34,226,778	$34,052,813	$34,052,813	$30,866,392	$30,866,392
17	Deemed Equity Portion of Rate Base	$13,690,711	$13,690,711	$13,621,125	$13,621,125	$12,346,557	$12,346,557
18	Income/(Equity Portion of Rate Base)	-0.16%	8.66%	-0.36%	9.36%	0.59%	11.31%
19	Target Return - Equity on Rate Base	8.66%	8.66%	9.36%	9.36%	8.66%	8.66%
20	Deficiency/Sufficiency in Return on Equity	-8.82%	0.00%	-9.72%	0.00%	-8.07%	2.65%
21	Indicated Rate of Return	2.21%	5.74%	2.28%	6.16%	2.51%	6.80%
22	Requested Rate of Return on Rate Base	5.74%	5.74%	6.16%	6.16%	5.74%	5.74%
23	Deficiency/Sufficiency in Rate of Return	-3.53%	0.00%	-3.89%	0.00%	-3.23%	1.06%
24	Target Return on Equity	$1,185,616	$1,185,616	$1,274,937	$1,274,937	$1,069,212	$1,069,212
25	Revenue Deficiency/(Sufficiency)	$1,207,078	$ -	$1,323,357	$ -	$995,812	$327,544
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,207,078 (1)		$1,323,357 (1)		$995,812 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

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Revenue Requirement Workform (RRWF) for 2022 Filers

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$6,530,315		$6,530,315		$6,530,315	
2	Amortization/Depreciation	$1,688,100		$1,668,751		$1,668,751	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$25,600		$25,600		$25,600	
7	Return						
	Deemed Interest Expense	$778,865		$824,214		$702,396	
	Return on Deemed Equity	$1,185,616		$1,274,937		$1,069,212	
8	**Service Revenue Requirement (before Revenues)**	$10,208,496		$10,323,818		$9,996,274	
9	Revenue Offsets	$792,010		$796,400		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$9,416,486		$9,527,418		$9,996,274	
11	Distribution revenue	$9,416,486		$9,527,418		$9,527,418	
12	Other revenue	$792,010		$796,400		$796,400	
13	**Total revenue**	$10,208,496		$10,323,818		$10,323,818	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$327,544	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Interrogatory Responses	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$10,208,496	$10,323,818	**1.13%**	$9,996,274	#####
Grossed-Up Revenue Deficiency/(Sufficiency)	$1,207,078	$1,323,357	**9.63%**	$995,812	#####
Base Revenue Requirement (to be recovered from Distribution Rates)	$9,416,486	$9,527,418	**1.18%**	$9,996,274	#####
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,207,078	$1,323,357	**9.63%**	$ -	#####

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario [redacted]

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The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2017 of $0.1036/kWh (IESO's Monthly Market Report for May 2017, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.071	1.0602	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.071	1.0602	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.071	1.0602	86,000	250	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.071	1.0602	150		CONSUMPTION	1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.071	1.0602	15,000	100	DEMAND	1,000
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.071	1.0602	750		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.071	1.0602	256		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.071	1.0602	2,000		CONSUMPTION	
Add additional scenarios if required								
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Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 5.58	20.7%	$ 8.58	25.6%	$ 8.54	19.0%	$ 8.61	7.2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 11.72	21.8%	$ 18.72	26.7%	$ 18.66	19.3%	$ 18.79	6.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 415.34	41.1%	$ 753.94	66.0%	$ 763.24	31.7%	$ 748.27	5.3%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 1.29	50.8%	$ 1.56	40.4%	$ 1.55	26.5%	$ 1.56	6.9%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (1,927.27)	-33.7%	$ (1,792.89)	-31.2%	$ (1,790.06)	-29.2%	$ (2,042.68)	-22.9%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 5.58	20.7%	$ 7.29	21.4%	$ 7.26	15.9%	$ 7.31	5.7%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 5.58	20.7%	$ 6.60	22.4%	$ 6.59	19.7%	$ 6.66	11.2%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 11.72	21.8%	$ 15.28	21.3%	$ 15.22	15.5%	$ 15.31	4.8%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	750	kWh
Demand	-	kW
Current Loss Factor	1.0710	
Proposed/Approved Loss Factor	1.0602	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 27.24	1	$ 27.24	$ 31.71	1	$ 31.71	$ 4.47	16.41%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ (0.25)	1	$ (0.25)	$ 0.86	1	$ 0.86	$ 1.11	-444.00%
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 26.99**			**$ 32.57**	**$ 5.58**	**20.67%**
Line Losses on Cost of Power	$ 0.0926	53	$ 4.93	$ 0.0926	45	$ 4.18	$ (0.75)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0026	750	$ 1.95	$ 1.95	
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0016	750	$ 1.20	$ 0.0041	750	$ 3.08	$ 1.88	156.25%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ (0.0001)	750	$ (0.08)	$ (0.08)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.54**			**$ 42.12**	**$ 8.58**	**25.58%**
RTSR - Network	$ 0.0091	803	$ 7.31	$ 0.0092	795	$ 7.32	$ 0.01	0.08%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0051	803	$ 4.10	$ 0.0051	795	$ 4.06	$ (0.04)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 44.95**			**$ 53.49**	**$ 8.54**	**19.01%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	803	$ 3.61	$ 0.0045	795	$ 3.58	$ (0.04)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	803	$ 0.56	$ 0.0007	795	$ 0.56	$ (0.01)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	488	$ 36.08	$ 0.0740	488	$ 36.08	$ -	0.00%
TOU - Mid Peak	$ 0.1020	128	$ 13.01	$ 0.1020	128	$ 13.01	$ -	0.00%
TOU - On Peak	$ 0.1510	135	$ 20.39	$ 0.1510	135	$ 20.39	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 118.84**			**$ 127.34**	**$ 8.50**	**7.15%**
HST	13%		$ 15.45	13%		$ 16.55	$ 1.11	7.15%
Ontario Electricity Rebate	11.7%		$ (13.90)	11.7%		$ (14.90)	$ (0.99)	
Total Bill on TOU			**$ 120.38**			**$ 129.00**	**$ 8.61**	**7.15%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0710
Proposed/Approved Loss Factor	1.0602

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.07	1	$ 23.07	$ 26.79	1	$ 26.79	$ 3.72	16.12%
Distribution Volumetric Rate	$ 0.0153	2000	$ 30.60	$ 0.0178	2000	$ 35.60	$ 5.00	16.34%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0015	2000	$ 3.00	$ 3.00	
Sub-Total A (excluding pass through)			**$ 53.67**			**$ 65.39**	**$ 11.72**	**21.84%**
Line Losses on Cost of Power	$ 0.0926	142	$ 13.15	$ 0.0926	120	$ 11.15	$ (2.00)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ 0.0026	2,000	$ 5.20	$ 5.20	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0014	2,000	$ 2.80	$ 0.0034	2,000	$ 6.80	$ 4.00	142.86%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ (0.0001)	2,000	$ (0.20)	$ (0.20)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 70.04**			**$ 88.76**	**$ 18.72**	**26.73%**
RTSR - Network	$ 0.0083	2,142	$ 17.78	$ 0.0084	2,120	$ 17.81	$ 0.03	0.18%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0042	2,142	$ 9.00	$ 0.0042	2,120	$ 8.91	$ (0.09)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 96.82**			**$ 115.48**	**$ 18.66**	**19.27%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,142	$ 9.64	$ 0.0045	2,120	$ 9.54	$ (0.10)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	2,142	$ 1.50	$ 0.0007	2,120	$ 1.48	$ (0.02)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	1,300	$ 96.20	$ 0.0740	1,300	$ 96.20	$ -	0.00%
TOU - Mid Peak	$ 0.1020	340	$ 34.68	$ 0.1020	340	$ 34.68	$ -	0.00%
TOU - On Peak	$ 0.1510	360	$ 54.36	$ 0.1510	360	$ 54.36	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 293.45**			**$ 311.99**	**$ 18.55**	**6.32%**
HST	13%		$ 38.15	13%		$ 40.56	$ 2.41	6.32%
Ontario Electricity Rebate	11.7%		$ (34.33)	11.7%		$ (36.50)	$ (2.17)	
Total Bill on TOU			**$ 297.26**			**$ 316.05**	**$ 18.79**	**6.32%**

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	Non-RPP (Other)
Consumption	**86,000** kWh
Demand	**250** kW
Current Loss Factor	**1.0710**
Proposed/Approved Loss Factor	**1.0602**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 110.21	1	$ 110.21	$ 110.21	1	$ 110.21	$ -	0.00%
Distribution Volumetric Rate	$ 3.6042	250	$ 901.05	$ 4.6242	250	$ 1,156.05	$ 255.00	28.30%
Fixed Rate Riders	$ -	1	$ -	$ 89.44	1	$ 89.44	$ 89.44	
Volumetric Rate Riders	$ -	250	$ -	$ 0.2836	250	$ 70.90	$ 70.90	
Sub-Total A (excluding pass through)			**$ 1,011.26**			**$ 1,426.60**	**$ 415.34**	**41.07%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	250	$ -	$ 1.0880	250	$ 272.00	$ 272.00	
CBR Class B Rate Riders	$ -	250	$ -	$ -	250	$ -	$ -	
GA Rate Riders	$ -	86,000	$ -	$ (0.0016)	86,000	$ (137.60)	$ (137.60)	
Low Voltage Service Charge	$ 0.5215	250	$ 130.38	$ 1.3608	250	$ 340.20	$ 209.83	160.94%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		250	$ -	$ (0.0225)	250	$ (5.63)	$ (5.63)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,141.64**			**$ 1,895.58**	**$ 753.94**	**66.04%**
RTSR - Network	$ 3.2679	250	$ 816.98	$ 3.2907	250	$ 822.68	$ 5.70	0.70%
RTSR - Connection and/or Line and Transformation Connection	$ 1.7842	250	$ 446.05	$ 1.7986	250	$ 449.65	$ 3.60	0.81%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2,404.66**			**$ 3,167.90**	**$ 763.24**	**31.74%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	92,106	$ 414.48	$ 0.0045	91,177	$ 410.30	$ (4.18)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	92,106	$ 64.47	$ 0.0007	91,177	$ 63.82	$ (0.65)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	92,106	$ 9,542.18	$ 0.1036	91,177	$ 9,445.96	$ (96.22)	-1.01%
Total Bill on Average IESO Wholesale Market Price			**$ 12,426.04**			**$ 13,088.23**	**$ 662.19**	**5.33%**
HST	13%		$ 1,615.39	13%		$ 1,701.47	$ 86.08	5.33%
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 14,041.43**			**$ 14,789.70**	**$ 748.27**	**5.33%**

Customer Class:	**UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION**
RPP / Non-RPP:	Non-RPP (Other)
Consumption	**150** kWh
Demand	**-** kW
Current Loss Factor	**1.0710**
Proposed/Approved Loss Factor	**1.0602**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 0.56	1	$ 0.56	$ 0.80	1	$ 0.80	$ 0.24	42.86%
Distribution Volumetric Rate	$ 0.0132	150	$ 1.98	$ 0.0190	150	$ 2.85	$ 0.87	43.94%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	150	$ -	$ 0.0012	150	$ 0.18	$ 0.18	
Sub-Total A (excluding pass through)			**$ 2.54**			**$ 3.83**	**$ 1.29**	**50.79%**
Line Losses on Cost of Power	$ 0.1036	11	$ 1.10	$ 0.1036	9	$ 0.94	$ (0.17)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	150	$ -	$ 0.0026	150	$ 0.39	$ 0.39	
CBR Class B Rate Riders	$ -	150	$ -	$ -	150	$ -	$ -	
GA Rate Riders	$ -	150	$ -	$ (0.0016)	150	$ (0.24)	$ (0.24)	
Low Voltage Service Charge	$ 0.0014	150	$ 0.21	$ 0.0034	150	$ 0.51	$ 0.30	142.86%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		150	$ -	$ (0.0001)	150	$ (0.02)	$ (0.02)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3.85**			**$ 5.41**	**$ 1.56**	**40.41%**
RTSR - Network	$ 0.0083	161	$ 1.33	$ 0.0084	159	$ 1.34	$ 0.00	0.18%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0042	161	$ 0.67	$ 0.0042	159	$ 0.67	$ (0.01)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 5.86**			**$ 7.41**	**$ 1.55**	**26.49%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	161	$ 0.72	$ 0.0045	159	$ 0.72	$ (0.01)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	161	$ 0.11	$ 0.0007	159	$ 0.11	$ (0.00)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	150	$ 15.54	$ 0.1036	150	$ 15.54	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 22.49**			**$ 24.03**	**$ 1.54**	**6.87%**
HST	13%		$ 2.92	13%		$ 3.12	$ 0.20	6.87%
Ontario Electricity Rebate	11.7%		$ (2.63)	11.7%		$ (2.81)		
Total Bill on Average IESO Wholesale Market Price			**$ 22.78**			**$ 24.34**	**$ 1.56**	**6.87%**

Customer Class:	**STREET LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	Non-RPP (Other)
Consumption	**15,000** kWh
Demand	**100** kW
Current Loss Factor	**1.0710**
Proposed/Approved Loss Factor	**1.0602**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 4.03	1000	$ 4,030.00	$ 1.90	1000	$ 1,900.00	$ (2,130.00)	-52.85%
Distribution Volumetric Rate	$ 16.8079	100	$ 1,680.79	$ 7.9718	100	$ 797.18	$ (883.61)	-52.57%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	100	$ -	$ 10.8634	100	$ 1,086.34	$ 1,086.34	
Sub-Total A (excluding pass through)			**$ 5,710.79**			**$ 3,783.52**	**$ (1,927.27)**	**-33.75%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	100	$ -	$ 0.9544	100	$ 95.44	$ 95.44	
CBR Class B Rate Riders	$ -	100	$ -	$ -	100	$ -	$ -	
GA Rate Riders	$ -	15,000	$ -	$ (0.0016)	15,000	$ (24.00)	$ (24.00)	
Low Voltage Service Charge	$ 0.4031	100	$ 40.31	$ 1.0520	100	$ 105.20	$ 64.89	160.98%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		100	$ -	$ (0.0195)	100	$ (1.95)	$ (1.95)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 5,751.10**			**$ 3,958.21**	**$ (1,792.89)**	**-31.17%**
RTSR - Network	$ 2.4646	100	$ 246.46	$ 2.4818	100	$ 248.18	$ 1.72	0.70%
RTSR - Connection and/or Line and Transformation Connection	$ 1.3793	100	$ 137.93	$ 1.3904	100	$ 139.04	$ 1.11	0.80%
Sub-Total C - Delivery (including Sub-Total B)			**$ 6,135.49**			**$ 4,345.43**	**$ (1,790.06)**	**-29.18%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	16,065	$ 72.29	$ 0.0045	15,903	$ 71.56	$ (0.73)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	16,065	$ 11.25	$ 0.0007	15,903	$ 11.13	$ (0.11)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	16,065	$ 1,664.33	$ 0.1036	15,903	$ 1,647.55	$ (16.78)	-1.01%
Total Bill on Average IESO Wholesale Market Price			**$ 7,883.61**			**$ 6,075.93**	**$ (1,807.69)**	**-22.93%**
HST	13%		$ 1,024.87	13%		$ 789.87	$ (235.00)	-22.93%
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 8,908.48**			**$ 6,865.80**	**$ (2,042.68)**	**-22.93%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0710
Proposed/Approved Loss Factor	1.0602

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 27.24	1	$ 27.24	$ 31.71	1	$ 31.71	$ 4.47	16.41%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ (0.25)	1	$ (0.25)	$ 0.86	1	$ 0.86	$ 1.11	-444.00%
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 26.99**			**$ 32.57**	**$ 5.58**	**20.67%**
Line Losses on Cost of Power	$ 0.1036	53	$ 5.52	$ 0.1036	45	$ 4.68	$ (0.84)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0026	750	$ 1.95	$ 1.95	
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ (0.0016)	750	$ (1.20)	$ (1.20)	
Low Voltage Service Charge	$ 0.0016	750	$ 1.20	$ 0.0041	750	$ 3.08	$ 1.88	156.25%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ (0.0001)	750	$ (0.08)	$ (0.08)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 34.13**			**$ 41.42**	**$ 7.29**	**21.36%**
RTSR - Network	$ 0.0091	803	$ 7.31	$ 0.0092	795	$ 7.32	$ 0.01	0.08%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0051	803	$ 4.10	$ 0.0051	795	$ 4.06	$ (0.04)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.53**			**$ 52.79**	**$ 7.26**	**15.93%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	803	$ 3.61	$ 0.0045	795	$ 3.58	$ (0.04)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	803	$ 0.56	$ 0.0007	795	$ 0.56	$ (0.01)	-1.01%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	750	$ 77.70	$ 0.1036	750	$ 77.70	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 127.41**			**$ 134.62**	**$ 7.21**	**5.66%**
HST	13%		$ 16.56	13%		$ 17.50	$ 0.94	5.66%
Ontario Electricity Rebate	11.7%		$ (14.91)	11.7%		$ (15.75)		
Total Bill on Non-RPP Avg. Price			**$ 129.07**			**$ 136.37**	**$ 7.31**	**5.66%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	256 kWh
Demand	- kW
Current Loss Factor	1.0710
Proposed/Approved Loss Factor	1.0602

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 27.24	1	$ 27.24	$ 31.71	1	$ 31.71	$ 4.47	16.41%
Distribution Volumetric Rate	$ -	256	$ -	$ -	256	$ -	$ -	
Fixed Rate Riders	$ (0.25)	1	$ (0.25)	$ 0.86	1	$ 0.86	$ 1.11	-444.00%
Volumetric Rate Riders	$ -	256	$ -	$ -	256	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 26.99**			**$ 32.57**	**$ 5.58**	**20.67%**
Line Losses on Cost of Power	$ 0.0926	18	$ 1.68	$ 0.0926	15	$ 1.43	$ (0.26)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	256	$ -	$ 0.0026	256	$ 0.67	$ 0.67	
CBR Class B Rate Riders	$ -	256	$ -	$ -	256	$ -	$ -	
GA Rate Riders	$ -	256	$ -	$ -	256	$ -	$ -	
Low Voltage Service Charge	$ 0.0016	256	$ 0.41	$ 0.0041	256	$ 1.05	$ 0.64	156.25%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		256	$ -	$ (0.0001)	256	$ (0.03)	$ (0.03)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 29.50**			**$ 36.11**	**$ 6.60**	**22.38%**
RTSR - Network	$ 0.0091	274	$ 2.50	$ 0.0092	271	$ 2.50	$ 0.00	0.08%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0051	274	$ 1.40	$ 0.0051	271	$ 1.38	$ (0.01)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 33.40**			**$ 39.99**	**$ 6.59**	**19.74%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	274	$ 1.23	$ 0.0045	271	$ 1.22	$ (0.01)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	274	$ 0.19	$ 0.0007	271	$ 0.19	$ (0.00)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	166	$ 12.31	$ 0.0740	166	$ 12.31	$ -	0.00%
TOU - Mid Peak	$ 0.1020	44	$ 4.44	$ 0.1020	44	$ 4.44	$ -	0.00%
TOU - On Peak	$ 0.1510	46	$ 6.96	$ 0.1510	46	$ 6.96	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 58.78**			**$ 65.36**	**$ 6.58**	**11.19%**
HST	13%		$ 7.64	13%		$ 8.50	$ 0.86	11.19%
Ontario Electricity Rebate	11.7%		$ (6.88)	11.7%		$ (7.65)	$ (0.77)	
Total Bill on TOU			**$ 59.55**			**$ 66.21**	**$ 6.66**	**11.19%**

Customer Class:	**GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**2,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0710**
Proposed/Approved Loss Factor	**1.0602**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.07	1	$ 23.07	$ 26.79	1	$ 26.79	$ 3.72	16.12%
Distribution Volumetric Rate	$ 0.0153	2000	$ 30.60	$ 0.0178	2000	$ 35.60	$ 5.00	16.34%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0015	2000	$ 3.00	$ 3.00	
Sub-Total A (excluding pass through)			**$ 53.67**			**$ 65.39**	**$ 11.72**	**21.84%**
Line Losses on Cost of Power	$ 0.1036	142	$ 14.71	$ 0.1036	120	$ 12.47	$ (2.24)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ 0.0026	2,000	$ 5.20	$ 5.20	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ (0.0016)	2,000	$ (3.20)	$ (3.20)	
Low Voltage Service Charge	$ 0.0014	2,000	$ 2.80	$ 0.0034	2,000	$ 6.80	$ 4.00	142.86%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ (0.0001)	2,000	$ (0.20)	$ (0.20)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 71.60**			**$ 86.88**	**$ 15.28**	**21.34%**
RTSR - Network	$ 0.0083	2,142	$ 17.78	$ 0.0084	2,120	$ 17.81	$ 0.03	0.18%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0042	2,142	$ 9.00	$ 0.0042	2,120	$ 8.91	$ (0.09)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 98.38**			**$ 113.60**	**$ 15.22**	**15.48%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,142	$ 9.64	$ 0.0045	2,120	$ 9.54	$ (0.10)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	2,142	$ 1.50	$ 0.0007	2,120	$ 1.48	$ (0.02)	-1.01%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	2,000	$ 207.20	$ 0.1036	2,000	$ 207.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 316.71**			**$ 331.83**	**$ 15.11**	**4.77%**
HST	13%		$ 41.17	13%		$ 43.14	$ 1.96	4.77%
Ontario Electricity Rebate	11.7%		$ (37.06)	11.7%		$ (38.82)		
Total Bill on Non-RPP Avg. Price			**$ 320.83**			**$ 336.14**	**$ 15.31**	**4.77%**

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Appendix 2-AA
Capital Projects Table

	2013 OEB Approved	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
SYSTEM RENEWAL												
Pole line rebuild	719,155	302,620	489,287	411,970	533,955	1,100,367	624,202	1,941,992	1,285,638	1,513,561	1,204,953	1,276,043
Underground rebuild	91,393	0	19,372	3,730	35,004	39,401	212,542	28,312	119,524	636,824	364,516	67,830
Substation rebuild	0	0	106,412	0	0	0	0	0	37,562	3,605	137,400	140,330
Pole replacement program	240,160	311,542	222,714	234,602	335,339	465,401	370,665	196,641	587,011	595,826	558,491	582,540
Transformer replacement	0	0	130,153	139,671	324,788	561,697	99,007	209,786	11,091	850	0	0
Misc Pole OH												
Subtotal	**1,050,708**	**614,162**	**967,938**	**789,973**	**1,229,086**	**2,166,866**	**1,306,416**	**2,376,731**	**2,040,826**	**2,750,666**	**2,265,360**	**2,066,743**
SYSTEM ACCESS												
Road Authority		13,819	163,369	276,219	0	0	0	0	0	0	18,500	281,500
Road Authority Contributions		-6,910	-81,684	-138,110	0	0	0	0	0	0	-6,167	-93,833
Customer Demanded	425,000	177,228	224,005	634,745	1,786,670	505,788	1,021,563	700,371	1,374,126	1,233,475	1,308,441	323,631
Customer Demanded Contributions		-248,339	-195,535	-549,274	-1,693,404	-415,215	-954,882	-626,843	-873,408	-600,278	-1,170,381	-456,721
Service	150,000	132,608	148,688	130,906	147,809	211,762	253,294	342,214	188,611	190,935	143,854	348,742
Service Contributions	-350,000	-67,862	-74,012	-58,189	-46,185	-112,742	-49,574	-184,823	-212,703	-89,866	-76,488	-180,118
Meter	275,500	191,556	235,691	264,657	63,702	138,064	143,938	126,286	177,041	119,173	190,000	377,878
Subtotal	**500,500**	**192,101**	**420,522**	**560,954**	**258,592**	**327,657**	**414,339**	**357,205**	**653,667**	**853,439**	**407,760**	**601,079**
SYSTEM SERVICE												
Creemore 8.32kV feeder - Hydro One	0	0	0	122,895	572,269	0	2,956	0	0	0	0	0
Substation upgrades	0	0	0	0	0	0	0	0	0	0	0	689,014
Customer Enhancement	0	0	0	0	0	0	0	0	0	0	0	40,000
ArcPro and UN Migration	0	0	0	0	0	0	0	0	0	0	0	508,602
SCADA	40,000	13,411	13,696	35,068	2,000	36,226	0	305,635	8,085	71,150	102,550	135,000
Subtotal	**40,000**	**13,411**	**13,696**	**157,963**	**574,269**	**36,226**	**2,956**	**305,635**	**8,085**	**71,150**	**102,550**	**1,372,616**
GENERAL PLANT												
Land, Buildings & Equipment	75,000	30,802	69,181	27,996	22,989	45,217	9,584	248,173	47,378	35,564	160,339	0
Hardware / Software	105,000	41,952	54,969	66,275	131,262	25,036	16,243	305,741	63,227	64,281	43,874	45,400
Vehicles	202,000	164,943	262,918	39,115	354,140	388,939	113,100	540,882	463,574	0	716,702	210,000
Subtotal	**382,000**	**237,698**	**387,068**	**133,386**	**508,391**	**459,192**	**138,927**	**1,094,796**	**574,179**	**99,845**	**920,915**	**255,400**
OTHER												
Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total	**1,973,208**	**1,057,371**	**1,789,224**	**1,642,276**	**2,570,338**	**2,989,941**	**1,862,638**	**4,134,367**	**3,276,757**	**3,775,100**	**3,696,585**	**4,295,838**

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TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

2023

Historical Period (previous plan[1] & actual)

CATEGORY	2013 Plan	2013 OEB Approved	2013 Var	2013 Plan	2013 Actual	2013 Var	2014 Plan	2014 Actual	2014 Var	2015 Plan	2015 Actual	2015 Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	850,500	850,500	0.0%	850,500	515,211	-39.4%	775,500	771,753	-0.5%	775,500	1,306,527	68.5%
System Renewal	1,050,708	1,050,708	0.0%	1,050,708	614,162	-41.5%	1,550,297	967,938	-37.6%	2,003,005	789,973	-60.6%
System Service	40,000	40,000	0.0%	40,000	13,411	-66.5%	40,000	13,696	-65.8%	740,000	157,963	-78.7%
General Plant	382,000	382,000	0.0%	382,000	237,698	-37.8%	505,000	387,068	-23.4%	220,000	133,386	-39.4%
TOTAL EXPENDITURE	2,323,208	2,323,208	0.0%	2,323,208	1,380,482	-40.6%	2,870,797	2,140,455	-25.4%	3,738,505	2,387,849	-36.1%
Capital Contributions	- 350,000	- 350,000	0.0%	- 350,000	- 323,111	-7.7%	- 350,000	- 351,231	0.4%	- 350,000	- 745,573	113.0%
Net Capital Expenditures	1,973,208	1,973,208	0.0%	1,973,208	1,057,371	-46.4%	2,520,797	1,789,224	-29.0%	3,388,505	1,642,276	-51.5%
System O&M	$ 1,945,300	$ 2,073,000	6.6%	$1,945,300	$ 2,053,457	5.6%	$2,130,006	$2,169,113	1.8%	$ 2,230,665	$2,388,712	7.1%

CATEGORY	2016 Plan	2016 Actual	2016 Var	2017 Plan	2017 Actual	2017 Var	2018 Plan	2018 Actual	2018 Var	2019 Plan	2019 Actual	2019 Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	768,753	1,998,181	159.9%	752,909	855,614	13.6%	1,039,693	1,418,795	36.5%	779,089	1,168,871	50.0%
System Renewal	2,524,177	1,229,086	-51.3%	2,115,500	2,166,866	2.4%	1,895,340	1,306,416	-31.1%	2,117,880	2,376,731	12.2%
System Service	49,200	574,269	1067.2%	51,087	36,226	-29.1%	51,087	2,956	-94.2%	300,000	305,635	1.9%
General Plant	621,150	508,391	-18.2%	626,334	459,192	-26.7%	651,930	138,927	-78.7%	569,210	1,094,796	92.3%
TOTAL EXPENDITURE	3,963,280	4,309,927	8.7%	3,545,830	3,517,897	-0.8%	3,638,050	2,867,094	-21.2%	3,766,179	4,946,033	31.3%
Capital Contributions	- 449,875	- 1,739,589	286.7%	- 449,875	- 527,957	17.4%	- 458,423	- 1,004,456	119.1%	- 467,133	- 811,666	73.8%
Net Capital Expenditures	3,513,405	2,570,338	-26.8%	3,095,955	2,989,941	-3.4%	3,179,627	1,862,638	-41.4%	3,299,046	4,134,367	25.3%
System O&M	$2,297,585	$ 2,482,131	8.0%	$2,517,407	$2,189,894	-13.0%	$ -	$ 2,310,043	--	$ -	$ 2,258,487	--

Forecast Period (planned)

CATEGORY	2020 Plan	2020 Actual	2020 Var	2021 Plan	2021 Actual	2021 Var	2022 Plan	2022 Actual[2]	2022 Var	2023	2024	2025	2026	2027
	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	993,236	1,739,778	75.2%	1,008,318	1,543,583	53.1%	2,279,019	1,660,796	-27.1%	1,331,751	1,361,747	1,393,275	1,426,425	1,461,301
System Renewal	2,449,813	2,040,826	-16.7%	2,594,023	2,750,666	6.0%	2,025,599	2,265,360	11.8%	2,066,743	2,208,280	2,095,048	2,168,837	2,103,654
System Service	75,000	8,085	-89.2%	101,875	71,150	-30.2%	103,979	102,550	-1.4%	1,372,616	958,750	681,595	479,037	519,037
General Plant	657,757	574,179	-12.7%	693,180	99,845	-85.6%	440,548	920,915	109.0%	255,400	709,126	420,764	476,759	579,770
TOTAL EXPENDITURE	4,175,806	4,362,868	4.5%	4,397,396	4,465,244	1.5%	4,849,145	4,949,621	2.1%	5,026,510	5,237,903	4,590,682	4,551,058	4,663,762
Capital Contributions	- 476,009	- 1,086,111	128.2%	- 654,494	- 690,144	5.4%	- 1,391,830	- 1,253,036	-10.0%	- 730,672	- 747,130	- 764,428	- 782,615	- 801,750
Net Capital Expenditures	3,699,797	3,276,757	-11.4%	3,742,902	3,775,100	0.9%	3,457,315	3,696,585	6.9%	4,295,838	4,490,774	3,826,255	3,768,443	3,862,012
System O&M	$ -	$ 2,785,865	--	$ -	$2,452,353	--	$2,438,752	$2,438,752	0.0%	$2,617,273	$ 2,708,877	$ 2,803,688	$ 2,901,817	$ 3,003,381

Table 2.1-1
Summary of Historical and Projected Rate Base
($ 000's)

		A	C	D	E	F	G	H	I	J	K	L
		2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
		OEB Approved	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Bridge**	**Test**
		CGAAP	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
1	Opening Balance, January 1	15,254	15,065	15,483	31,547	17,345	19,146	19,865	23,323	25,053	25,721	**29,877**
3	Closing Balance, December 31	15,857	15,483	31,547	17,345	19,146	19,865	23,323	25,053	25,721	29,877	**32,333**
4	**Net Fixed Assets (average)**	**15,556**	**15,274**	**23,515**	**24,446**	**18,246**	**19,506**	**21,594**	**24,188**	**25,387**	**27,799**	**31,105**
6	Controllable Expenses	4,585	4,564	4,705	4,921	4,618	4,859	5,594	6,111	5,648	6,163	**6,556**
7	Cost of Power	29,473	32,978	33,644	36,667	34,705	34,769	36,125	41,646	37,786	36,426	**35,066**
8	Working Capital Base	34,059	37,542	38,349	41,588	39,323	39,628	41,719	47,757	43,435	42,589	**41,622**
9	Working Capital Rate %	12%	12%	12%	12%	12%	12%	12%	12%	12%	7.5%	**7.5%**
10	**Working Capital Allowance**	**4,087**	**4,505**	**4,602**	**4,991**	**4,719**	**4,755**	**5,006**	**5,731**	**5,212**	**3,194**	**3,122**
11												
12	**Total Rate Base**	**19,643**	**19,779**	**28,116**	**29,436**	**22,964**	**24,261**	**26,600**	**29,919**	**30,599**	**30,993**	**34,227**
13												
14	YOY Variance ($)		136	8,338	1,320	-6,472	1,296	2,339	3,319	680	394	**3,234**
15	YOY Variance (%)		1%	42%	5%	-22%	6%	10%	12%	2%	1%	**10%**

2.1.1 Test Year Rate Base Variance Analysis

The following section outlines EEDO's rate base and working capital allowance calculations and explanations of variances from its previous 2013 Cost of Service Application and the 2023 Test Year.

Table 2.1.1-1
2013 OEB Approved vs. 2023 Test Year – Rate Base ($ 000's)

		A **2013 Test**	B **2023 Test**	C **Variance $**	D **Variance %**
1					
2	Opening Balance, January 1	15,254	29,877	14,623	96%
3	Closing Balance, December 31	15,857	32,333	16,475	104%
4	**Net Fixed Assets (average)**	15,556	**31,105**	**15,549**	**100%**
5					
6	Controllable Expenses	4,585	6,556	1,971	43%
7	Cost of Power	29,473	35,066	5,593	19%
8	Working Capital Base	34,059	41,622	7,563	22%
9	Working Capital Rate %	12.0%	7.5%	-4.5%	-38%
10	**Working Capital Allowance**	4,087	**3,122**	**(965)**	**-24%**
11					
12	**Total Rate Base**	19,643	**34,227**	**14,584**	**74%**

The variance between the 2013 OEB Approved amounts and the 2023 Test Year is largely due to an increase in the average net fixed assets of $15.5M as a result of capital additions over the 10-year 2013-2023 period. EEDO has invested heavily in its distribution system since the last Cost of Service application, including significant one-time investments discussed further below.

The majority of EEDO initiated investments are focused on System Renewal (to maintain the existing level of system reliability by replacing assets at end-of-life and most at risk of failure), and System Access (investments to accommodate new connections, growth, and infrastructure relocations due to third party requests). Further fixed asset variance detail is provided in section 2.2 - Fixed Asset Continuity Schedule along with EEDO's 2023-2027 Distribution System Plan.

Since the previous rebasing in 2013, EEDO has experienced an 18% increase in customer count (1.7% CAGR), mainly residential (20%), but also 7% small commercial (GS<50kW) and 8% in large commercial, multi-unit residential and industrial (GS>50kW) rate classes.

There is projected to be an 11% increase in overall kWh consumption between 2013 and 2023 Average consumption per customer is decreasing most significantly in street lighting customers due to the implementation of LED retrofit CDM projects in 2018 as part of the Conservation First Framework.

The increase in net fixed assets are offset by a decrease in working capital allowance, largely driven by the decrease in the working capital allowance effective rate from 12% to 7.5%. Detailed explanations of variances are included further in this Exhibit and in other referenced Exhibits in this application.

EEDO experienced an average of 3.5% per year increased in controllable expenses (which excludes depreciation expense). Additional justification and rationale for increases in controllable expenses can be found in Exhibit 4.

As shown in Table 2.1-1 above, the cost of power has fluctuated over the 10 year term of this application, peaking in 2020 but is projected to decrease in the 2023 test year despite a 1.1% annual increase in kWh consumption in EEDO's service territory. This is in part due to a reallocation of global adjustment costs, as approximately 85 per cent of non-hydro renewable energy contract costs have been shifted from the rate base to the tax base as well as ongoing benefits from conservation and demand management initiatives. Details of the 2023 test year cost of power calculation are included further in this Exhibit in section 2.5.1 - Calculation of Cost of Power.

2.2 Fixed Asset Continuity Schedule

EEDO has completed Fixed Asset Continuity Schedules, in accordance with Appendix 2- BA of the Filing Requirements, for each of the following years:

- 2013 OEB Approved (EB-2012-0116)
- 2013-2021 Actual
- 2022 Bridge Year
- 2023 Test Year

EEDO attests that the OEB Appendices 2-BA continuity statements presented at the next page reconcile with the calculated depreciation expenses in the tables shown in Section 2.4.5, and presented by asset account. The utility also attests that the net book value balances reported on Appendix 2-BA and balances reconcile with the rate base calculation. The Excel version of the OEB Appendices is filed in conjunction with this application.

Information on year-over-year variances are further explained in detail in section 2.3 below along with EEDO's Distribution System Plan, which has been included as Exhibit 2, Tab 3, Schedule 1 and in section 2.3. EEDO does not have any Asset Retirement Obligation related to decommissioning.

Table 2.2-1 includes a summary of those continuity schedules.

Table 2.2-1 Fixed Asset Continuity Schedule Summary ($ 000’s)

		A	C	D	E	F	G	H	I	J	K	L
		2013 Test	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Actual**	**2022 Bridge**	**2023 Test**
		CGAAP	***CGAAP***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***
1	***Gross Fixed Assets***											
2	Opening Balance	30,980	31,564	32,647	33,508	20,310	23,132	24,886	29,530	32,596	34,793	40,506
3	Additions	1,789	2,152	1,710	2,613	2,934	2,047	5,735	3,250	3,657	4,038	4,296
4	**Disposals**	-	199	238	216	(90)	(125)	(155)	(225)	-	(89)	(65)
5	Closing Balance (excluding WIP)	32,770	32,647	33,508	20,310	23,132	24,886	29,530	32,596	34,793	40,506	44,736
6												
7	Average Gross Fixed Assets	31,875	32,105	33,077	26,909	21,721	24,009	27,208	31,063	33,695	37,649	42,621
8												
9	***Accumulated Depreciation***											
10	Opening	(15,757)	-	(1,020)	(1,962)	(2,965)	(3,986)	(5,021)	(6,207)	(7,543)	(9,073)	(10,628)
11	Additions	(1,094)	(1,010)	(966)	(1,016)	(1,092)	(1,102)	(1,333)	(1,446)	(1,529)	(1,644)	(1,840)
12	Disposals	(30)	(10)	25	13	71	66	147	109	-	89	65
13	**Closing Balance**	(16,881)	(1,020)	(1,962)	(2,965)	(3,986)	(5,021)	(6,207)	(7,543)	(9,073)	(10,628)	(12,403)
14												
15	**Average Accumulated Depreciation**	(16,319)	(510)	(1,491)	(2,463)	(3,475)	(4,504)	(5,614)	(6,875)	(8,308)	(9,850)	(11,516)
16												
17	Net Fixed Assets	15,556	31,595	31,587	24,446	18,246	19,506	21,594	24,188	25,387	27,799	31,105

EEDO transferred to IFRS reporting in 2015, which contributes to the large variance of accumulated depreciation shown in 2015. While the balance is presented in IFRS above, a reconciliation and continuity schedules comparison is provided further in this exhibit. EEDO elected to follow the rate-regulated deemed cost exemption in converting from CGAAP to MIFRS at January 1, 2014. As a result, the deemed cost under CGAAP became the new IFRS cost basis with accumulated depreciation recognized under CGAAP set to nil.

Table 2.2-2 below reconciles the change in Accumulated Depreciation, shown above, to the annual depreciation expense (as reported in Exhibit 2, Section 4.6, 'Depreciation and Amortization Expense'), as per Section 2.2.1.2 of the Filing Requirements.

Table 2.2-2 – Reconciliation of Change in Accumulated Depreciation to Depreciation Expense ($000's)

		A **2013** **Test**	C **2014** **Actual**	D **2015** **Actual**	E **2016** **Actual**	F **2017** **Actual**	G **2018** **Actual**	H **2019** **Actual**	I **2020** **Actual**	J **2021** **Actual**	K **2022** **Bridge**	L **2023** **Test**
1	Change in AD	(1,046)	(1,010)	(966)	(1,016)	(1,092)	(1,102)	(1,333)	(1,446)	(1,529)	(1,644)	(1,840)
2	Less:											
3	*Vehicle Amortization*	(196)	(220)	(232)	(225)	(228)	(246)	(232)	(249)	(271)	(303)	(356)
4	*Deferred Revenue*	-	-	17	46	72	85	102	122	145	173	204
5	**Depreciation Expense**	**(850)**	**(790)**	**(751)**	**(837)**	**(936)**	**(941)**	**(1,203)**	**(1,319)**	**(1,404)**	**(1,514)**	**(1,688)**

ONTARIO ENERGY BOARD

IN THE MATTER OF an application made by the Town of Collingwood for leave to purchase 50% of the issued and outstanding shares of Collingwood PowerStream Utility Services Corp. from Alectra Utilities Corporation, made pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998* (the "**Phase 1 Acquisition**").

IN THE MATTER OF an application made by EPCOR Collingwood Distribution Corp. for leave to purchase all of the issued and outstanding shares of Collingwood PowerStream Utility Services Corp. from the Town of Collingwood, made pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998* (the "**Phase 2 Acquisition**").

IN THE MATTER OF an application made by Collus PowerStream Corp., to be effective following the receipt of Phase 1 Acquisition approval from the Board, seeking to include a negative rate rider in the 2017 Board approved rate schedules of Collus PowerStream Corp. to give effect to a 1% reduction relative to 2017 base residential distribution rates (exclusive of rate riders), made pursuant to section 78 of the *Ontario Energy Board Act, 1998.*

generated by the Solar PV Property is sold to the IESO under its Feed-in-Tariff long-term power purchase agreements.

- Alectra Utilities holds a 50% interest in CollusHoldco, a holding company that wholly owns, among other corporations, CollusLDC, the licensed electricity distributor that owns and is responsible for the operation, maintenance and management of the assets associated with the distribution of electrical power and energy in Collingwood, Stayner, Creemore and Thornbury, pursuant to Distribution Licence ED-2002-0518. The other 50% of CollusHoldco is owned by Collingwood. The other corporations owned by CollusHoldco are Collus PowerStream Energy Corp., a non-operating retail company that was established during the corporatization of the public utilities, and Collus PowerStream Solutions Corp., which provided supervisory, operational, engineering, finance and administrative services.

EPCOR

EPCOR is an Ontario corporation. On the successful approval of the acquisition of CollusHoldco, EPCOR will carry on and continue the business of CollusLDC. EPCOR is an indirect subsidiary of EUI. Schedule B to this application sets out EPCOR's corporate structure.

If the proposed transaction is successful, EPCOR Natural Gas Limited Partnership and its general partner, EPCOR Ontario Utilities Inc. will be affiliates of CollusLDC.

EUI is a corporation incorporated under the laws of the Province of Alberta and is wholly owned by the City of Edmonton, with its head office located in Edmonton, Alberta. EUI, through its (wholly-owned) subsidiaries, builds, owns and operates electrical, natural gas and water transmission and distribution networks, water and wastewater treatment facilities, sanitary and stormwater systems, and infrastructure in Canada and the United States. The company also provides electricity, natural gas and water products and services to residential and commercial customers.

EUI operates its electricity distribution and transmission, water services, energy services (retail energy supply) and corporate business segments through sister corporate subsidiaries. This organizational structure allows EUI to separate its regulated business segments from each other as well as from its non-regulated business segments. This allows EUI to meet the differing regulatory requirements that its regulated businesses are subject to and also ensures that the liabilities and obligations of one business segment or subsidiary do not adversely affect another.

EUI's electricity distribution and transmission businesses own and operate high voltage substations and transmission lines situated within and around Edmonton, Alberta, and form part of the Alberta Interconnected Electric System ("**AIES**") power grid. The 2016 rate base of these businesses is $1.659 billion. Through these facilities, EUI's businesses provide transmission services to the Alberta Electric System Operator ("**AESO**"), the independent not-for-profit entity that is charged with ensuring the efficient operation and expansion of the Alberta transmission grid. EUI's businesses own and operate 72 kV, 138 kV, 240 kV and 500 kV lines and cables, as well as 30 transmission substations, and operate approximately 257 circuit kilometers of aerial transmission lines and underground transmission cables. EUI's businesses also own and operate aerial and underground distribution lines and related facilities operating at 5kV, 15kV and 25kV for the distribution of power to customers within the City of Edmonton, including five distribution substations, 286 distribution feeders, approximately 5,718 circuit kilometers of primary distribution lines, and advanced metering infrastructure (i.e., "Smart Meters"). In 2016, EUI's electricity business distributed approximately 13% of Alberta's provincial energy consumption to approximately 352,853 residential and 36,935 commercial and industrial customer sites in Edmonton.

EUI provides water and wastewater services to more than 1.9 million people in over 85 communities in Western Canada. In conjunction with some of these services, EUI also provides financing and construction services to municipal and industrial customers in Western Canada. Within the City of Edmonton, EUI's system includes approximately 3,900 km of distribution and transmission mains, 19,800 hydrants, 62,000 valves and 12 reservoir sites. In Edmonton and surrounding areas, EUI's businesses service a population of over 800,000 and deliver bulk water to over 65 communities and counties. EUI's businesses own one and operate 33 water or wastewater treatment/distribution facilities outside Edmonton in Alberta, British Columbia, and Saskatchewan.

In addition, EUI's businesses provide water, wastewater, and natural gas distribution services to more than 360,000 customers in three states (Arizona, New Mexico and Texas), 37 communities, and 15 counties in the Southwestern U.S. EUI has also recently purchased a pipeline entering into the business of transporting water to the water scarce region of the State of Texas.

EUI's energy services business procures electricity for its Regulated Rate Option and default supply customers in Alberta and provides customer care and billing services to its customers, and certain customer care and billing services to affiliates and third parties. The energy services business also sells electricity and natural gas to Alberta consumers under competitive contracts through its Encor brand. EUI provides billing and customer care services to approximately 640,000 energy and natural gas customer sites and 265,000 water customer sites in Alberta.

In its various business units (electricity distribution and transmission; water treatment and distribution; natural gas distribution; and energy services), EUI's customers number in the hundreds of thousands and enjoy service quality and reliability well in excess of regulatory requirements and industry standards. EUI has been recognized for more than a decade as one of Alberta's and Canada's best employers and corporate citizens, and intends to bring its expertise and reputation for quality to the Ontario market. Details of EUI's corporate profile, major operations and corporate finances are provided in EUI's July 2017 Investor Presentation, a copy of which is attached as Schedule C.

EUI demonstrates its commitment to providing a safe, healthy workplace through its health and safety policy and programs which focus on leading indicators such as near miss reporting, workplace inspections and audits to assist employees in identifying hazards. A number of EUI's businesses or facilities have been recognized for their safety standards, including in its electrical distribution and transmission businesses which were recipients of the CEA 2017 President's Award of Excellence for Employee Safety. In 2015 and 2016, EUI's electricity distribution and transmission businesses had a Lost Time Injury Frequency ("**LTIF**") of 0.13 and 0.00 respectively, which is well below the average of 0.24 reported by the Canadian Electricity Association for electricity businesses of a similar size. EUI and its predecessors, through their subsidiaries, have provided reliable utility service for over 125 years, consistently meeting and exceeding service quality and safety metrics in the areas served.

EUI has extensive experience integrating and supporting utility businesses as a result of its expansion over the years. The most recent example is EPCOR Natural Gas Limited Partnership's (a subsidiary of EUI) 2017 purchase of the gas distribution system of Natural Resource Gas Limited ("NRG"), a natural gas distributor in Ontario. This experience will be applied to review the processes and technology of CollusLDC in the context of EUI's experience and skills. This will support the efficient and effective integration of targeted functions of CollusLDC's business with EUI, ensuring processes are in place to enable knowledge transfer as well as the provision of targeted administrative services and executive oversight.

9.2 Geographic territory served by each of the parties to the proposed transaction

CollusLDC

A map of CollusLDC's service areas is described below in Figure 4.

Neighbouring utilities include:

Hydro One Networks Inc.

483 Bay Street

EPCOR has reviewed the existing Distribution System Plan published by CollusLDC and believes it to be reasonable. However, because the proposed transaction does not contemplate a physical consolidation, EPCOR is not expecting to generate any substantial capital savings relative to that of the current Distribution System Plan.

Table 3 illustrates the projected cost savings from this transaction.

Table 3: Year over year comparative cost structure ($ thousands)

$000's CAD		Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Year 6 2024
OM&A							
	Status Quo Forecast	5,331	5,425	5,520	5,616	5,752	5,814
	EPCOR Forecast*	5,872	5,191	5,110	5,189	5,306	5,350
	Projected Savings	-541	234	409	427	446	464
Capital							
	Status Quo Forecast**	3,256	3,312	3,303	3,246	3,303	3,361
	EPCOR Forecast	3,256	3,312	3,303	3,246	3,303	3,361
	Projected Savings	0	0	0	0	0	0

** includes transaction and integration costs in 2019 only*

*** CollusLDC Distribution System Plan 2017 – 2022. Years 5 and 6 of the forecast is prior year plus 1.75% inflation*

As published in the 2016 Yearbook of Electricity Distributors, CollusLDC's OM&A cost per connection is $291.78. Because no physical consolidation is contemplated in the proposed transaction, this metric will only change as a result of the synergies achieved.

Rate-setting in Years 1 – 5 of the Deferred Rebasing Period

EPCOR is proposing that all CollusLDC customers will have rates adjusted for the first five years following the closing of the proposed transactions based on the Price Cap Incentive Rate-setting adjustment mechanism.

EPCOR is also requesting Board approval to implement a negative rate rider for residential customers, the effect of which would be an immediate 1% reduction of residential customer's base distribution delivery rates[4]. Following the closing of the proposed transactions the negative rate rider would be effective for years 1 through 5 at which time it would be discontinued. The cost of this rate rider is expected to be approximately $50,000 per year and EPCOR will not seek to recover this in future rates.

In addition, during this initial five year period following closing, CollusLDC's residential distribution rates will continue to be adjusted to move to a fully fixed distribution charge, per OEB Policy "A New Distribution Rate Design for Residential Customers" (EB-2012-0410). In EB-2015-0062, the OEB approved a four-year transition period for CollusLDC customers to move to fixed rates, beginning in 2016.

For the period after the five year deferred rebasing EPCOR will file a cost of service rate application to support the revenue requirement of the utility. When this rebasing application is filed EPCOR forecasts that rate payers will see a net benefit as the cost structure, and therefore revenue requirement, post-transaction is less than that of the status quo by$464,000/year.

10.2 Impact with respect to the adequacy, reliability and quality of electricity service

EPCOR expects to maintain or improve existing CollusLDC service levels and quality standards for CollusLDC's customers.

Table 4 below identifies the SAIDI and SAIFI metrics over the last five years for CollusLDC's system. This table highlights that the CollusLDC system has historically been achieving acceptable levels of reliability. The values increased for 2015 and 2016 as the result of a major project initiated by Bell Canada who has been installing Bell Fibre throughout CollusLDC's service territory. This project was completed in 2017. As detailed above, EPCOR is committed to retaining all CollusLDC staff members and strengthening the existing level of operational capability in the communities serviced by CollusLDC through knowledge transfer from EUI. By retaining CollusLDC employees who are familiar with the territory and the system they service, the utility is positioned to address any reliability concerns that may exist subsequent to the completion of the Bell project. This will enable the utility to work to provide service levels and quality standards that meet or exceed the target for CollusLDC's service territory.

[4] A negative rate rider will result in a 1% reduction of base delivery rates as approved by the OEB in EB-2016-0064. For additional clarity, this rate rider would not apply to any rate riders in effect during the five year deferred rebasing period.

Table 4: CollusLDC's Reliability Metrics

	2012	2013	2014	2015	2016
Duration (SAIDI)	0.51	0.1	0.03	2.36	1.54
Frequency (SAIFI)	0.21	0.73	0.63	0.88	0.84

Figure 8 and Figure 9 below detail EUI's SAIDI and SAIFI metrics over the last five years. While the SAIDI and SAIFI values of EUI's system are not directly comparable to CollusLDC's due to a number of system differences including system size, the length and number of customers on distribution feeders, response times related to size and congestion, and that EUI's system includes rural aerial 25kV feeders that are quite long for an urban environment. However, a comparison between EUI's reliability metrics and the average of the 10 largest systems in Ontario is instructive and demonstrates that EUI has the expertise and experience to operate an electrical distribution system at high service levels.

Figure 8: Comparison of EUI and Ontario LDC SAIDI Metrics

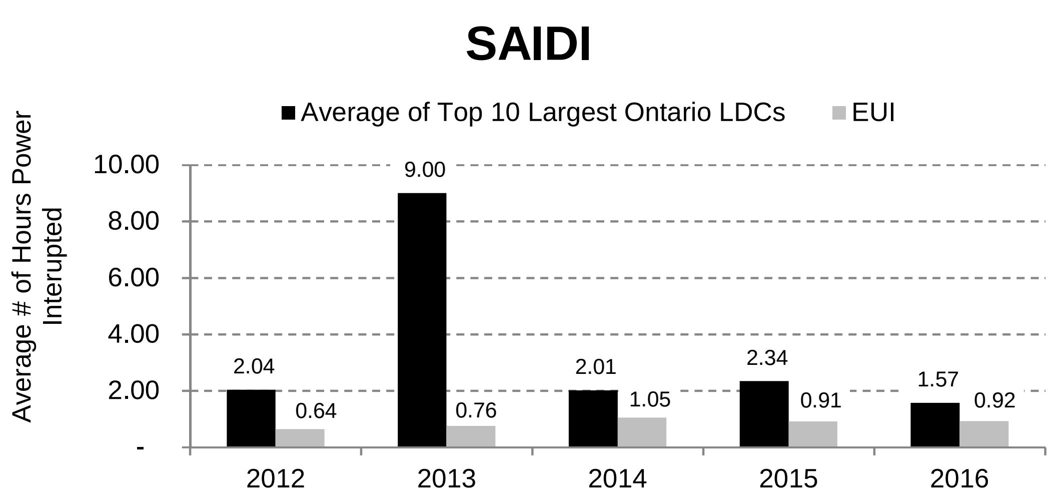
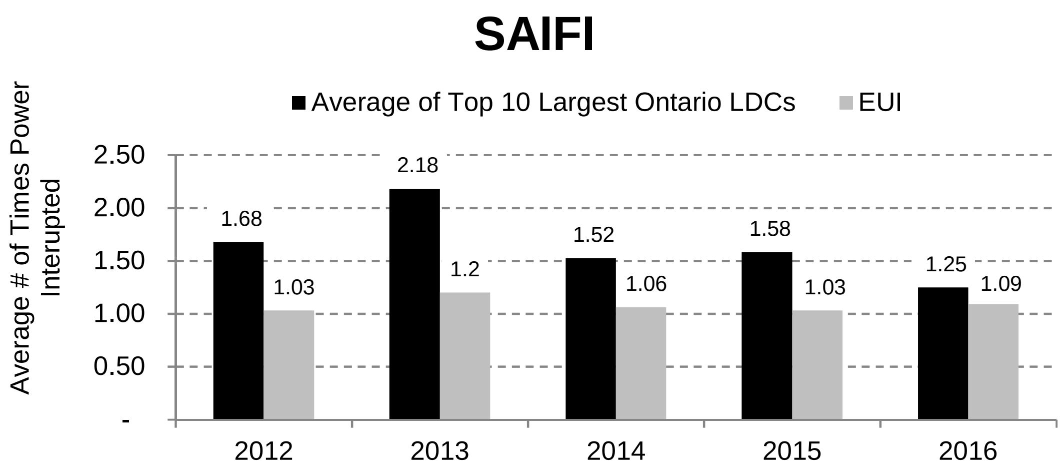


Figure 9: Comparison of EUI's and Ontario LDC SAIFI Metrics



As stated above, in addition to retaining local operating expertise, EPCOR will access the operating expertise developed by EUI that supports the service levels as detailed in the Figures above. This includes EUI's experience with advanced asset management techniques such as Computerized Maintenance Management / Work Management System (CMMS) that are integrated with periodic visual inspection regimes. This allows EUI to actively monitor the condition of assets, perform condition based maintenance and refurbish equipment, or replace deteriorating assets on an as-needed basis, thus planning and organizing the level of maintenance required to ensure ongoing reliable utility performance. EUI also has a dedicated Project Management Office whose experienced staff have comprehensive project management experience completing a wide range of project sizes and types and will share this experience with EPCOR.

Above-standard Customer Service

CollusLDC and EPCOR each have programs that support customer service levels which exceed the targets as established by their respective regulators. EPCOR expects to maintain or improve CollusLDC's existing customer service quality and satisfaction standards. This will be accomplished first by the above referenced retention of existing CollusLDC staff and secondly through ongoing knowledge transfer between EUI and CollusLDC.

Some of the service quality metrics that EPCOR and CollusLDC are measured against are comparable. As an example, in 2016, EUI's distribution business energized 27,835 sites, taking an average 2.3 days from the creation date of the energization service order. This is materially under the timeline of five days included in the OEB's Distribution System Code.

As to customer satisfaction performance metrics, in 2016 EUI exceeded the target of 75% for each of the metrics established by its regulator, the Alberta Utilities Commission. Results are established through an independent survey conducted by Leger Marketing. This includes the following performance measures.

Table 5: EUI Performance Measures

Performance Measure	EUI 2016 Actual
Provides reliable electricity	95.0%
Provides good service to their customers	88.3%
Has a good reputation in the community	84.8%

While the customer satisfaction metrics that EUI is measured against are similar but not directly comparable to those established by the OEB, the superior results achieved by EUI do demonstrate that EPCOR has a history of, and the capability to operate an electrical distribution company in a manner that exceeds expectations. This extends to quality performance metrics measuring billing performance. In 2016 EUI billed 99.999% of sites within 8 business days which exceeded the AUC target of 95% and exceeded the bill completeness target with results of 99.995% versus the target of 98%.

10.3 Describe how the distribution systems within the service areas will be operated, including whether the proposed transaction will cause a change of control

Following OEB approval of the transaction, EPCOR intends to acquire 100% of the shares of CollusHoldco, the parent company of CollusLDC. As EPCOR does not currently own an electrical distribution company in Ontario, EPCOR will not be physically consolidating the CollusLDC system with another distribution system. As a result, the distribution system will continue to be owned by CollusLDC. Only the parent company, CollusHoldco will be subject to a change in control. See Figure 3: Phase 2 Acquisition for a diagram of this transaction.

EPCOR will maintain a head office in Collingwood for CollusLDC as per Section 58.1 of the OEB Act. To support the ongoing operations of CollusLDC, EPCOR has committed to retain all current CollusLDC staff for a period of two years. As EPCOR does not currently own an electrical distribution company in Ontario it expects to retain current employees for a period exceeding the two year contractual commitment. This will allow EPCOR to retain the local knowledge of operating and administrative staff and operate the system in a manner that is expected to maintain

1-Staff-1

Ref: Application, p. 31

The proposed transaction is expected to result in reductions in operating, maintenance and administration (OM&A) costs. Table 3 sets out the EPCOR Collingwood Distribution Corp.'s (EPCOR) projected cost savings on a yearly basis for the five years following the closing of the transaction. The projected savings are shown as the difference in costs between the status quo forecast, i.e., in the absence of the transaction and EPCOR's forecast, post transaction.

a) Please identify the specific areas of the distribution business where the projected cost savings are expected to be generated as a result of the proposed transaction.

b) Please provide a breakdown of the costs by the identified business areas in a) which explains the difference between the status quo forecast and EPCOR's forecast.

c) Please explain what assumptions have been made by the applicants with respect to the expected cost savings.

d) Please identify risks that could negatively impact the projected cost savings, setting out the projected savings if those risks materialize.

Response:

a) The specific areas of the distribution business where the projected cost savings are expected to be generated include Leadership, Operations, Finance, Regulatory, IT and Shared Services.

In addition to these identified efficiencies, EPCOR Collingwood Distribution Corp. ("EPCOR") expects over the long-term, that it will be able to leverage efficiencies gained through EPCOR Utility Inc.'s ("EUI") extensive experiences operating utilities across North America that may further lower the cost structure of the utility relative to the status quo. These future cost savings would be over and above the projected cost savings presented in the application.

b) A breakdown of the net efficiencies by business area is as follows:

$000's CAD	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Year 6 2024
Leadership	-149	-151	-154	-157	-159	-162
Operations & HR	-117	-119	-320	-325	-331	-337
Finance & Regulatory	-125	-127	-129	-132	-134	-136
IT	-142	-145	-147	-150	-152	-155
Shared Services Provided by Affiliates	314	308	341	336	331	326
Transaction Costs	760	0	0	0	0	0
Total	541	-234	-409	-427	-446	-464
Cost of 1% Rate Rider	48	49	51	52	54	0
Total	589	-185	-358	-375	-392	-464

c) **Assumptions**

General Assumptions

Future changes to regulation, legislation, standards, or industry best practices could impact costs. EPCOR assumes that any such changes would impact the Status Quo and the EPCOR forecast equally. This has the effect of preserving the identified efficiencies which are relative to the Status Quo.

Once acquired by EPCOR all services provided to Collus PowerStream Corp. ("EPCOR LDC")[1] by EPCOR affiliates will be performed in accordance with ARC and other applicable regulations and legislation.

All services provided by EPCOR LDC to EPCOR affiliates will be performed in accordance with ARC and other applicable regulations and legislation.

Leadership Assumptions

Board Costs: CollusLDC currently has six directors, two of which are independent and are compensated directly by the utility. Following close of the proposed transaction, EPCOR LDC proposes to have three directors, one of which will be independent and compensated by the utility.

CEO: CollusLDC has been without a CEO since mid-2016. While the position is critical to the ongoing health of the utility, hiring of a new CEO was delayed as a result of the

[1] As detailed in Schedule B of the Application, once acquired by EPCOR, the name of Collus PowerStream Corp. will be amended through the Ontario corporate registry to reflect EPCOR's ownership and it the entity will be EPCOR Collingwood Local Distribution Corp. In these responses, the term EPCOR LDC refers to Collus PowerStream Corp. after its acquisition by EPCOR.

anticipated changes to the ownership of the entity. If CollusLDC were to remain a standalone entity it is understood that a CEO would be hired.

The new CEO for EPCOR LDC will have responsibility for all of EUI's operations in Ontario. The costs of this position will therefore be allocated across EUI's Ontario businesses on a full-cost basis and in accordance with ARC regulations. Sharing this cost across EUI's other Ontario business reduces the cost to CollusLDC that otherwise would have incurred the entire cost of this position.

Operations & HR Assumptions

EPCOR understands that two senior CollusLDC Managers are eligible to retire within two years following close of the pending transaction. The current intent is that these positions will not be filled following retirement. Efficiencies resulting from this include the following.

A number of the responsibilities of the CEO currently delegated to these two senior managers will revert to the new CEO.

Additionally, following close, IT oversight will be provided by EUI's corporate IT group.

Following close, the HR function will be provided by an affiliate of EPCOR through a service level agreement. The HR Manager will report into this affiliate but remain an embedded resource within EPCOR LDC. Following retirement of the senior manager responsible for this function, the EPCOR affiliate will continue providing this service using its existing pool of resources. The fully allocated cost of providing HR services to EPCOR LDC from the affiliate produces additional savings of relative to the Status Quo forecast.

Finance & Regulatory Assumptions

Following close, responsibilities of the CEO currently delegated to the CFO will revert to the new CEO.

The CFO and Regulatory Manager will have responsibility for assisting other EUI subsidiaries in Ontario. Time spent on businesses other than the utility will be tracked and charged at full-cost and in compliance with all ARC regulations. As CollusLDC would have otherwise incurred the entire cost of these positions, sharing these costs across EUI's other Ontario subsidiaries will reduce the costs to EPCOR LDC relative to the Status Quo.

EPCOR will upgrade existing financial systems and processes used by CollusLDC to increase efficiency and free up time for designated staff to provide services to EPCOR affiliates. As an example, an automated time-card process will be implemented that will reduce the time currently spent manually processing time-cards.

Insurance: EPCOR LDC's cost of insurance will be less than what the utility currently pays as coverage from EUI's existing insurance program will be extended to the utility.

IT Assumptions

EUI is able to generate economies of scale within its IT Corporate Service group by servicing multiple business units. Efficiencies will achieved by having existing CollusLDC IT resources report through this corporate group. As part of the Corporate IT group their time and cost will be shared amongst EUI's other businesses through a combination of directly assignable and allocable costs. Because of the virtual nature of IT, there is no need to physically relocate these individuals.

Shared Services Provided by Affiliates

At close, EPCOR affiliates will either replace or supplement services related to the following functions of the utility:

- Legal;
- Health & Safety;
- Training;
- Environmental;
- Public & Government Affairs; and
- Supply Chain

For the most part CollusLDC either outsources these functions or has allocated responsibility for them across a number of individuals. EPCOR LDC will reduce costs by accessing in-house EUI resources for functions that are currently outsourced including Legal and components of Health & Safety and Public & Government Affairs. EPCOR expects to realize cost savings by using internal resources to provide these services.

Responsibility for the remaining functions is generally distributed across existing staff including management of the utility, that have varying levels of expertise and/or availability given their core responsibilities. Having these services provided by an affiliate resource that specializes in the area allows existing staff to focus on their core responsibilities, frees up some of their time and increases the likelihood that forecast efficiencies are achieved.

Transaction Cost Assumptions

While included in Table 3 for completeness, these costs will be recorded in an affiliate of EUI and not EPCOR LDC. These costs will not be charged to the utility.

d) Risks

Leadership Risks

Board: EPCOR is aware of the guidance of the Board proposed in the draft Report of the Board in EB-2014-0255 dated March 28, 2018. Should this guidance become regulation, this could reduce the efficiencies relative to the Status Quo forecast. This is based on the assumption that the costs under Status Quo forecast would increase by one extra independent director, while EPCOR LDC’s costs would increase by two independent directors.

Operations & HR Risks

The primary risk is the timing of when these individuals choose to retire versus EPCOR’s assumption that they will both retire within two years following close. The cost difference will be limited to the salary of the individual for the time differential.

Finance & Regulatory Risks

EPCOR’s ability to achieve synergies by charging portions of the costs of these resources for time spent working on EUI’s other Ontario business is dependent on ensuring that they have the time available to do so. This risk is mitigated through the implementation of systems and processes meant to increase efficiency as well as outsourcing non-core responsibilities to affiliates.

EPCOR is comfortable that over the long-term these savings will be achieved. However, there is a risk that in the first year or two following close of the proposed transaction there may be less time available to spend providing the identified services to affiliates if implementing these systems and processes takes longer than anticipated.

IT Risks

The underlying cost of providing IT to EPCOR LDC is predicated on the status-quo needs of the business. The savings identified are based on a forecast using the utility’s 2018 budget as a starting point. The needs of the business may be materially impacted by changes in law, regulation, standards, and industry best practices. However, the impact of these types of changes is independent of the transaction and will be similar under both the status quo and EPCOR forecasts, with EPCOR potentially having a greater ability to mitigate the costs of unforeseen changes due to the economies inherit in its shared services structure.

If there’s more IT support required than expected for an organization of this size and complexity then it’s possible that not all of the efficiencies identified will be realized.

Risks Summarized

The following table quantifies the impact of incurring each of the risks identified above on the proposed cost savings relative to the Status Quo forecast.

$000's CAD	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Year 6 2024
Leadership	-119	-121	-123	-125	-127	-130
Operations & HR	54	55	-320	-325	-331	-337
Finance & Regulatory	40	-43	-129	-132	-134	-136
IT	-39	-39	-40	-41	-41	-42
Shared Services Provided by Affiliates	314	308	341	336	331	326
Transaction Costs	760	0	0	0	0	0
Total	1,010	160	-271	-286	-303	-318
Cost of 1% Rate Rider	48	49	51	52	54	0
Total	1,058	209	-220	-234	-249	-318

EPCOR considers this to be the worst case scenario and to be an extremely unlikely outcome. The potential of any one of the scenarios underlying each risk taking place is considered modest. Incurring the costs of all of the risks is significantly less likely. This worst case scenario still identifies a net savings of $318k by year 6 following the transaction.

Furthermore, this outcome does not consider the potential for additional savings that might be gained through EUI's extensive experiences operating utilities across North America but that have not yet been identified. These future cost savings would be over and above the projected cost savings presented in the application.

EPCOR Electricity Distribution Ontario Inc.

2019 – 2023 Distribution System Plan

August 26, 2019 – Ver. 3.3

	2019	2020	2021	2022	2023
System Access	$ 311,957	$ 517,226	$ 353,820	$ 361,475	$ 390,582
System Renewal	$ 2,117,880	$ 2,449,813	$ 2,374,029	$ 2,881,046	$ 2,865,186
System Services	$ 300,000	$ 75,000	$ 76,875	$ 79,181	$ 81,161
General Plant	$ 569,210	$ 657,757	$ 585,755	$ 263,809	$ 567,904
Total	$ 3,299,047	$ 3,699,796	$ 3,390,479	$ 3,585,511	$ 3,904,833

	2019	2020	2021	2022	2023
System Access	9%	14%	10%	10%	10%
System Renewal	64%	66%	70%	80%	73%
System Services	9%	2%	2%	2%	2%
General Plant	17%	18%	17%	7%	15%
Total	100%	100%	100%	100%	100%

Table 1 – EEDO Capital Investment Summary 2019 - 2023

5.2.1 Distribution System Plan overview

5.2.1a Key elements of the Distribution System Plan

It is expected that the operational and service requirements driving EEDO's capital expenditures, and found within its DSP, will generally remain consistent through the 2019 to 2023 planning window. EEDO's net total capital expenditure over the planning period 2019 through 2023 is forecasted to be $17.9 million, which reflects average annual spends of $3.6 million in 2019 through 2023. The projected expenditures for 2019 and going forward reflect:

- System Access spending to accommodate connections and road authority work;
- Focused planned capital System Renewal investments required to continue replacing aging assets found in EEDO's distribution system;
- System Service spending needs to facilitate the replacement of the SCADA system in 2019 and ongoing SCADA servicing needs through 2023;
- General plant spending focused on financial/customer software, hardware, tools and staged replacement of fleet units that are reaching economic end-of-life status over the 2019 – 2023 planning window.
- Rising costs, compared to historical values, due to the impact of the decreasing value of the Canadian dollar on procurement of supplies, services and equipment from sources outside of Canada (e.g. fleet vehicles)

There are a number of key elements that contribute to the determination of the planning investments through the period of the DSP:

Ontario Places to Grow Act (2005)/ Growth Plan for the Greater Golden Horseshoe Area (2017) The Growth Plan for the Greater Golden Horseshoe (2017) replaces the 2006 initial Growth Plan and came into effect July 1, 2017. The plan provides population and employment forecasts for the Greater Golden Horseshoe to 2041. Amendments to the Growth Plan in 2018 are not seen as affecting the impact of the 2017 plan on the DSP.

The Town of Collingwood has been identified as a Settlement Area in the Growth Plan for the Greater Golden Horseshoe Area. Growth will be directed to Settlement Areas to make better use of land and infrastructure. The Simcoe Sub-Area is specifically noted in the Growth Plan. It provides additional, more

Projects	2014	2015	2016	2017	2018 Bridge Year	2019 Test Year
General Plant						
Computer Hardware						
	$3,654	$53,754	$61,921	$8,527	$8,243	$50,950
Sub-Total	$3,654	$53,754	$61,921	$11,037	$8,243	$50,950
Computer Software						
	$51,314	$12,521	$69,340	$13,999	$8,000	$50,950
Sub-Total	$51,314	$12,521	$69,340	$13,999	$8,000	$50,950
Pole Bunker						
	$0	$0	$0	$0	$0	$175,000
Sub-Total	$0	$0	$0	$0	$0	$175,000
Transportation Equipment						
	$262,918	$39,115	$354,140	$388,939	$113,100	$240,000
Sub-Total	$262,918	$39,115	$354,140	$388,939	$113,100	$240,000
Miscellaneous	$69,182	$25,697	$22,989	$45,218	$9,584	$52,310
Total	**$387,068**	**$131,087**	**$508,390**	**$459,193**	**$138,928**	**$569,210**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets						
Total	**$387,068**	**$131,087**	**$508,390**	**$459,193**	**$138,928**	**$569,210**

Table 48 – Historical spending - Key General Plant investments

5.4.3.1b Impact of system investment on O&M costs 2019 – 2023

EEDO's operations and maintenance strategy is to minimize reactive and emergency-type work through efficient operations and an effective planned maintenance program, including predictive and preventative actions. EEDO's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with EEDO's capital project work so that where maintenance programs have identified matters which require capital investments, EEDO may adjust its capital spending priorities to address those matters.

- Predictive Maintenance - Predictive maintenance activities involve the testing of elements of the distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies are prioritized and addressed within a suitable time frame.
- Preventative Maintenance - Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted switch maintenance. Also included are regular inspection and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition-based methodologies.
- Emergency Maintenance - This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. EEDO constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. EEDO uses PowerAssist and Alectra Control Room operations to contact "on call" lineperson and supervisory staff in the event of service problems outside of normal business hours.
- Service Work - The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by EEDO for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

- Network Control Operations – EEDO maintains a Supervisory Control and Data Acquisition ("SCADA") system.
- Metering - The metering department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes. Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.
- Substation Services - Substation services activities address the maintenance of all equipment at EEDO's 14 substations. This includes both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of EEDO's planned maintenance program (including predictive and preventative actions) for its substations.
- Operations Area - The Operations area coordinates drafting and design services for capital projects and provides distribution system asset information to many departments within EEDO. Engineering costs are allocated to operations, maintenance, capital, and third party receivable accounts based on total labour, truck and material costs. A standard overhead percentage is set at the beginning of the year for all jobs and adjusted to actual at year end.
- Stores/Warehouse - The Stores area is accountable for managing the procurement, control, and movement of materials within EEDO's service centre. This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital and third party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.
- Garage/Transportation Fleet - The Garage and Transportation Fleet area has as one of its objectives keeping maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital and third party receivable accounts based on number of hours used. A standard "cost per hour" is set for all vehicles within the fleet (one rate for passenger vehicles and pickup and another rate for bucket trucks and work platforms).

System investments will result in:

- the addition of incremental plant (e.g. new MS, poles, switchgear, transformers, etc.);
- the relocation/replacement of existing plant (e.g. road widenings);
- the replacement of end of life plant with new plant (e.g. cables, poles, transformers, etc.)
- new/replacement system support expenditures (e.g. fleet, software, etc.)

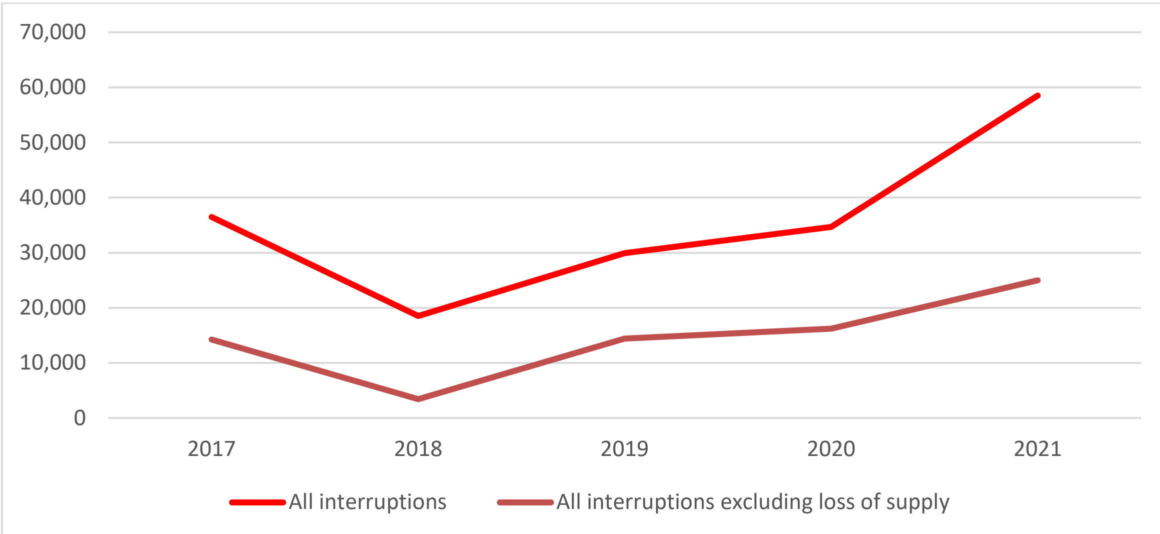
In general, incremental plant additions (e.g. new MS c/w transformer, switchgear, land, etc.) will be integrated into the Asset Management system and will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs. Forecast O&M costs for the 2019 – 2023 period are:

2019	2020	2021	2022	2023
$2,645,000	$2,711,000	$2,856,000	$2,848,000	$2,905,000

Table 49 – 2019 – 2023 O&M projections

Relocation/replacement of existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing O&M purposes (i.e. inspections still need to be carried out on a periodic basis as required per the Distribution System Code). There may be some slight life advantages when a working older piece of equipment is replaced with a newer one that would impact on O&M repair related charges. Overall the plan system investments in this category are expected to put neutral pressure on O&M costs.

2021	58,520	24,994	24,994



2017 – 2021 Interruption history

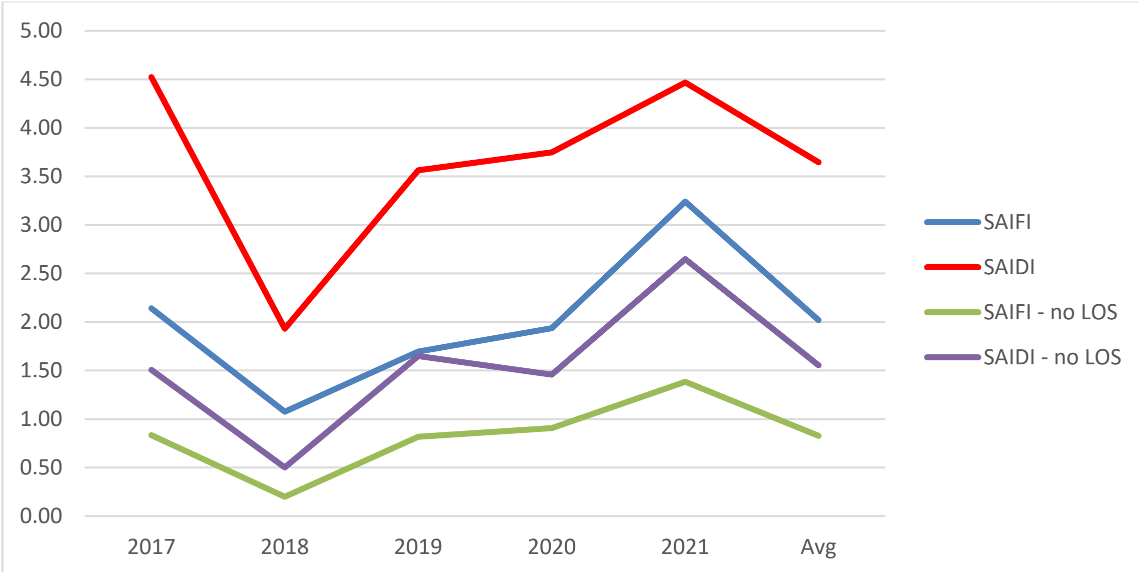
Service reliability statistics are compiled monthly.

The 2017 - 2021 interruption history table shows the significant impact of Loss of Supply and MEDs on overall reliability.

EEDO's SAIFI, SAIDI and CAIDI statistics for the 2017 – 2021 historical period are shown below:

Year	SAIFI	SAIDI	SAIFI - no LOS	SAIDI - no LOS	SAIFI - no LOS, MED	SAIDI - no LOS, MED
2017	2.14	4.52	0.84	1.51	0.84	1.51
2018	1.08	1.93	0.20	0.50	0.20	0.50
2019	1.69	3.56	0.82	1.65	0.82	1.65
2020	1.94	3.75	0.91	1.46	0.91	1.46
2021	3.24	4.47	1.38	2.65	1.38	2.65
Avg	2.02	3.65	0.83	1.55	0.83	1.55

2017 – 2021 Reliability Statistics



2017 - 2021 Reliability statistics – Bulk loss of supply excluded

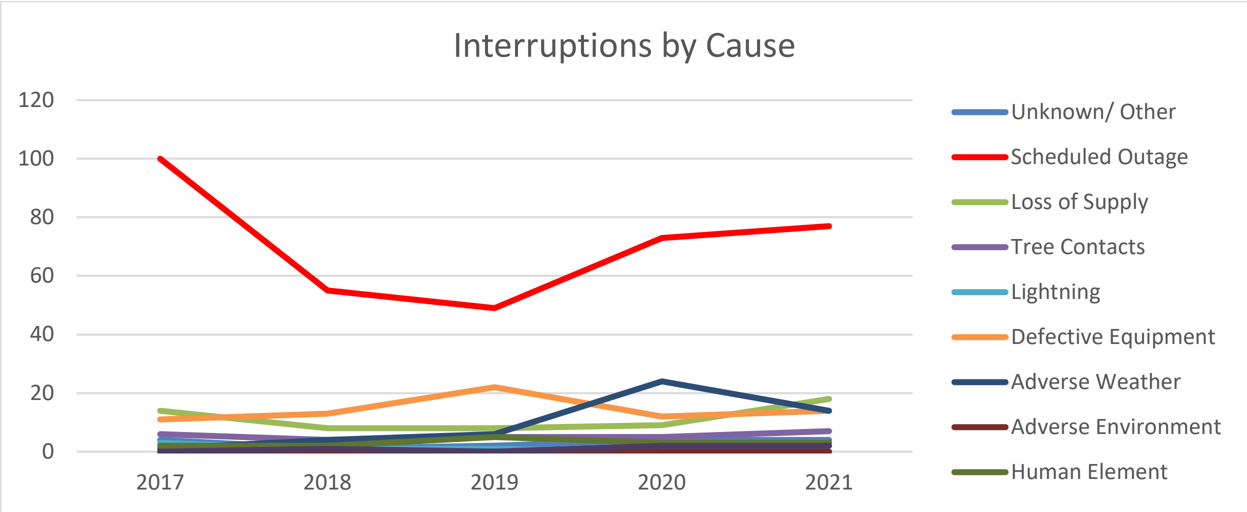
SAIFI (no LOS, no MEDs) has been averaging approximately 0.83 over the historical period. This equates to an EEDO customer experiencing an outage once every 14 months.

SAIDI (no LOS, no MEDs) has been averaging approximately 1.55 over the historical period. This equates to an EEDO average of 93 minutes of outages per customer.

Historical outage causes are listed below:

Code	Primary Cause	2017	2018	2019	2020	2021	Average
0	Unknown/ Other	4	1	2	4	4	3
1	Scheduled Outage	100	55	49	73	77	71
2	Loss of Supply	14	8	8	9	18	11
3	Tree Contacts	6	4	5	5	7	5
4	Lightning	3	1	1	0	0	1
5	Defective Equipment	11	13	22	12	14	14
6	Adverse Weather	1	4	6	24	14	10
7	Adverse Environment	0	0	0	0	0	0
8	Human Element	2	2	5	3	3	3

9	Foreign Interference	0	1	0	2	2	1



2017 - 2021 Reliability statistics – Detail

2021	**Number of Interruptions**	**Customers Affected**	**Customer Hours**	**Average Customers**	**SAIDI**	**SAIFI**	**CAIDI**
Unknown/Other	4	412	328	18,058	0.02	0.02	0.80
Scheduled Outage	77	1,810	5,662	18,058	0.31	0.10	3.13
Loss of Supply	18	33,526	32,881	18,058	1.82	1.86	0.98
Tree Contacts	7	11,082	19,697	18,058	1.09	0.61	1.78
Lightning	-	-	-	18,058	-	-	-
Defective Equipment	14	1,406	1,664	18,058	0.09	0.08	1.18
Adverse Weather	14	10,012	20,354	18,058	1.13	0.55	2.03
Adverse Environment	-	-	-	18,058	-	-	-
Human Element	3	213	29	18,058	0.00	0.01	0.13
Foreign Interference	2	59	87	18,058	0.00	0.00	1.48
Major Event	-	-	-	18,058	-	-	-
Total	**139**	**58,520**	**80,703**	**18,058**	**4.47**	**3.24**	**1.38**

2020	Number of Interruptions	Customers Affected	Customer Hours	Average Customers	SAIDI	SAIFI	CAIDI
Unknown	4	664	163	17,924	0.01	0.04	0.25
Scheduled Outage	73	988	3,546	17,924	0.20	0.06	3.59
Loss of Supply	9	18,441	41,061	17,924	2.29	1.03	2.23
Tree Contacts	5	10,320	14,108	17,924	0.79	0.58	1.37
Lightning	-	-	-	17,924	-	-	-
Defective Equipment	12	324	898	17,924	0.05	0.02	2.77
Adverse Weather	24	2,789	6,880	17,924	0.38	0.16	2.47
Adverse Environment	-	-	-	17,924	-	-	-
Human Element	3	1,146	374	17,924	0.02	0.06	0.33
Foreign Interference	2	15	162	17,924	0.01	0.00	10.79
Major Event	-	-	-	17,924	-	-	-
Total	**132**	**34,687**	**67,192**	**17,924**	**3.75**	**1.94**	**1.94**

2019	Number of Interruptions	Customers Affected	Customer Hours	Average Customers	SAIDI	SAIFI	CAIDI
Unknown	2	119	80	17,670	0.00	0.01	0.67
Scheduled Outage	49	827	2,518	17,670	0.14	0.05	3.04
Loss of Supply	8	15,502	33,792	17,670	1.91	0.88	2.18
Tree Contacts	5	10,004	22,480	17,670	1.27	0.57	2.25
Lightning	1	1	11	17,670	0.00	0.00	10.77
Defective Equipment	22	2,078	2,258	17,670	0.13	0.12	1.09
Adverse Weather	6	101	459	17,670	0.03	0.01	4.54
Adverse Environment	-	-	-	17,670	-	-	-
Human Element	5	1,313	1,355	17,670	0.08	0.07	1.03
Foreign Interference	-	-	-	17,670	-	-	-
Major Event	-	-	-	17,670	-	-	-
Total	**98**	**29,945**	**62,953**	**17,670**	**3.56**	**1.69**	**2.10**

2018	Number of Interruptions	Customers Affected	Customer Hours	Average Customers	SAIDI	SAIFI	CAIDI
Unknown	1	16	3	17,223	0.00	0.00	0.18
Scheduled Outage	55	1,658	16,261	17,223	0.94	0.10	9.81
Loss of Supply	8	15,095	24,627	17,223	1.43	0.88	1.63
Tree Contacts	4	54	126	17,223	0.01	0.00	2.34
Lightning	1	327	196	17,223	0.01	0.02	0.60
Defective Equipment	13	519	720	17,223	0.04	0.03	1.39
Adverse Weather	4	832	1,304	17,223	0.08	0.05	1.57
Adverse Environment	-	-	-	17,223	-	-	-
Human Element	2	15	89	17,223	0.01	0.00	5.96
Foreign Interference	1	8	6	17,223	0.00	0.00	0.78
Major Event	-	-	-	17,223	-	-	-
Total	**89**	**18,524**	**43,333**	**17,223**	**2.52**	**1.08**	**2.34**

2017	Number of Interruptions	Customers Affected	Customer Hours	Average Customers	SAIDI	SAIFI	CAIDI
Unknown	4	51	29	17,022	0.00	0.00	0.57
Scheduled Outage	100	1,151	2,863	17,022	0.17	0.07	2.49
Loss of Supply	14	22,243	51,350	17,022	3.02	1.31	2.31
Tree Contacts	6	9,714	19,832	17,022	1.17	0.57	2.04
Lightning	3	1,968	1,195	17,022	0.07	0.12	0.61
Defective Equipment	11	220	639	17,022	0.04	0.01	2.91
Adverse Weather	1	1,058	1,005	17,022	0.06	0.06	0.95
Adverse Environment	-	-	-	17,022	-	-	-
Human Element	2	58	83	17,022	0.00	0.00	1.43
Foreign Interference	-	-	-	17,022	-	-	-
Major Event	-	-	-	17,022	-	-	-
Total	**141**	**36,463**	**76,996**	**17,022**	**4.52**	**2.14**	**2.11**

Service reliability statistics are compiled monthly.

The 2014 - 2018 interruption history table shows the significant impact of Loss of Supply and MEDs on overall reliability.

EEDO's SAIFI, SAIDI and CAIDI statistics for the 2014 – 2018 historical period are shown below:

Year	SAIFI	SAIDI	SAIFI - no LOS	SAIDI - no LOS	SAIFI - no LOS, MED	SAIDI - no LOS, MED
2014	0.95	0.03	0.63	0.3	0.63	0.3
2015	1.19	2.77	0.88	2.36	0.88	2.36
2016	2.06	5.96	1.66	5.41	0.84	1.54
2017	2.14	4.52	0.84	1.51	0.84	1.51
2018	1.08	1.93	0.2	0.5	0.2	0.5
Avg	1.48	3.04	0.84	2.02	0.68	1.24

Table 14 – 2014 – 2018 Reliability Statistics

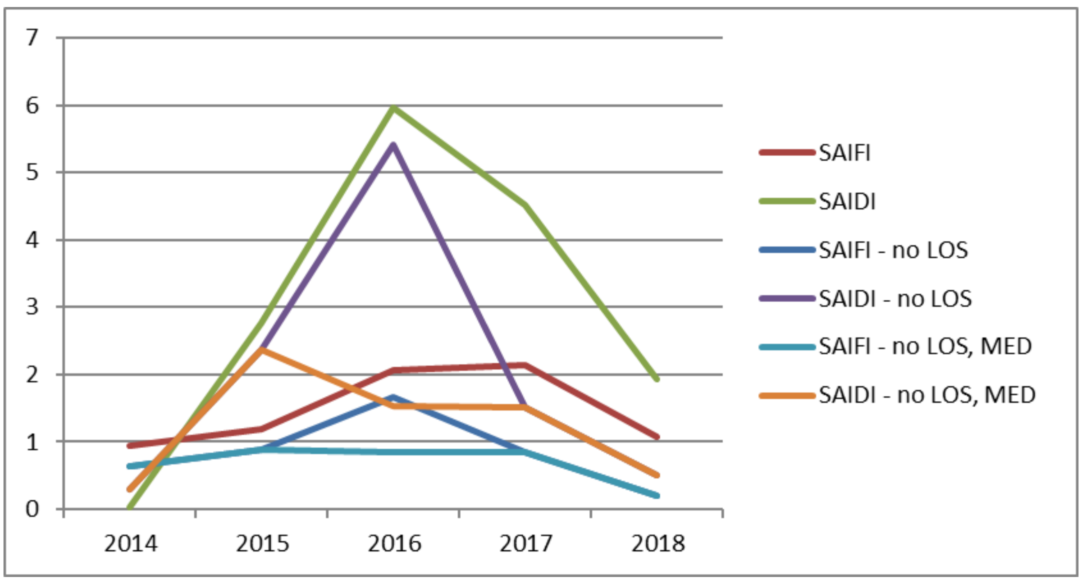


Table 15 – 2014 - 2018 Reliability statistics – Bulk loss of supply excluded

SAIFI (no LOS, no MEDs) has been averaging approximately 0.68 over the historical period. This equates to an EEDO customer experiencing an outage once every 17 months.

SAIDI (no LOS, no MEDs) has been averaging approximately 1.24 over the historical period. This equates to an EEDO average of 74 minutes of outages per customer.

Historical outage causes are listed below:

Code	Primary Cause	2014	2015	2016	2017	2018	Average
0	Unknown/ Other	6	8	0	4	1	4
1	Scheduled Outage	98	176	181	100	55	122
2	Loss of Supply	3	5	9	14	8	8
3	Tree Contacts	8	1	13	6	4	6
4	Lightning	1	0	0	3	1	1
5	Defective Equipment	29	25	34	11	13	22
6	Adverse Weather	9	5	20	1	4	8
7	Adverse Environment	0	0	0	0	0	0
8	Human Element	9	5	6	2	2	5
9	Foreign Interference	3	2	3	0	1	2

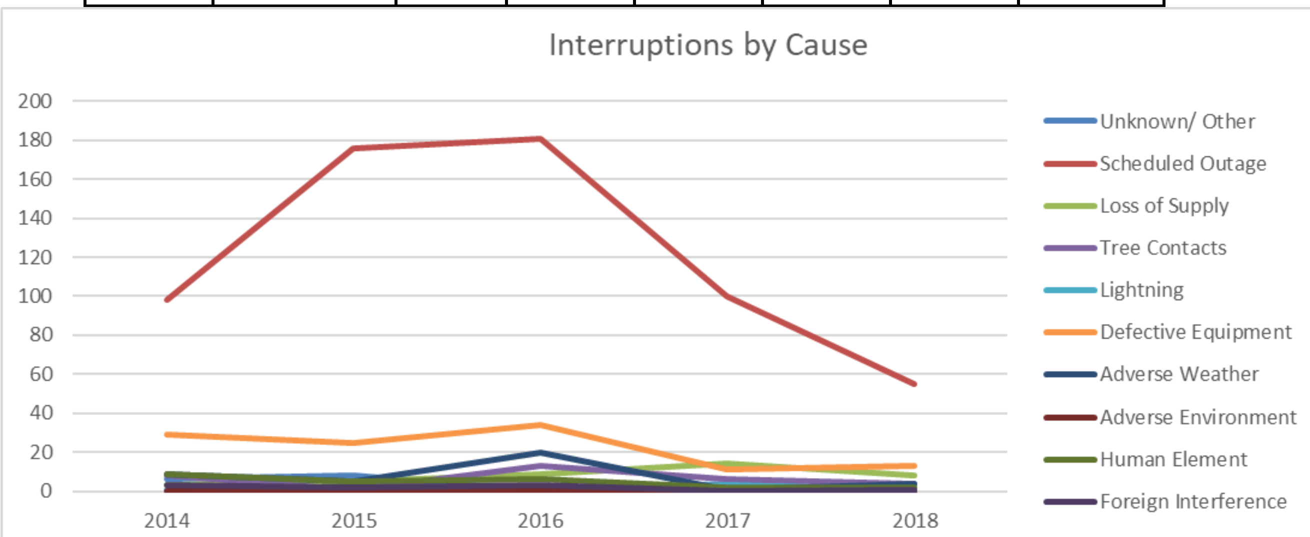


Table 16 – 2014 – 2018 Outage causes

Code 1 outages are high due to need to schedule outages to accommodate significant third party (Bell) pole work in 2015 and 2016.

Code 3 outages, tree contacts, show an oscillating trend. Code 3 outages are mitigated through effective tree trimming programs to maintain line clearance standards.

There are no impacts from this IRRP to EEDO's DSP.

2-SEC-21
[Ex.2, DSP p.13] The DSP states 'When given the option to reduce costs with slight risk to service, maintain status quo or invest slightly more than today for slight improvement, 94% would maintain status quo or higher, with 61% definitively support investing in future improvements.' As part of the Stone Olafson survey, were customers informed of the 20% average distribution rate increase? (Ref: Bill Impacts average of subtotal A impacts).

EEDO Response:

No. Rate impacts were quantified at the time of the survey as the intent of the survey was to gather customer feedback in the development of the distribution system plan.

2-SEC-22
[Ex.2, DSP] In the MAADs application EB-2017-0373/0374, the Applicant committed "to meet or exceed current reliability standards for the next five years" [Application, p. 13]. Table 14 of the 2019-2023 DSP shows the average SAIDI (excluding loss of supply (LOS) and major event days (MED) as 1.24 and SAIFI as 0.68 for the years 2014-2018. These values are carried forward in Table 9 as targets for 2019-2023. In the 2023-2027 DSP on page 18, EEDO has set the same targets. Page 20 shows an average SAIDI of 1.55 and SAIFI of 0.83 for the period 2017-2021.

	Average 2014-2018	Target 2019-2023	Average 2017-2021	Target 2023-2027
SAIDI	1.24	1.24	1.55	1.24
SAIFI	0.68	0.68	0.83	0.68

a) Please explain why EPCOR and EEDO were unable to fulfill the commitment it made in the MAADs application to meet or exceed the current reliability standards.

EEDO Response:

EEDO's operating area has been hit by a large number of storm related events in the years of 2017 to 2021. This was the primary reason for the miss on SAIDI and SAIFI metrics. EEDO made the case in two cases to the OEB to have these events treated as Major Event Days (MED) given the impact to reliability metrics exceeding the MED threshold, and that the storms resulted in a failure of trees that in EEDO's perception were outside of its control through vegetation management. These requests for MED were ultimately denied by the OEB. During the MAAD application, it could not have been foreseen that EEDO would be faced with this type of outage event without the ability to classify as MEDs.

b) Given that EEDO was unable to meet its targeted reliability standards for 2019 to 2023, why does it believe it can meet the same targets for 2023-2027?

EEDO Response:

EEDO has learned from these outage events and the OEB's classification, and is taking measures to better respond to these types of events. The DSP includes plans for fault line indicators and remotely operable switches. The fault line indicators will give EEDO a more accurate location of any fault condition speeding up the response and lessening the need for lengthy line patrols to find issues related to storm caused tree contacts. Remotely operable switches will permit for quicker fault isolation and restoration when a tree has failed and fallen onto the power lines.

2-SEC-23

[Ex.2, DSP, Appendix 2-AB] Appendix 2-AB shows that for 2013 to 2021 EEDO underspent on System Renewal by $4.1M ($18.3M Plan versus $14.2M Actual). On page 20 of the DSP the average SAIFI of 0.83 and SAIDI of 1.55 are above the targets shown on page 18. Please explain the reasons for the under spending and how it has been a factor in EEDO not meeting its target.

EEDO Response:

As noted in EEDO's response to 2-Staff-17, a significant portion of the difference between planned spend and actual is that deferred projects appearing in multiple years' planned budget. The under spend to plan on system renewal has not yet resulted in material reliability impacts (i.e. failed pole lines). This could have resulted in major reliability impacts had an event been large enough to fail a pole line, however, EEDO has been recovering on its uncompleted and carryover capital, ensuring that the priority projects by risk assessment are completed or planned to be complete. This investment continues to be very important to ensure reliability and public safety of our power lines. The primary drivers for the miss on reliability targets is as explained in response to 22 (a), storm related tree contacts.

2-SEC-24

[Ex.2, DPS pp. 51 & 57] The DSP lists one of 3 key drivers of its capital investment as 'planned system renewal spending to proactively replace plant <u>at end of life</u> in order to meet EEDO's commitment to maintain a safe and reliable supply of electricity to its customers.' (Emphasis added). Please reconcile this with the plan to proactively replace poles based on a health condition assessment, not simply by age (page 51).

EEDO Response:

This should have been updated to reflect EEDO's shift towards asset management based on asset condition assessment. Asset age continues to be a driver of asset condition, but it is considered along with other factors determined through inspection, loading assessment, and maintenance.

2-SEC-25

[Ex.2, 2-BA, DSP p. 54] Based on information from 2-BA USoA 2055:

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

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Appendix 2-JA

Summary of Recoverable OM&A Expenses

	2013 Last Rebasing Year OEB Approved	2013 Last Rebasing Year Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Reporting Basis												
Operations	$ 582,100	$ 657,706	$ 706,743	$ 721,686	$ 754,396	$ 886,046	$ 885,794	$ 866,849	$ 1,149,538	$ 1,060,428	$ 1,056,073	$ 977,066
Maintenance	$ 1,490,900	$ 1,395,752	$ 1,462,370	$ 1,667,027	$ 1,727,736	$ 1,303,848	$ 1,424,249	$ 1,391,638	$ 1,636,327	$ 1,391,926	$ 1,382,679	$ 1,640,206
SubTotal	**$ 2,073,000**	**$ 2,053,457**	**$ 2,169,113**	**$ 2,388,712**	**$ 2,482,131**	**$ 2,189,894**	**$ 2,310,043**	**$ 2,258,487**	**$ 2,785,865**	**$ 2,452,353**	**$ 2,438,752**	**$ 2,617,273**
%Change (year over year)		-0.9%	5.6%	10.1%	3.9%	-11.8%	5.5%	-2.2%	23.4%	-12.0%	-0.6%	7.3%
%Change (Test Year vs Last Rebasing Year - Actual)												27.5%
Billing and Collecting	$ 993,862	$ 839,380	$ 809,917	$ 823,062	$ 895,356	$ 974,046	$ 949,464	$ 975,000	$ 1,010,748	$ 985,537	$ 1,087,165	$ 1,109,304
Community Relations	$ 138,000	$ 153,000	$ 161,767	$ 210,766	$ 158,939	$ 225,346	$ 227,791	$ 241,736	$ 239,793	$ 176,984	$ 160,108	$ 188,552
Administrative and General	$ 1,380,298	$ 1,369,268	$ 1,423,503	$ 1,282,167	$ 1,380,719	$ 1,228,690	$ 1,311,958	$ 2,118,937	$ 2,075,033	$ 1,897,222	$ 2,498,636	$ 2,615,186
SubTotal	**$ 2,512,160**	**$ 2,361,648**	**$ 2,395,188**	**$ 2,315,994**	**$ 2,435,015**	**$ 2,428,082**	**$ 2,489,214**	**$ 3,335,673**	**$ 3,325,573**	**$ 3,059,743**	**$ 3,745,909**	**$ 3,913,043**
%Change (year over year)		-6.0%	1.4%	-3.3%	5.1%	-0.3%	2.5%	34.0%	-0.3%	-8.0%	22.4%	4.5%
%Change (Test Year vs Last Rebasing Year - Actual)												65.7%
Total	**$ 4,585,160**	**$ 4,415,105**	**$ 4,564,301**	**$ 4,704,707**	**$ 4,917,146**	**$ 4,617,976**	**$ 4,799,257**	**$ 5,594,161**	**$ 6,111,438**	**$ 5,512,097**	**$ 6,184,661**	**$ 6,530,315**
%Change (year over year)		-3.7%	3.4%	3.1%	4.5%	-6.1%	3.9%	16.6%	9.2%	-9.8%	12.2%	5.6%

	2013 Last Rebasing Year OEB Approved	2013 Last Rebasing Year Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Operations[4]	$ 582,100	$ 657,706	$ 706,743	$ 721,686	$ 754,396	$ 886,046	$ 885,794	$ 866,849	$ 1,149,538	$ 1,060,428	$ 1,056,073	$ 977,066
Maintenance[5]	$ 1,490,900	$ 1,395,752	$ 1,462,370	$ 1,667,027	$ 1,727,736	$ 1,303,848	$ 1,424,249	$ 1,391,638	$ 1,636,327	$ 1,391,926	$ 1,382,679	$ 1,640,206
Billing and Collecting[6]	$ 993,862	$ 839,380	$ 809,917	$ 823,062	$ 895,356	$ 974,046	$ 949,464	$ 975,000	$ 1,010,748	$ 985,537	$ 1,087,165	$ 1,109,304
Community Relations[7]	$ 138,000	$ 153,000	$ 161,767	$ 210,766	$ 158,939	$ 225,346	$ 227,791	$ 241,736	$ 239,793	$ 176,984	$ 160,108	$ 188,552
Administrative and General[8]	$ 1,380,298	$ 1,369,268	$ 1,423,503	$ 1,282,167	$ 1,380,719	$ 1,228,690	$ 1,311,958	$ 2,118,937	$ 2,075,033	$ 1,897,222	$ 2,498,636	$ 2,615,186
Total	**$ 4,585,160**	**$ 4,415,105**	**$ 4,564,301**	**$ 4,704,707**	**$ 4,917,146**	**$ 4,617,976**	**$ 4,799,257**	**$ 5,594,161**	**$ 6,111,438**	**$ 5,512,097**	**$ 6,184,661**	**$ 6,530,315**
%Change (year over year)		-3.7%			4.5%	-6.1%	3.9%	16.6%	9.2%	-9.8%	12.2%	5.6%

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Appendix 2-JB
Recoverable OM&A Cost Driver Table[1,3]

OM&A	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance[2]	$ 4,585,160	$ 4,415,105	$ 4,564,301	$ 4,704,707	$ 4,917,146	$ 4,617,976	$ 4,799,257	$ 5,594,161	$ 6,111,438	$ 5,512,097	$ 6,184,661
Operations	$ 75,606	$ 49,037	$ 14,943	$ 32,710	$ 131,651	-$ 252	-$ 18,945	$ 282,690	-$ 89,111	-$ 4,354	-$ 79,007
Maintenance	-$ 95,148	$ 66,618	$ 204,657	$ 60,709	-$ 423,888	$ 120,402	-$ 32,611	$ 244,689	-$ 244,401	-$ 9,246	$ 257,527
Billing and Collecting	-$ 154,482	-$ 29,462	$ 13,144	$ 72,294	$ 78,690	-$ 24,582	$ 25,536	$ 35,747	-$ 25,211	$ 101,628	$ 22,139
Community Relations	$ 15,000	$ 8,767	$ 48,998	-$ 51,826	$ 66,407	$ 2,445	$ 13,945	-$ 1,944	-$ 62,808	-$ 16,876	$ 28,444
Administrative and General	-$ 11,030	$ 54,235	-$ 141,336	$ 98,552	-$ 152,029	$ 83,268	$ 806,979	-$ 43,904	-$ 177,811	$ 601,414	$ 116,550
Closing Balance[2]	$ 4,415,105	$ 4,564,301	$ 4,704,707	$ 4,917,146	$ 4,617,976	$ 4,799,257	$ 5,594,161	$ 6,111,438	$ 5,512,097	$ 6,184,661	$ 6,530,315

kWh	2023 Weather Normal Forecast	CDM Adjustment	2023 CDM Adjusted Forecast
Residential	137,786,709	140,637	137,646,072
GS < 50	45,560,556	569,114	44,991,441
GS > 50	133,662,788	1,738,246	131,924,542
Street Light	1,242,766		1,242,766
USL	396,233		396,233
Total	318,649,052	2,447,998	316,201,055

4-SEC-32

[Ex.4, 2-JA] As part of the merger application EB-2017-0373/0374, EPCOR provided a forecast of OM&A and Appendix 2-JA includes actual $ for OM&A as follows:

$000	2019	2020	2021	2022	2023	Total
Status Quo Forecast EB-2017-0373/0374 Application p. 30	5,331	5,425	5,520	5,616	5,752	
EPCOR Forecast EB-2017-0373/0374 Application p. 10	5,872	5,191	5,110	5,189	5,306	
Appendix 2-JA Actual	5,594	6,111	5,512	6,166	6,530	
Variance Actual to EPCOR Forecast	(278)	920	402	977	1,224	3,245
Variance Actual to Status Quo	263	686	(8)	550	778	2,269

a) Please explain the reasons for the variance of $3,245k between actuals and the EPCOR Forecast upon which the OEB approved the acquisition of EEDO.

EEDO Response:

In addition to most of the increased costs noted below in the response to b), other reasons for the variance between EPCOR Forecast and Actual costs include:

- The EPCOR Forecast assumed that the CEO position could be replaced with a portion of the Vice President, Ontario Region position and the CEO position could absorb the responsibilities of certain individuals on their retirement. Given the growth of the system and the significant capital and operating programs of EEDO, actuals have required a larger percentage of the VPs time and necessitated adding the services of the Director, Operations Ontario position. Partially offsetting this item, EEDO was able to remove the Mgr, Hydro Services position as a result of having the Director. Operations Ontario position provide EEDO services.
- EPCOR's Forecast included assumptions regarding IT and Finance staff savings through cost splitting with affiliates which did not materialize.

IT and GIS work has continued to be significant with 2 of 3 IT/GIS positions being fully utilized in EEDO Operations. EEDO has been able to move 1 IT position to EOOMI (Manager, Ops Networks) and now less than a full FTE is charged to EEDO with respect to these IT services.

Finance time assumed that the Senior Manager, Financial and Regulatory Reporting could complete work for other Ontario affiliates. This position remains fully consumed providing finance services to EEDO and assisting in providing financial inputs to EEDO's various regulatory filings, especially in light of no longer having a Controller position, which EEDO used to have.

- Higher Corporate Shared Services due to higher costs from adding additional Corporate Services since the forecast was prepared and higher Corporate Costs allocation percentages than contemplated in the original forecast.
- Higher Affiliate Shared Services due to additional services being required for safe and reliable operations of the utility, including additional HSE support, additional Regulatory support and additional Operational support services (provided by EOOMI).

b) Please explain the reasons for the variance of $2,269k between actuals and the EEDO Status quo Forecast.

EEDO Response:

The Status Quo forecast was primarily based on the 2018 Collus PowerStream budget with an annual inflation escalator added each year. EEDO experienced increased costs relative to the status quo forecast due to the following reasons:

- Adding EPCOR Corporate Shared Services and Affiliate shared services for 2018 to 2023.
    - As a result of adding these services, EEDO was able to remove several positions or remove full FTEs to EOOMI, including:
        - Manager, HR (1 FTE)
        - Manager, Ops Network (1 FTE)
        - Manager, Billing (0.5 FTE)
        - Manager, Hydro Services (1 FTE)
    - This is offset by Shared Services provided by Alectra and the Town of Collingwood which have gone away and not have an embedded CEO in EEDO.

- EEDO has worked to revamp how capital is deployed and this has resulted in an increased ability to charge staff costs to capital. In addition, the overhead capitalization procedure was updated. These items resulted in lower OM&A costs.
- Customer growth – The status quo forecast incorporated inflationary growth in costs but did not factor in additional costs from customer growth. And system has continued to grow since acquisition.
- After acquisition EEDO's internal audit performed a review of the EEDO operations were conducted that identified additional issues that required remediation. To remediate these issues additional OM&A costs were incurred in 2020.
- COVID-19 risk mitigations in 2020 – EEDO experienced higher OM&A costs as a result of lower crew capacity to perform capital work.
- Additional operations headcount for an inspector/locator position starting 2019 onwards as work in this area was not being completed in a timely manner.

4-SEC-33

[Ex.4, p.4 & p.10, 2-JA] EEDO states '2019 General & Administrative costs increased relative to 2018 due to having a full year of shared services being provided by EPCOR affiliates' (p.4) and 'However some services were noted that were required to be added to provide safe and reliable services (including for example adding HSE resources) and to complete capital and operating work required for the growing utility system' (p.10). 2-JA shows an increase of approx. 62% in 2019 ($2,119k) over 2018 ($1,312k):

a) Please provide a breakdown of what made up that increase, i.e. how much was increased costs for EPCOR providing the same services as was previous provided by others, versus how much was for new services provided by EPCOR.

EEDO Response:

The increase from 2018 to 2019 is primarily due to a full year of shared service costs from EEDO affiliates in 2019, versus only receiving these services from EEDO affiliates after the EPCOR acquisition in 2018. The response to 4-SEC-34 shows this change - $186k in 2018 to $1,105k (which is $365k plus $740k from the table in the response to 4-SEC-34 below) in 2019. This is $919k of the increase in General & Administrative in 2018A to 2019A.

The increase in shared services is also due to some new services being offered in 2019, as EPCOR took over operations, continued integration and added some new services which did not exist prior to EPCOR acquiring EEDO. EWSI provided significant Supply Chain Management integration services in 2019 related to setting up EEDO in EPCOR's Oracle GL System (see page 63 of Exhibit 4). EOUI added services which the utility required for operations and capital work (HSE and Regulatory support, see page 70 of Exhibit 4).

This difference shared services costs noted above in offset by various other items, including lower contractor usage and lower rent expense.

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EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

SETTLEMENT PROPOSAL

Appendix D – Responses to Pre-Settlement Clarification Questions

with these projects as well due to extra equipment and time that will be required to install port-a-holes and anchors as well as crane rentals for setting poles.

4. [EEDO_2023 Load Forecast_20220825] The Summary Tables show data for 2021 as an estimate. Please update test year forecast with 2021 actuals and based on actual data to end of September 2022, update 2022 forecast as required.

EEDO Response:

Please refer to attachment 3-SEC-4 Updated Load Forecast.

5. [4-SEC-34] With respect to 4-SEC-34:

    a. With respect to the first bullet, for each year between 2019 and 2022, please provide the net cost/savings related to the difference between EEDO forecast and actuals.

EEDO Response:

Please see the table below for the net cost increase attributable to the first bullet point. One clarifying point to add to the explanation in the first bullet point is that the EPCOR Forecast assumed attrition in former the VP Operations position when the employee retired in 2021, instead the Hydro Manager position was removed when the incumbent moved into the VP Operations position when the former VP Operations retired.

	2019	2020	2021	2022
Total	74,539	108,559	147,927	229,816

    b. With respect to the second bullet point, please provide the total amount EEDO spent/forecast to spend on, i) IT/GIS OM&A, ii) finance and regulatory OM&A work, for each year between 2017 and 2023, regardless of how the work was procured (i.e. internal, external, affiliate, corporate etc.).

EEDO Response:

Please see the table below for EEDO spending on

	2017	2018	2019	2020	2021	2022	2023
IT/GIS	222,175	235,440	419,121	395,117	425,528	463,293	512,112
Finance and Regulatory	444,728	554,347	611,989	619,090	607,988	652,652	684,337

With respect to the third bullet point:

i. Please provide the corporate service costs in each year between 2019 and 2023, broken down by, “additional corporate services provided” and “higher allocation percentages as contemplated in the original forecast". Please explain how this breakdown was undertaken.

ii. Please explain what additional corporate services were provided.

EEDO Response:

i. Please see the table below for the 2019 to 2023 difference between forecasted and actual corporate service costs broken out between additional corporate services and higher allocation percentages.

The breakdown was determined by taking the actual additional allocations related to corporate services which were not contemplated in the original forecast and then subtracting this amount from the difference between the actual corporate shared services and the originally forecasted corporate shared services.

Additional costs	2019	2020	2021	2022	2023
Higher allocation percentages	206,617	130,218	195,032	214,279	287,800
Additional corporate services	16,935	25,067	28,615	32,693	32,790
Difference in corporate shared services	223,012	155,285	223,646	246,973	320,590

ii. The following additional corporate services were provided,

a. Learning and Development/Technical Training

b. Organizational Project Management

c. With respect to the fourth bullet, for each year between 2018 and 2023, please provide a breakdown of the listed items.

EEDO Response:

Please see the table below for a breakdown of the yearly difference between actual and forecast for the listed items.

	2018	2019	2020	2021	2022	2023

HSE	-	28,240	31,827	27,790	40,704	39,607
Regulatory	-	11,475	12,533	-	29,179	39,715
Operational support	-	-	57,709	58,186	67,632	67,012
Total	**-**	**39,715**	**102,069**	**85,976**	**137,515**	**146,334**

6. [4-Staff-51] Please provide a copy of the Service Level Agreements that govern recovery of costs for shared and corporate services.

EEDO Response:

Please refer to the .zip file 4-SEC-6 accompanying this submission.

7. Does the EEDO provide services to any its affiliates? If so, please provide details and the amount recovered (or forecast to be recovered) for each year between 2019 and 2023, and how the amounts are reflected in the application.

EEDO Response:

Yes, from 2019 to 2023 services were provided from EEDO to its affiliates ENGLP, EOUI/EOOMI, and EUI. The services include IT, GIS, Regulatory, Engineering and HR support as broken out in the table below.

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
IT	79,076	98,549	88,116	52,977	21,604
GIS/Engineering	5,153	15,129	7,430	7,578	7,730
Regulatory	0	42,218	83,416	85,084	86,786
HR	54,062	-	-	-	-
Total	**138,291**	**155,896**	**178,962**	**145,639**	**116,120**

The cost and FTE relating to the employee time spent providing services to affiliates has not been included in OM&A costs in the application; only the cost and time being spent on EEDO utility work is reflected in the application. The decrease in IT services being provided relates to the IT position being moved from EEDO to the EOOMI affiliate part way through 2022.

consistently in all applicable tables and calculations for shared services costs of this application. In the alternative, please explain and provide any necessary corrections.

EEDO Response:

The 0.61 FTE referenced on page 66 was calculated as: 35% of 75% of the Vice President, Ontario Region position and 35% of 100% of the Director Ontario Operations (35% x 75% + 35% x 100% = 61% or 0.61 FTE). The reference to 35% should have been 37% as per Table 4.4.2-6 and should have resulted in an approximate FTE amount on page 66 of 0.65 FTE (37% x 75% + 37% x 100% = 65% or 0.65 FTE). The FTE figure on page 90 should have referenced this 0.65 FTE amount.

EEDO confirms that the Management Oversight allocation amount in table 4.4.2-7 is correct and is based on the 37% allocation percentage noted in Table 4.4.2-6.

4-Staff-54
Corporate Shared Services from EPCOR Utilities
Ref: Exhibit 4 / Tab 1 / Schedule 1 / pages 74-87

Preamble:

EPCOR Electricity Distribution Ontario states that it obtains corporate shared services from its parent corporation, EPCOR Utilities. The amounts paid to EPCOR Utilities for corporate shared services reflect three categories - directly assignable costs, allocable costs and corporate asset usage fees. EPCOR Electricity Distribution Ontario provided the allocation methods applicable to the allocable corporate services costs, as well as the allocation percentages for 2022 Bridge Year and 2023 Test Year in Table 4.4.2-9, Table 4.4.2-10 and Table 4.4.2-11 in the application.

Question(s):

a) Please discuss if all services listed (by department and function) in Table 4.4.2-9 are related to and necessary for EPCOR Electricity Distribution Ontario's regulated electricity distribution business. Have there been any major changes in the service categories (including department and function information) and associated allocators since 2019?

EEDO Response:

All services in Table 4.4.2-9 are related to and necessary for EPCOR Electricity Distribution Ontario's regulated electricity distribution business. The use of the causation allocators ensures that EPCOR Electricity Distribution Ontario's share of Corporate Services costs reflects their level of provided service relative to the other Business Units within the Group.

As noted in Step 2 of the corporate cost allocation process on page 75 of the Application, where there are specific services that are not provided to all Business Units, these are identified and charged directly to the specific Business Units involved in order to ensure equity in cost allocation. Table 4.4.2-12 of the Application identifies the specific Corporate Services directly assigned to EEDO, being IS Application support and operations relating to specific applications and licenses used by EEDO. Examples of other costs not charged to EEDO include community donations organized by the Public and Government Affairs group or Health & Safety training provided to specific business units but organized through the Health, Safety and Environment group.

Since 2019 there have been three new service categories and two reorganizations within service categories to promote operational efficiencies. The two new service categories were:

- Creation of a new centralized accounts receivable team within Corporate Finance Services, which brought together existing staff from various BU's into one group. This centralization occurred in January 2021. The allocator to EEDO is based on number of AR invoices.
- Creation of a new Organizational Project Management function in order to develop a company-wide standardized approach for project management (i.e., standardized systems, processes and practices) and ensure cross-functional efficiencies. This occurred in June 2020. The allocator to EEDO is based on relative amount of PPE.
- Creation of a new consolidated Learning and Development group within Human Resources, which brought together existing staff from the BU's in order to deliver a centrally managed training and development service in April 2019. This group develops core curriculum and generic training programs (such as First Aid, Ethics training, Mental Health training) as well as oversight of the learning systems and processes to support records administration. The allocator to EEDO is based on number of Canadian headcount.
- The reorganization of the procurement team in the fall of 2020 which led to FTE's previously embedded within the Business Units being centralized within Corporate Services in order to establish a more standard and consistent approach to procurement. The allocator to EEDO is based on embedded Supply Chain Management headcount.
- An organizational change to the Security team. This team previously reported into Supply Chain Management but was moved to report within Health, Safety and the Environment (which has been subsequently renamed as Health, Safety, Security and the Environment). This restructuring occurred in April 2022, after the Application was submitted and so the security group is still reflected under the Supply Chain

Management group. However there are no impacts on forecast costs or allocators, which remain based on Canadian Headcount.

b) EPCOR Electricity Distribution Ontario notes that the allocation percentages used in developing the 2022 Bridge Year (Table 4.4.2-10) and 2023 Test Year (Table 4.4.2-11) were based on EPCOR Utilities' 2023 budget. Please explain why the 2022 and 2023 allocation percentages are both based on 2023 budget data and why they are based on the parent company's budget. Is data from each business unit (affiliate company) used in calculating the percentages?

EEDO Response:

The 2022 and 2023 allocation percentages are both based on 2023 budget data because, as part of EPCOR's annual budget process, the forecast for the current year (in this case 2022) is updated at the same time and with the same level of detail as for the next budget year (2023). As part of the budgeting process each Business Unit is required to provide data for their Business Unit to Corporate to facilitate an update to the allocators. This process ensures consistency of assumptions required to calculate the appropriate allocation of Corporate Service costs to each Business Unit.

c) Please briefly illustrate how the allocation percentages noted in part b) are derived. Have there been any major changes in the percentages assigned to EPCOR Electricity Distribution Ontario in 2022 and 2023 (compared to prior years or between 2022 and 2023)? If yes, please provide explanations.

EEDO Response:

As noted above to response b) above, part of the budgeting process each Business Unit is required to provide data for their Business Unit to Corporate to facilitate an update to the allocators.

The allocators and percentages applied to EEDO for 2022 and 2023 were shown in Table 4.4.2-10 Column C for 2022 and Table 4.4.2-11 Column C for 2023. In addition, the 2021 actual drivers and percentages are included in the table. Between 2021 and 2023 the only allocation percentages that changed significantly relate to net income as net income was positive in 2021, forecast to be a net loss in 2022 leading to no net income allocation percentage in 2022 and the forecast to be positive in 2023. The change in net income forecast also results in the change in Treasury Operations allocator between 2021 and 2023 as net income is used in that weighted average allocator.

In addition to net income the Direct IS allocators change slightly between 2021 and 2022 due to a relative increase in Direct IS operating costs relative to other Business Units.

The composite allocator has also changed slightly between 2022 and 2023 as the revenue forecast used in the composite allocator calculation has increased compared to other Business Units.

d) As shown in Table 4.4.2-13, the Public and Government Affairs (P&GA) service cost is estimated to increase from $3,736 in 2022 Bridge Year to $21,123 in 2023 Test Year. EPCOR Electricity Distribution Ontario notes that the cost driver is net income and is anticipating earning its ROE for 2023 Test Year versus having lower earnings in 2022 as a result of the long time lag from Collus PowerStream's last rebasing filing. Please explain what ROE data has been used in this estimation and how it derived the relatively significant increase in P&GA cost in question.

EEDO Response:

EEDO is anticipating earning its approved ROE in the 2023 Test Year, which results in a forecast improvement in net income between 2022 and 2023 (moving from a forecast net loss in 2022 to positive net income in 2023). This improvement in net income is reflected in the relative percentage of consolidated net income that is used to allocate the Community Relations and Corporate Communications departments within P&GA. In 2022, as EEDO is projecting a net loss, it is not allocated any Corporate Communications or Community Relations costs. The increase in allocated P&GA corporate costs is the result of the forecast improvement in 2023 net income. The overall costs of those departments has not changed significantly but the fact that EEDO is now projecting a net income in 2023 has led to the increase in allocation.

e) Table 4.4.2-13 appears to be cut off in columns A and B as some dollar amounts do not show properly. Please provide a complete version of Table 4.4.2-13.

EEDO Response:

Table 4.4.2-13

EUI Corporate Shared Services Costs Allocated to EEDO ($)

		A	B	C	D	E
	Function	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1	SCM	69,960	44,887	47,483	49,072	53,970
2	HR	92,417	101,465	110,466	116,390	127,880
3	IS	109,006	83,157	96,801	112,552	131,460

4	Corporate Finance Services	42,388	40,639	45,673	44,467	42,921
5	Executive and Executive	19,794	19,192	19,817	21,209	22,036
6	Treasury	6,647	6,452	9,861	9,338	10,448
7	Board	11,776	10,068	10,017	11,477	12,642
8	Audit and Risk Management	9,926	13,268	14,679	16,781	16,124
9	P&GA	2,536	2,609	10,574	3,736	21,123
10	Legal Services	14,427	15,530	15,743	15,771	16,805
11	HSE	8,607	16,828	14,779	15,514	12,353
12	Incentive Compensation	44,517	45,762	72,652	55,865	56,441
13	**EEDO Total**	**432,001**	**399,857**	**468,545**	**472,172**	**524,203**
14	Variance		(32,144)	68,688	3,627	52,031

4-Staff-55
Allocated Corporate Asset Usage Fees
Ref: Exhibit 4 / Tab 1 / Schedule 1 / pages 86-88

Preamble:

EPCOR Electricity Distribution Ontario states that the asset usage fee for each category of corporate assets is comprised of two components: "return on" capital and "return of" capital (or depreciation expense). The return on capital component is calculated using the service recipient's weighted average cost of capital (WACC). Table 4.4.2-14 in Exhibit 4 lists the 2019 actual to 2023 Test Year's asset usage fees allocated to EPCOR Electricity Distribution Ontario by asset category.

Question(s):

a) Please provide the allocation methodology for the asset usage fees. Please discuss the rationale of the methodology and any major changes to the method since 2019.

EEDO Response:

The allocation methodology for asset usage fees is a similar process to that used to allocate operating costs. For each asset category, an appropriate driver is selected which is considered to reflect the activity driving the asset investment. The driver information for each Business Unit is collected and the total asset usage fee (both depreciation and return on assets) is then allocated to each Business Unit based on their relative share of the underlying driver.

Leasehold asset costs are allocated using a two step allocation process. The first step allocates the Leasehold Asset costs based on the business unit's share of space occupied in EPCOR Tower compared to the total space occupied by the EPCOR group within EPCOR Tower. The second step allocates Corporate Services' share of Leasehold Asset costs based on the business unit's proportionate share of allocated Corporate Services costs. Corporate

Services' share of Leasehold Asset costs are determined based on Corporate Services' share of space occupied in the EPCOR Tower compared to the total space occupied by the EPCOR group.

HRIS asset category costs are allocated to each EPCOR subsidiary based on each business unit's employee headcount relative to the total employee headcount in all EPCOR business units. HRIS is used to recruit, hire, manage and pay EUI employees and as such employee headcount is reflective of the benefits received by each business unit.

Information Services Infrastructure asset costs are allocated to each EPCOR business unit based on the IS costs directly assigned to each business unit relative to the IS operating costs directly assigned to all EPCOR business units. This allocation method is appropriate because the amount of IS costs directly assigned to each business unit is reflective of the business unit's share of the IS Infrastructure assets used to provide the IS support. As such, the allocation driver reflects this relationship.

Financial Systems asset category costs have been allocated to each EPCOR subsidiary based on the weighted average of the cost allocators for two primary functions of the financial system:

i. the weighted average operating costs related to the Corporate Finance and Payroll functions and
ii. the weighted average number of the Purchase Order Lines by business unit. The use of Purchase Order Lines by business unit as an allocator is reflective of the activity and costs incurred to process a Purchase Order.

Furniture and fixture assets costs since 2019 are allocated to each EPCOR business unit based on the business unit's proportionate share of allocated Corporate Services costs. This was a change in allocation implemented at the start of 2019 to reduce the administrative burden in maintaining cost allocation models.

Since then, there have been no additional changes to the methodology used to allocate the furniture and fixtures costs.

b) Please explain how the return on capital component is calculated using the service recipient's WACC.

EEDO Response:

Return on assets is calculated in a similar manner to other allocated costs. The starting point is the mid year rate base of the asset category for Corporate Services. The amount attributable to each business unit is then identified using the various drivers discussed above. These drivers are also used to allocate depreciation expense. Finally the return piece is then applied to the allocated mid year asset base based on a forecast WACC rate for each business unit. The forecast WACC may be different to the final applied for/approved rate as the return on assets calculation normally occurs before finalization of forecast debt.

For 2022 and 2023 the forecast WACC rate used for EEDO was 6.03% based on timing of preparing the information. This is higher than the applied for rate in 2023 of 5.74% due to more accurate information used by the time of the application. For 2023, the return on assets would be $1,403 lower (calculated as the forecast 2023 return on assets of $29,187 adjusted for the change in WACC rates of 5.74%/6.03%). As these amounts are immaterial EEDO is not recommending any adjustment be made to the filed amounts.

c) In Table 4.4.2-14, if “Return on Assets” is a component of each corporate asset listed above line 6 in the table, why there is a separate line 6 for Return on Assets in this table? What kind of cost does this category “Return on Assets” represent?

EEDO Response:

Row 6 of Table 4.4.2-14 reflects the total return on assets for all asset categories listed above and although calculated separately for each asset category it was not been split out by separate asset category in the table. This return reflects the equity cost that has been incurred in order to invest in IT infrastructure and leasehold and furniture assets.

d) Do lines 1 to 5 in Table 4.4.2-14 represent the “return of” capital (depreciation expense) component of the corporate assets?

EEDO Response:

Confirmed. Lines 1 to 5 in Table 4.4.2-14 represent the allocation of depreciation expense for each asset category (separate from the return on assets shown in row 6).

e) For each category of assets listed in the Table 4.4.2-14, what is the depreciation rate used? How is this rate determined, and is the rate the same as or different from the depreciation rate used by EPCOR Electricity Distribution Ontario? Please explain the response.

EEDO Response:

The depreciation rates used for the asset categories are as follows:

Leasehold Assets – this includes disaster recovery and EPCOR Tower leasehold improvements. The depreciation rate assumes a useful life of 5 to 20 years, which is calculated based on the date of the improvement compared to the remaining term of each specific lease. The useful life for EEDO leased assets is 10 years as that reflects the specific leaseholds held by EEDO.

HRIS - this is the software system used by EPCOR's HR department for payroll, recruiting, hiring and employee management. The depreciation rates assumes a useful life of 5 to 10 years, calculated based on the date of each upgrade over the remaining life to the expected end of support for the current HR system. There is no equivalent separate asset category for EEDO directly owned assets.

IS Infrastructure – this category includes servers, electronic storage devices, networks, desktops, laptops and specific applications. The depreciation rate assumes a useful life of 3 years for phones, 4 years for desktops, and 5 to 20 years for servers and other software applications depending on the expected period of support for the application. The useful lives for EEDO directly owned IS assets are 3 to 5 years which is broadly consistent with Corporate. Corporate Services owns major software applications used across all Business Units as well as more server infrastructure which will have longer lives.

Financial Systems – this category relates to the financial application used across EPCOR for invoice processing, recording and reporting of financial information, preparation of financial statements, depreciation calculations and purchasing along with specific servers, storage devices and networks associated with the Oracle Financial system. The depreciation rate assumes a useful life of 5 to 20 years based on the date of each upgrade until the expected end of support for the current version of Oracle. There is no equivalent separate asset category for EEDO directly owned assets.

Furniture and Fixtures – this category includes offices, workstations, file cabinets and modular walls. The depreciation rates assume a useful life of 8 to 15 years depending on the specific asset. The useful life for EEDO directly owned assets is 10 years. The wider range for Corporate assets reflects the larger inventory of assets leading to more detailed componentization applied by Corporate Services.

Exhibit 5 – Cost of Capital and Capital Structure

5-Staff-56
Long-term Debt
Ref: Exhibit 5 / Tab 1 / Schedule 1 / pages 6 to 10
Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, issued December 11, 2009

4.4.2 Shared Services and Corporate Cost Allocation

The nature, amount and delivery of Shared Services provided by affiliates to EEDO has changed since EEDO's last approved Cost of Service filing for the 2013 year. At the time of EEDO's last rate application (OEB Approved 2013), EEDO received Shared Services from an affiliate (Collus PowerStream Solutions Corp.) related to supervisory, operational, engineering, finance, information technology and administrative services. Several of these functions (previously included in Shared Service allocations) are now embedded within EEDO. Refer to the end of this section for 2023 Test Year versus 2013 Actual variances and explanations.

As of the October 1, 2018 acquisition date by EPCOR and for subsequent periods, EEDO has received Shared Service support from several EPCOR affiliates in order to conduct the operations of the utility.

EEDO obtains Shared Services from its affiliate companies EPCOR Water Services Inc. ("EWSI"), EPCOR Distribution and Transmission Inc. (EDTI), EPCOR Ontario Operations Management Inc. ("EOOMI") and EPCOR Ontario Utilities Inc. (EOUI) (collectively "Affiliate Shared Services"), as well as its parent EUI ("Corporate Shared Services"). A detailed explanation of the types of services provided by each affiliate to EEDO is set out in the next section below.

Shared Services costs are determined on a cost recovery basis in accordance with the Affiliate Relationship Code for Electric Utilities (ARC) and the services are delivered in accordance with a Service Level Agreement ("SLA"). The allocation of Shared Services is assessed regularly and adjusted as appropriate.

For some functional categories, such as Human Resources, Supply Chain and Public and Government Affairs, services are provided from EUI and EOOMI or EWSI. In these instances, the services provided by EUI tend to be more related to governance, oversight and broad policy considerations, while the services provided by EOOMI or EWSI are more tactical and/or more direct oversight in nature and are driven by the specific business needs of EEDO.

Table 4.4.2-1 below shows the 2019 Actual through 2021 Actual, 2022 Bridge Year and 2023 Test Year's total Shared Services costs provided to EEDO.

Table 4.4.2-1

Shared Services and Corporate Cost Allocated to EEDO

($)

		A	B	C	D	E
	Expense Category	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1	Affiliate Shared Services	365,093	557,435	510,909	757,748	790,070
2	Corporate Shared Services	740,333	681,659	659,924	791,931	875,084
3	**Total Shared Services and Corporate Costs**	**1,105,426**	**1,239,094**	**1,170,833**	**1,549,679**	**1,665,154**

Affiliate Shared Services

Table 4.4.2-2 below shows the 2019 Actual through 2021 Actual, 2022 Bridge Year and 2023 Test Year's total affiliate Shared Services from EWSI, ECSI and EOUI.

Table 4.4.2-2

Affiliate Shared Services Allocated to EEDO

($)

	A	B	C	D	E
Affiliate Service Provider	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1 EWSI	103,993	39,677	15,027	15,000	15,300
2 EDTI	-	24,155	24,888	40,000	40,800
3 EOOMI/EOUI	261,100	493,603	470,994	702,748	733,970
4 **Total**	**365,093**	**557,435**	**510,909**	**757,748**	**790,070**

Shared Services Provided by EWSI

The following is a general description of the Shared Services provided by EWSI to EEDO:

a. Supply Chain Management (SCM) - services for purchasing and strategic sourcing including management of the end-to-end procurement process for the goods required by EEDO.
b. Public and Government Affairs (P&GA) – services related to internal and external communication and stakeholder and public consultation requirements of EEDO.
c. Human Resources (HR) – provides human resource consulting; support of recruitment efforts and disability management for EEDO employees.
d. Project Management Office (PMO) – provides project controls, governance and project standardization and support for EEDO.

The Shared Services costs are determined on a cost recovery basis in accordance with the ARC and and are reflected in a SLA between the parties. The allocation methodologies have been designed to ensure that the allocation of EWSI's Shared Services costs are fair and reasonable, cost-effective, predictable and reflect the benefit received by function. Costs are directly charged based on time spent supporting EEDO's operations.

Table 4.4.2-3 below shows the 2019A – 2021A, 202 Bridge Year and 2023 Test Year's total EWSI Shared Services costs.

Table 4.4.2-3
EWSI Shared Services Costs Allocated to EEDO
($)

		A	B	C	D	E
	Shared Service	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1	SCM	88,639	27,928	1,694	1,700	1,734
2	P&GA	8,299	-	4,516	4,500	4,590
3	HR	1,302	11,749	7,400	7,400	7,548
4	PMO	5,753	-	1,417	1,400	1,428
5	**Total**	**103,993**	**39,677**	**15,027**	**15,000**	**15,300**
6	Variance		(64,316)	(24,650)	(27)	300

EWSI shared costs are expected to be flat from the 2021 Actual to the 2023 Test Year. EWSI shared costs have reduced from the 2019 Actual and 2020 Actual levels primarily due to EEDO no longer requiring as much SCM services as costs incurred in 2019 Actual and 2020 Actual, which primarily related to supporting EEDO in setting up EEDO's inventory in the Oracle Inventory system and related training costs for EEDO staff to learn the system.

The overall trend in costs from the 2022 Bridge Year to the 2022 Test Year remains flat with increases primarily due to inflation.

Shared Services Provided by EDTI

The following is a general description of the Shared Services provided by EDTI to EEDO:

a. Systems control operation services – these services include monitoring EEDO's SCADA alarms for station outages/issues, and being first point of call from Util-Assist if there is an outage afterhours reported from customers and contacting the on-call technician if a situation arises. Services also include contacting Hydro-One if hold-offs from Hydro One are required.

These services were previously provided by EEDO's former 50% shareholder Alectra and in the 2019 Actual year, Alectra did not charge any amounts to provide these services (this appears to have been an error on Alectra's part as a service level agreement at an annual cost of $26,400 was in place between EEDO and Alectra). Alectra was no longer able to provide these services after 2019 and EEDO does not have the capacity to self-perform these services.

The Shared Services costs are determined on a cost recovery basis in accordance with the ARC and are reflected in a SLA between the parties. The allocation methodologies have been designed to ensure that the allocation of EDTI's Shared Services costs are fair and reasonable, cost-effective, predictable and reflect the benefit received by function. Costs are directly charged based on an estimate of spent supporting EEDO's operations.

Table 4.4.2-4 below shows the 2019A – 2021A, 202 Bridge Year and 2023 Test Year's total EDTI Shared Services costs.

Table 4.4.2-4

EDTI Shared Services Costs Allocated to EEDO

($)

	A	B	C	D	E
Shared Service	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1 System Controls	-	24,155	24,888	40,000	40,800

3	**Total**	**-**	**24,155**	**24,888**	**40,000**	**40,800**
4	Variance		24,155	733	15,112	800

The increase in costs from the 2021 Actual Year to the 2023 Test Year is the result of adding the following additional services in 2022:

a. Monitoring SmartMap in addition to monitoring SCADA; and
b. Developing switching orders for both planned and unplanned outages.

The overall trend in costs from the 2022 Bridge Year to the 2023 Test Year remains flat with increases primarily due to inflation.

Shared Services Provided by EOOMI/EOUI

Beginning in 2022, Shared Services related to EPCOR's Ontario operations are provided by EOOMI. The individuals providing this service were transferred to EEOMI from EOUI at the end of fiscal 2021, and prior to 2022, these same services were provided by EOUI. Appropriate SLAs, compliant with ARC, are and were in place relating to all historical years since EEDO was acquired by EPCOR in 2018.

The following is a general description of the Shared Services provided by EOOMI/EOUI to EEDO, along with the rationale for service being required by EEDO:

a. Management Oversight – the Vice President, Ontario Region and the Director, Operations Ontario Region (reporting to the Vice President, Ontario Region) provide direct management and oversight to the employees and operations of EEDO, with EEDO's General Manager reporting directly into the Director, Operations Ontario Region. The Vice President Ontario Region position spends a portion of their time on new business development and as a result 25% of this positions costs has been removed from the cost allocation pool and is not allocated to EEDO as part of the cost allocations noted below.

Prior to the CEO retirement in 2015, EEDO had a CEO position. Management oversight services replaces the CEO position with the Vice President, Ontario Region allocating 35% of 75% of this position's costs and the Director, Operations Ontario allocating 35% of this position's costs in 2023 Test Year. This equates to an approximate 0.61 FTE in 2023 Test Year for executive-level oversight costs which EEDO believes is reasonable.

b. Regulatory – one Analyst, Regulatory supports the development and coordination of regulatory applications, monitors and coordinates activities or initiatives from government, departments or agencies that may affect EEDO and manages the interface between these external stakeholders.

EEDO has 1 regulatory position embedded at approximately 0.7 FTE for the 2023 Test Year. This service will add approximately 0.33 FTE for the 2023 Test Year and is required to ensure EEDO meets all of its regulatory requirements annually.

c. Human Resources – one Consultant, Human Resources supports EEDO's staff and provides a full range of human resources services including human resource management and consulting, talent management and recruitment support, disability management and labour relations.

Prior to EPCOR acquiring EEDO in 2018, EEDO had a full FTE Manager for HR. HR services are now provided from EOOMI and for the 2023 Test Year will result in an approximate 0.43 FTE for HR services.

d. Health, Safety and Environment ("HSE") – one Manager, HSE Services ensures EEDO's health, safety and environment practices and procedures are well designed and in compliance with legislation and compatible with EUI's safety management standards and procedures as well as working with EEDO staff to implement those practices and procedures.

Prior to EPCOR's acquisition of EEDO, EEDO did not have any embedded HSE employees. EPCOR determined that dedicated HSE support was required for utility operations of EEDO. HSE services are provided by EOOMI and allow EEDO to access HSE support without hiring a full FTE dedicated to the utility. For the 2023 Test Year the HSE support from EOOMI is equivalent to an approximate 0.35 FTE.

e. Customer Service – one Manager, Customer Operations provides oversight and management of EEDO's customer service and billings embedded staff.

Prior to EPCOR's acquisition of EEDO, there was a split Manager Regulatory and Billing position. Due to increased customer counts and the amount of regulatory support required for EEDO it was determined that a single position could not fulfill both responsibilities. In order to save costs versus hiring a dedicated full FTE Customer Service Manager in EEDO, customer service oversight services are now provided by EOOMI at an approximate 0.55 FTE for the 2023 Test Year.

f. OT and SCADA Support – one Computer System & Network Technician positon will provide OT and SCADA support to EEDO.

See variance explanations to Table 4.4.2-7 for additional information related to this service.

g. Operational Support – one Manager, Operations Engineering provides operations engineering support to EEDO's capital and operational engineering activities.

Operational support for EEDO's operating and capital programs has increased since 2013. Annual capital has increased from approximately $1.8 million in 2013 to over $4.2 million in 2023 Test Year while customer counts have increased from just over 16,000 in 2013 to almost 19,000 in 2023 Test Year. Increases in capital and customers have resulted in increased engineering and operational support to manage capital and operating programs. In order to save costs versus hiring a dedicated, full FTE engineering and operational support position, these services are now being provided by EOOMI at an approximate 0.35 FTE for the 2023 Test Year.

h. Ontario Facilities – office space and leasehold costs for EOOMI's employees that support EEDO.

EOOMI/EOUI provide services to the following businesses/operations in Ontario, and each of these businesses/operations are allocated a portion of EOOMI/EOUI costs based on the cost allocators for each business/operation:

a. EPCOR Electricity Distribution Ontario
b. EPCOR Natural Gas Limited Partnership – Aylmer, a regulated natural gas utility
c. EPCOR Natural Gas Limited Partnership – South Bruce, a regulated natural gas utility
d. EPCOR GL Industrial Water Inc. (Darlington) – a wastewater treatment facility operation
e. EOOMI – EOOMI is included in the cost allocation methodology and all costs allocated to EOOMI remain in EOOMI.

As further businesses/operations are added in Ontario in upcoming years these new businesses/operations will be added to the EOOMI cost allocation model and will receive a proportionate share of EOOMI costs related to providing services to these new businesses/operations.

Table 4.4.2-5 below provides information on the cost allocators used to allocate Affiliate Shared Services costs from EEOMI to EEDO. The EEOMI costs are shared amongst all Ontario regulated operations and non-regulated activities as these costs support all of these businesses/operations.

Table 4.4.2-5

Allocation of EOOMI Costs – Cost Allocators

	Responsibility Centre and Function	A Allocator
1	Management Oversight	ON Composite - Revenue, Assets, Headcount
2	Regulatory	Functional Cost Causation – Regulatory Filings
3	Human Resources	Functional Cost Causation – Headcount
4	HSE	Functional Cost Causation – Headcount
5	Customer Service	Functional Cost Causation – Customer Count
6	OT and SCADA Support	ON Composite - Revenue, Assets, Headcount
7	Operational Support	ON Composite - Revenue, Assets, Headcount
8	Ontario Facilities	Functional Cost Causation – Head Office Salaries
9	Head Office Corporate Allocations (HOCA)	Functional Cost Causation – Head Office Salaries

For the Regulatory, the number of Regulatory Filings Function Cost Causation allocator is appropriate as the number of Regulatory Filings in a given fiscal year will drive the work effort in that year. It is anticipated that for most fiscal years there will be a similar amount Regulatory Filings between the regulated utilities which EOOMI provides services to.

For both the Human Resources and HSE, the Headcount Functional Cost Causation allocator is appropriate as the services provided by these areas are highly related to the level of Headcount which the services are being provided in respect of.

For Customer Service, the Customer Count Functional Cost Causation allocator is appropriate as the services provided by this area is highly related to the amount of Customers which the services are being provided in respect of.

For Management Oversight, OT and SCADA Support and Operational Support, there is not a single Functional Cost Causation allocator which would appropriately allocate the services of these areas. The Composite cost allocator, which is a measure of the relative total size of a service recipient based on three pools – Revenues, Assets and Headcount, which are equally weighted, is appropriate where the services are more oversight and governance in nature or where the services are more dependent on the relative size of the business/operation that the service are being provided to.

Table 4.4.2-6 below shows the 2019A-2021A, 2022 Bridge Year and 2023 Test Year's % allocation to EEDO of each of EOOMI/EOUI's Affiliate Shared Service total costs for the year.

Table 4.4.2-6
EOOMI/EOUI Shared Services Costs Allocated to EEDO
($)

		A	B	C	D	E
	Shared Service	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1	Management Oversight	25%	25%	20%	38%	37%
2	Regulatory	10%	10%	N/A	33%	33%
3	Human Resources	55%	70%	55%	48%	48%
4	HSE	33%	33%	33%	38%	37%
5	Customer Service	N/A	18%	25%	59%	56%
6	OT and SCADA Support	N/A	N/A	N/A	38%	37%
7	Operational Support	N/A	40%	40%	38%	37%
8	Ontario Facilities	23%	26%	22%	29%	26%
9	HOCA	23%	26%	22%	29%	26%

For the services provided for 1 through 7 in the table above, the costs being allocated from EOOMI to EEDO are based on the related staff costs for the people performing the tasks. As a result, the percentages in the table above will translate approximately into FTEs based on the number of positions providing the relevant services multiplied by the percentages shown in the table.

Due to various changes in the businesses/operations which EOUI/EOOMI were servicing, the 2021A and prior years allocations to EPCOR's various Ontario businesses/operations were based on estimates of time spent by each Affiliate Shared Service area. For 2022 Bridge Year and all proceeding years, EOOMI costs will be allocated based on the Cost Allocators noted in Table 4.4.2-5 above.

Table 4.4.2-7 below shows the 2019A – 2021A, 2022 Bridge Year and 2023 Test Year's total EOOMI/EOUI Affiliate Shared Services costs allocated to EEDO.

Table 4.4.2-7

EOOMI/EOUI Shared Services Costs Allocated to EEDO ($)

		A	B	C	D	E
	Shared Service	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1	Management Oversight	122,727	157,590	143,121	225,331	223,165
2	Regulatory	11,475	12,533	-	29,179	39,715
3	Human Resources	-	111,042	83,007	56,978	58,851
4	HSE	54,000	58,038	54,459	67,840	67,218
5	Customer Service	-	5,811	30,780	77,990	75,984
6	OT and SCADA Support	-	-	-	34,923	58,663
7	Operational Support	-	57,709	58,186	67,632	67,012
8	Ontario Facilities	62,098	75,975	70,757	108,923	107,142
9	HOCA	10,800	14,905	30,684	33,952	36,220
10	**Total**	**261,100**	**493,603**	**470,994**	**702,748**	**733,970**
11	Variance		232,503	(22,609)	231,754	31,222

The increases in EOUI shared costs from the 2021 Actual to the 2023 Test Year are primarily due to the following items:

a. Implementing the ON Composite – Revenue, Assets, Headcounts allocator for Management Oversight and including 100% of the Director Operations, Operations Ontario Region. EOOMI has reviewed the accountabilities and time spent by this position and has determined that this position fully supports the various Ontario Operations. In the 2021 Actual, a portion of this position costs were not allocated to the various Ontario operations (40%). The position also previously allocated costs evenly to EPCOR's three regulated Ontario operations (thus EEDO was receiving 20%) however the ON Composite allocator results in a higher allocation to EEDO (35%). The impact of these changes is $50,948.

b. Implementing the ON Composite – Revenue, Assets, Headcounts allocator for Management Oversight for the Vice President, Ontario Region. EOOMI has reviewed the accountabilities and time spent by this position and has determined that 75% of this position supports the various Ontario Operations. In the 2021 Actual a portion of this position costs were not allocated to the various Ontario operations (40%). The position also previously allocated costs evenly to EPCOR's three regulated Ontario operations (thus EEDO was receiving 20%) however the ON Composite allocator results in a higher allocation to EEDO (35%). The impact of these changes is $25,159.

c. Adding an Analyst, Regulatory position to assist the existing Senior Manager, Regulatory (this position is embedded EEDO) with required regulatory applications and requirements for EPCOR's Ontario operations ($42,123). EPCOR attempted to operate with a single regulatory position in Ontario however the level of work required for meeting all regulatory requirements has necessitated an additional regulatory FTE.

d. HSE has increased from 2021 Actual primarily due to wage inflation.

e. Customer Service has increased $45,204 from 2021 Actual. For the 2021 Actual, the Customer Service Manager had spent additional time in setting up billing and customer service activities for one of EPCOR's new regulated utilities and spent a higher than normal amount of time on that implementation. For 2022 Bridge Year and 2023 Test Year, Customer Service costs are allocated based on the ON Customer Count allocator as number of customers being serviced is an appropriate cost causation allocator.

f. OT and SCADA Support being added half way through 2022 Bridge Year. In prior years, the Computer System & Network Technician position was embedded in EEDO at approximately a 0.6 FTE and this position also provided IT support services. This position has been moved to EOOMI and will allocate approximately 39% (or 0.39 FTE) costs to EEDO related to OT and SCADA support. As a result of no longer receiving IT support related to this position, EUI will be providing additional Direct IT Applications support to EEDO beginning in 2022 Test Year – see table 4.4.2-12 below for more information on the change in Direct IT Applications costs in 2023 Test Year.

g. Ontario Facilities costs increased from 2021 Actual to 2023 Test Year due to cost inflation and the Head Office Salaries cost allocator being slightly higher for EEDO for the 2023 Test Year.

These costs are partially offset by:

- 2021 Actual includes $28,268 related to the former Human Resources Manager that retired in 2021, with no similar amount in 2023 Test Year. There was an overlap period with the new Consultant, Human Resources in order to provide transition for the accountabilities to the new person.

The overall trend in costs from the 2022 Bridge Year to the 2023 Test Year shows an increase primarily due to a full year of OT and SCADA Support services in 2023 Test Year (versus a half year in 2022 Bridge Year) and inflation.

Corporate Shared Services from EUI

EEDO obtains Corporate Shared Services from its parent corporation, EUI. The amounts paid by EEDO to EUI in respect of these services (referred to collectively as Corporate Services Costs) include direct and allocated Corporate Costs and Corporate Asset Usage Fees, the latter being costs associated with the general plant assets used by EUI in providing Corporate Shared Services to EEDO. The direct and allocated Corporate Costs and Corporate Asset Usage Fees are determined on a cost recovery basis in accordance with the ARC. The direct and allocated Corporate Costs and Corporate Asset Usage Fees are reflected in a SLA between EEDO and EUI.

Table 4.4.2-8 below shows the 2019A – 2021A, 2022 Bridge Year and 2023 Test Year's Corporate Services costs charged to EEDO.

Table 4.4.2-8
Corporate Services Costs Charged to EEDO
($)

		A	B	C	D	E
	Expense Category	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1	Corporate Costs Directly Assigned	129,972	134,456	134,104	152,226	178,166
2	Corporate Costs Allocated	432,001	399,857	468,544	472,172	524,202
3	Corporate Asset Usage Fees	178,360	147,346	57,276	167,533	172,716
4	**Total EEDO Costs**	**740,333**	**681,659**	**659,924**	**791,931**	**875,084**

Consistent with its approach in previous years, EUI has allocated Corporate Services costs to the EPCOR business units using the following five step process:

a. Categorize Corporate Services costs as directly assignable or allocable.

b. Assign directly assignable costs to the appropriate business unit.

c. Review/develop/modify allocation method for allocable costs.

d. Apply allocation method to allocable costs.

e. Conduct a final review for reasonableness.

Step 1 – Categorize Corporate Services costs as either directly assignable or allocable

The first step was to review each Corporate Services cost and categorize it into one of two defined groups:

- Directly assignable costs.
- Allocable costs.

Directly assignable costs are costs that are directly associated with a particular business unit's activity or operation. The relevant Corporate Services department and business unit work together to determine the quantum of directly assigned costs, if any, related to the Corporate Service in question.

Allocable costs are those costs that provide benefits to EUI business units but by their nature cannot be directly assigned, and are charged to business units using appropriate cost allocators. These costs are allocated among EPCOR business units using cost allocators that reflect the factor or factors that drive the cost of providing the Corporate Service to each business unit.

Step 2 – Assign directly assignable costs to business units

Once the directly assignable costs are identified and determined they are charged directly to each business unit. Directly assignable costs are included in the budgets of the business units and are not included in the budgets of the respective Corporate Services departments (i.e., they are removed from the Corporate Services departments' "cost pools", with the remaining costs forming the pool of allocable costs for each department).

Step 3 – Review/develop/modify allocation method for allocable costs

EUI's cost allocation process is designed to ensure that the allocation of Corporate Services costs among business units is appropriate, fair and reasonable, cost-effective, predictable, reflects the benefit received by function or cost causation and provides for consistency with the transfer pricing principles in the ARC, and EUI's Inter-Affiliate Code of Conduct.

EUI's approach to determining its allocation methods is as follows:

The costs associated with a Corporate Services department, except for the Treasury department, are allocated on one of two bases: (i) using a single "functional cost causation allocator", or (ii) using a "composite cost causation allocator". The allocation methods used for Treasury costs are different as reflected in rows 19-20 of Table 4.4.2-9, below. For Corporate Asset Usage fees, the allocation method is further described starting in rows 30 of Table 4.4.2-9, below.

A functional cost causation allocator has been used where the costs can be logically allocated using an identified cost causation driver, such as headcount. The composite cost allocator has been used where the costs cannot be allocated using a particular functional cost causation allocator. The latter types of costs tend to be related to Corporate Services that are of a governance nature, and it is appropriate that these types of costs be allocated based on a composite cost allocator which factors in the business unit's share of EUI's total revenues, assets, and headcount.

The allocation methods applicable to EUI's allocable Corporate Services costs are summarized in Table 4.4.2-9 below.

Table 4.4.2-9

EUI's Allocators to EEDO

	Department and Function	A Allocators
	Supply Chain Management	
1	Mailroom	Functional Cost Causation - Headcount
2	Disaster Recovery Planning	Functional Cost Causation - Direct IS Costs
3	Procurement	Functional Cost Causation - SCM Embedded Headcount
4	Real Estate	Composite - EUI Revenue, Assets, Headcount
5	Security	Functional Cost Causation - Headcount
6	SCM Corporate	Composite - EUI Revenue, Assets, Headcount
	Human Resources	
7	Total Rewards	Functional Cost Causation - Headcount
8	Human Resources Consulting	Functional Cost Causation - Headcount
9	Talent Development	Functional Cost Causation - Headcount
10	Learning and Development	Functional Cost Causation - Headcount
	Information Services	
11	Major Capital Projects	Functional Cost Causation - Headcount
12	Application Services	Functional Cost Causation - Headcount
13	Infrastructure Operations	Functional Cost Causation - Direct IS Costs
	Corporate Finance Services	
14	Corporate Finance	Composite - EUI Revenue, Assets, Headcount
15	Accounts Payable	Functional Cost Causation - Number of Invoices
16	Accounts Receivable	Functional Cost Causation - Number of AR Invoices
17	Management Development Program	Composite - EUI Revenue, Assets, Headcount
	Executive and Executive Assistants	
18	Executive and Executive Assistants	Composite - EUI Revenue, Assets, Headcount
	Treasury	
19	Treasurer - Corporate Finance	40% PP&E, 30% CapEx, 30% Acquisitions
20	Treasury Operations	50% of (NI + Depreciation), 50% Debt
21	Taxation	Composite - EUI Revenue, Assets, Headcount
	EUI Board	
22	All Costs	Composite - EUI Revenue, Assets, Headcount
	Audit and Risk Management	
23	Internal Audit	Composite - EUI Revenue, Assets, Headcount
24	Organizational Project Management	Functional Cost Causation - PP&E
25	Centre of Excellence	Composite - EUI Revenue, Assets, Headcount
26	Risk Management	Functional Cost Causation - PP&E
	Public and Government Affairs	
27	VP Public & Government Affairs	Functional Cost Causation - Weighted Average of Costs for P&GA
28	Corporate Communications	Functional Cost Causation - Net Income
29	Government Relations	Functional Cost Causation - EUI Revenue, Assets, Headcount
30	Community Relations	Functional Cost Causation - Net Income
	Legal Services	
31	Legal Services	Composite - EUI Revenue, Assets, Headcount
	Health, Safety and Environment	
28	All Functions	Functional Cost Causation - Headcount
	Incentive Compensation	
29	All Costs	Average Corporate Cost Allocation
	Asset Usage Fees	
30	Leasehold Asset Costs - Disaster Recovery Leaseholds and EPCOR Tower (Leasehold Improvements)	Occupancy of EPCOR Tower and Business Unit's Proportionate Share of Corporate Services
31	Human Resources Information Services	Headcount
32	Information System Infrastructure	Business Unit's Weighted Average of Information Systems operating costs
33	Financial Systems	Business Unit's Weighted Average of i) the operating costs related to finance and payroll functions, and ii) the number of purchase order lines
34	Furniture and Fixture Assets	Business Unit's Proportionate Share of Corporate Services

The allocation percentages used in developing the 2022 Bridge Year and 2023 Test Year were based on EUI's 2023 Budget. Tables 4.4.2-10 and 4.4.2-11 below summarize the allocation percentages reflected in the in the 2022 Bridge Year and 2023 Test Year.

Table 4.4.2-10

Corporate Shared Services Allocation Percentages 2022

		A EDTI	B EEA	C EEDO	D Other	E CDN Total	F US Utilities	G Total
	Functional Cost Causation Allocators							
1	Headcount	712	328	32	1,845	2,917	442	3,359
2	CAD Headcount percentage	24.4%	11.2%	1.1%	63.3%	100.0%	0.0%	100.0%
3	Headcount percentage	21.2%	9.8%	1.0%	54.9%	86.8%	13.2%	100.0%
4	Assets	2,821.02	205.72	69.98	8,651.87	11,748.59	1,932.60	13,681.19
5	Assets percentage	20.6%	1.5%	0.5%	63.2%	85.9%	14.1%	100.0%
6	PP&E	2,703.90	0.88	38.83	8,126.54	10,870.15	1,608.95	12,479.10
7	PP&E percentage	21.7%	0.0%	0.3%	65.1%	87.1%	12.9%	100.0%
8	CapEx	203.00	1.33	3.46	490.12	697.91	106.59	804.50
9	CapEx percentage	25.2%	0.2%	0.4%	60.9%	86.8%	13.2%	100.0%
10	Debt	1,554.02	44.47	20.28	2,604.19	4,222.95	755.73	4,978.69
11	Debt percentage	31.2%	0.9%	0.4%	52.3%	84.8%	15.2%	100.0%
12	Revenues	729.78	422.43	9.31	714.18	1,875.70	313.63	2,189.33
13	Revenues percentage	33.3%	19.3%	0.4%	32.6%	85.7%	14.3%	100.0%
14	Depreciation	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1
15	Depreciation Percentage	28.4%	2.1%	0.5%	51.8%	82.9%	17.1%	100.0%
16	Net Income	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1
17	Net Income Percentage	26.0%	13.5%	0.0%	46.3%	85.8%	14.2%	100.0%
18	Direct IS	2.75	1.62	0.10	4.79	9.26	0.97	10.23
19	CAD Direct IS percentage	29.7%	17.5%	1.1%	51.7%	100.0%	0.0%	100.0%
20	Direct IS percentage	26.9%	15.9%	1.0%	46.8%	90.5%	9.5%	100.0%
21	Invoice Lines	95,300	7,478	13,981	329,469	446,228	0.00	446,228
22	Invoice Lines percentage	21.4%	1.7%	3.1%	73.8%	85.0%	0.0%	100.0%
23	AR Invoices	4,611	264	0	2,989	7,864	0.00	7,864
24	AR Invoices Percentage	58.6%	3.4%	0.0%	38.0%	100.0%	0.0%	100.0%
25	SCM Embedded Headcount	34	0	0	39	73	5	78
26	SCM Embedded Headcount percentage	43.2%	0.0%	0.0%	50.4%	93.6%	6.4%	100.0%
27	PO Lines	11,417	268	1,103	24,211	36,999	0	36,999
28	PO Lines percentage	30.9%	0.7%	3.0%	65.4%	100.0%	0.0%	100.0%
29	Acquisitions	2	1	0	3	6	4	10
30	Acquisitions percentage	20.0%	10.0%	0.0%	30.0%	60.0%	40.0%	100.0%
	Treasury Allocators							
31	**Treasurer - Corporate Finance Allocator**							
32	PP&E %	21.7%	0.0%	0.3%	65.1%	87.1%	12.9%	100.0%
33	Calculation Weighting %	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
34	**Weighting - PPE**	**8.7%**	**0.0%**	**0.1%**	**26.0%**	**34.8%**	**5.2%**	**40.0%**
35	CapEx %	25.2%	0.2%	0.4%	60.9%	86.8%	13.2%	100.0%
36	Calculation Weighting %	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
37	**Weighting - Cap Ex**	**7.6%**	**0.0%**	**0.1%**	**18.3%**	**26.0%**	**4.0%**	**30.0%**
38	Acquisitions %	20.0%	10.0%	0.0%	30.0%	60.0%	40.0%	100.0%
39	Calculation Weighting %	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
40	**Weighting - Acquisitions**	**6.0%**	**3.0%**	**0.0%**	**9.0%**	**18.0%**	**12.0%**	**30.0%**
41	**Total - All Weightings - Treasurer Corporate Finance Allocation**	**22.2%**	**3.1%**	**0.3%**	**53.3%**	**78.9%**	**21.1%**	**100.0%**
42	**Treasury Operations - Allocator**							
43	Weighting - Net Income + Depreciation	27.2%	7.8%	0.3%	49.0%	84.3%	15.7%	100.0%
44	Calculation Weighting %	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
45	**Weighting - Net Inc + Depn**	**13.6%**	**3.9%**	**0.1%**	**24.5%**	**42.2%**	**7.8%**	**50.0%**
46	Debt %	31.2%	0.9%	0.4%	52.3%	84.8%	15.2%	100.0%
47	Calculation Weighting %	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
48	**Weighting - Debt**	**15.6%**	**0.4%**	**0.2%**	**26.2%**	**42.4%**	**7.6%**	**50.0%**
49	**Total - NI & Depn + Debt - Treasury Operations Allocation**	**29.2%**	**4.4%**	**0.3%**	**50.7%**	**84.6%**	**15.4%**	**100.0%**
	Composite Cost Causation Allocator							
50	Revenues	33.3%	19.3%	0.4%	32.6%	85.7%	14.3%	100.0%
51	Assets	20.6%	1.5%	0.5%	63.2%	85.9%	14.1%	100.0%
52	Headcount	21.2%	9.8%	1.0%	54.9%	86.8%	13.2%	100.0%
53	**Average - Composite Cost Causation**	**25.0%**	**10.2%**	**0.6%**	**50.3%**	**86.1%**	**13.9%**	**100.0%**

Note 1: Forecast net income will not be provided as EPCOR's policy, as established by its Board of Directors, does not permit the disclosure of forward looking net income information.

Table 4.4.2-11
Corporate Shared Services Allocation Percentages
2023

		A EDTI	B EEA	C EEDO	D Other	E CDN Total	F US Utilities	G Total
	Functional Cost Causation Allocators							
1	Headcount	721	319	32	1,737	2,809	444	3,252
2	CAD Headcount percentage	25.7%	11.3%	1.1%	61.8%	100.0%	0.0%	100.0%
3	Headcount percentage	22.2%	9.8%	1.0%	53.4%	86.3%	13.7%	100.0%
4	Assets	2,964.73	192.71	72.23	9,112.66	12,342.33	2,067.89	14,410.23
5	Assets percentage	20.6%	1.3%	0.5%	63.2%	85.6%	14.4%	100.0%
6	PP&E	2,847.69	0.84	41.07	8,590.69	11,480.29	1,735.66	13,215.95
7	PP&E percentage	21.5%	0.0%	0.3%	65.0%	86.9%	13.1%	100.0%
8	CapEx	222.00	0.70	3.42	428.74	654.86	109.22	764.08
9	CapEx percentage	29.1%	0.1%	0.4%	56.1%	85.7%	14.3%	100.0%
10	Debt	1,614.86	40.59	21.81	2,847.76	4,525.01	807.55	5,332.56
11	Debt percentage	30.3%	0.8%	0.4%	53.4%	84.9%	15.1%	100.0%
12	Revenues	786.60	419.34	10.74	744.16	1,960.83	328.24	2,289.07
13	Revenues percentage	34.4%	18.3%	0.5%	32.5%	85.7%	14.3%	100.0%
14	Depreciation	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1
15	Depreciation Percentage	28.5%	2.0%	0.6%	51.6%	82.8%	17.2%	100.0%
16	Net Income	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1
17	Net Income Percentage	27.9%	9.7%	0.3%	48.2%	86.0%	14.0%	100.0%
18	Direct IS	2.96	1.83	0.11	4.89	9.79	0.97	10.76
19	CAD Direct IS percentage	30.2%	18.7%	1.1%	49.9%	100.0%	0.0%	100.0%
20	Direct IS percentage	27.5%	17.0%	1.0%	45.5%	91.0%	9.0%	100.0%
21	Invoice Lines	95,300	7,478	13,981	329,469	446,228	0.00	446,228
22	Invoice Lines percentage	21.4%	1.7%	3.1%	73.8%	100.0%	0.0%	100.0%
23	AR Invoices	4,611	264	0	2,989	7,864	0.00	7,864
24	AR Invoices Percentage	58.6%	3.4%	0.0%	38.0%	100.0%	0.0%	100.0%
25	SCM Embedded Headcount	34	0	0	33	66	5	71
26	SCM Embedded Headcount percentage	47.2%	0.0%	0.0%	45.8%	93.0%	7.0%	100.0%
27	PO Lines	11,417	268	1,103	24,211	36,999	0	36,999
28	PO Lines percentage	30.9%	0.7%	3.0%	65.4%	100.0%	0.0%	100.0%
29	Acquisitions	2	1	0	3	6	4	10
30	Acquisitions percentage	20.0%	10.0%	0.0%	30.0%	60.0%	40.0%	100.0%
	Treasury Allocators							
31	**Treasurer - Corporate Finance Allocator**							
32	PP&E %	21.5%	0.0%	0.3%	65.0%	86.9%	13.1%	100.0%
33	Calculation Weighting %	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
34	**Weighting - PPE**	**8.6%**	**0.0%**	**0.1%**	**26.0%**	**34.7%**	**5.3%**	**40.0%**
35	CapEx %	29.1%	0.1%	0.4%	56.1%	85.7%	14.3%	100.0%
36	Calculation Weighting %	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
37	**Weighting - Cap Ex**	**8.7%**	**0.0%**	**0.1%**	**16.8%**	**25.7%**	**4.3%**	**30.0%**
38	Acquisitions %	20.0%	10.0%	0.0%	30.0%	60.0%	40.0%	100.0%
39	Calculation Weighting %	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
40	**Weighting - Acquisitions**	**6.0%**	**3.0%**	**0.0%**	**9.0%**	**18.0%**	**12.0%**	**30.0%**
41	**Total - All Weightings - Treasurer Corporate Finance Allocation**	**23.3%**	**3.0%**	**0.3%**	**51.8%**	**78.5%**	**21.5%**	**100.0%**
42	**Treasury Operations - Allocator**							
43	Weighting - Net Income + Depreciation	28.2%	5.8%	0.4%	49.9%	84.4%	15.6%	100.0%
44	Calculation Weighting %	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
45	**Weighting - Net Inc + Depn**	**14.1%**	**2.9%**	**0.2%**	**25.0%**	**42.2%**	**7.8%**	**50.0%**
46	Debt %	30.3%	0.8%	0.4%	53.4%	84.9%	15.1%	100.0%
47	Calculation Weighting %	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
48	**Weighting - Debt**	**15.1%**	**0.4%**	**0.2%**	**26.7%**	**42.4%**	**7.6%**	**50.0%**
49	**Total - NI & Depn + Debt - Treasury Operations Allocation**	**29.2%**	**3.3%**	**0.4%**	**51.7%**	**84.6%**	**15.4%**	**100.0%**
	Composite Cost Causation Allocator							
50	Revenues	34.4%	18.3%	0.5%	32.5%	85.7%	14.3%	100.0%
51	Assets	20.6%	1.3%	0.5%	63.2%	85.6%	14.4%	100.0%

52	Headcount	22.2%	9.8%	1.0%	53.4%	86.3%	13.7%	100.0%
53	**Average - Composite Cost Causation**	**25.7%**	**9.8%**	**0.7%**	**49.7%**	**85.9%**	**14.1%**	**100.0%**

Note 1: Forecast net income will not be provided as EPCOR's policy, as established by its Board of Directors, does not permit the disclosure of forward looking net income information

Step 4 – Apply allocation methods to allocable costs

Once the allocation methods were determined, they were applied against EUI's final budgeted Corporate Services costs to arrive at the amounts charged to each business unit.

Step 5 - Final review of Corporate Services costs for reasonableness

The resulting Corporate Services costs were carefully reviewed by management to confirm that the process set out above was properly applied, and that the resulting charges were reasonable.

Directly Assigned Corporate Services Costs

The following is a general description of the Corporate Shared Services costs that are directly assigned to EEDO:

- Information Services ("IS") Application Support – in this cost category are large business unit specific applications. The support costs for each application are recorded in general ledger accounts specific to the application.
- IS Infrastructure Operations – this cost category is made up of charges for the servers, storage, user devices, network and employee services (i.e., service desk services, licensing).

Table 4.4.2-12 shows the Corporate Services costs for 2019 Actual – 2021 Actual, 2022 Bridge Year and 2023 Test Year that are directly assigned to EEDO for IS Application Support and IS Infrastructure Support (i.e., desktops, servers, network, databases, printers, etc.).

Table 4.4.2-12

Directly Assigned Corporate Services Costs to EEDO

($)

		A	B	C	D	E
	Expense Category	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1	IS Application Support	44,330	50,29	56,141	64,171	83,542
2	IS desktops, printers and network	85,642	84,16	77,963	88,055	94,624
4	**Total EEDO Costs**	**129,972**	**134,456**	**134,104**	**152,226**	**178,166**
5	Variance		4,484	(352)	18,122	25,940

The increase in costs from the 2021 Actual Year to the 2023 Test Year is the result of the following:

a. IT Application Support cost increases in due to additional IT support being required as a result of the Computer System & Network Technician being moved to EOOMI and this position no longer providing IT support to EEDO (approximately $18,000). See variance explanations to Table 4.4.2-7 for additional information.

b. The remaining variance is due to general cost inflation.

The increase in costs from 2022 Bridge Year to 2023 Test Year is primarily due to the additional IT support being required as a result of the Computer System & Network Technician being moved to EOOMI and this position no longer only providing IT support to EEDO and general cost inflation.

Allocated Corporate Shared Services Costs

The following is a general description of the Corporate Services costs that are allocated to EEDO:

a. Supply Chain Management (SCM) includes mailroom, disaster recovery planning facilities, procurement, real estate, security and space rent of EPCOR Tower located in Edmonton which houses the majority of the Corporate Services employees.

b. Human Resources (HR) includes the administration and management of employee compensation and benefits programs; administration and management of payroll functions; human resource consulting; support of recruitment efforts, job and organizational design, and succession and workforce planning; labour and employee relations; administration and management of Human Resource and Information System (HRIS); the delivery of professional development courses and technical training across all EPCOR business units and Corporate Services departments.

c. Information Services (IS) manages the implementation of major applications and the installation of major computer hardware devices, user support services related to shared business system applications and the operation and maintenance of the computer hardware platforms (i.e., servers, networks, etc.) and operating systems that shared applications (i.e., Oracle business system) and business unit specific systems applications.

d. Corporate Finance Services includes Corporate Finance (corporate accounting, consolidated reporting and analysis and audit fees), accounts payable, accounts receivable, management development of junior level finance employees.

e. Executive and Executive Assistants provide governance and leadership services to EUI subsidiaries.

f. Treasury performs the services associated with raising capital and provides banking and cash management services to EPCOR subsidiaries. This group also provides taxation services to all business unit operations and EUI.

g. Board Costs includes EUI's Board of Directors that provide corporate governance functions to EPCOR and its subsidiaries.

h. Audit and Risk Management provides audit and ensures compliance the Canadian legislation equivalent to the United States' Sarbanes-Oxley Act (commonly referred to as "CSOx") and provides insurance and Enterprise Risk Management services to EPCOR subsidiaries. This group also includes the Finance centre of excellence (i.e., best practices, support and training for the Oracle Financial suite of products.)

i. Public and Government Affairs (P&GA) provides internal/external communication services, liaison services and briefing support in relation to all three levels of government (federal, provincial, and municipal), as well as government agencies and staff, with respect to existing or proposed policies and legislation and community relations (i.e., community engagement tools, processes and investment strategies to support EPCOR's reputation and relationship objectives. EEDO notes that a portion of Community Relations costs includes community donations ($1,904) and these costs have been removed and not included in the revenue requirement.

j. Legal Services provides legal, governance, and compliance related activities to EEDO and other EUI business units and subsidiaries.

k. Health, Safety and Environment (HSE) provides governance, maintenance, and ongoing implementation of HSE requirements, HSE reporting and plans and related program administration (i.e., Alcohol and Drug Program).

l. Incentive Compensation is paid to Corporate Services employees based on individual performance ratings and EUI's overall annual corporate targets. EUI's structure for compensating its non-union employees has four components: base compensation (annual salary), employer paid benefits, Short Term Incentive (STI), and Medium Term Incentive (MTI) for participating directors, vice presidents and executives. EUI's structure for compensating unionized employees has three components: base compensation (hourly wages / annual salaries), employer paid benefits and STI. The compensation was designed to bring employee total compensation to a level which is at par with comparable positions in the market from which EUI must draw employees (i.e., to market value). The program itself is not a separate service, but the costs of any incentives are tracked separately.

EEDO's Allocated Corporate Shared Services costs for 2019 Actual – 2021 Actual 2022 Bridge Year and 2023 Test Year are shown in Table 4.4.2-13 below.

Table 4.4.2-13

EUI Corporate Shared Services Costs Allocated to EEDO ($)

	Function	A **2019A**	B **2020A**	C **2021A**	D **2022 Bridge Year**	E **2023 Test Year**
1	SCM	69,960	44,887	47,483	49,072	53,970
2	HR	92,417	101,46	110,466	116,390	127,880
3	IS	109,00	83,157	96,801	112,552	131,460
4	Corporate Finance Services	42,388	40,639	45,673	44,467	42,921
5	Executive and Executive	19,794	19,192	19,817	21,209	22,036
6	Treasury	6,647	6,452	9,861	9,338	10,448
7	Board	11,776	10,068	10,017	11,477	12,642
8	Audit and Risk Management	9,926	13,268	14,679	16,781	16,124
9	P&GA	2,536	2,609	10,574	3,736	21,123
10	Legal Services	14,427	15,530	15,743	15,771	16,805
11	HSE	8,607	16,828	14,779	15,514	12,353
12	Incentive Compensation	44,517	45,762	72,652	55,865	56,441
13	**EEDO Total**	**432,00**	**399,85**	**468,545**	**472,172**	**524,203**
14	Variance		(32,144	68,688	3,627	52,031

EUI Board costs are shown in row 7 of Table 4.4.2-13. For the 2023 Test year the amount of EUI Board costs included in the EUI Corporate Shared Service Costs allocated to EEDO is $12,642.

The increase in EUI Corporate Shared Services cost from 2021 Actual to 2023 Test Year are primarily due to the following items:

a. The increase in HR costs is primarily due to increases in training-related costs back to pre-COVID levels (approximately $8k), additional net staff costs for moving disability management services in house for 2023 Test Year ($5k), increases in costs related to Diversity, Equity and Inclusion initiatives ($2k) and general cost inflation.

b. The increase in IT costs is primarily due to various IT operating projects (EPCOR.com and JIRA replacement) in 2023 Test Year ($15k), increases in staff costs in 2022 Bridge Year related to filing various vacancies ($10k) and general cost inflation.

c. The increase in P&GA costs is primarily due to increases in the allocation percentage for EEDO. The cost driver for EEDO is net income and EEDO is anticipating earning it's ROE for 2023 Test Year versus having lower earnings in 2021 Actual as a result of there being a long time lag from EEDO's last cost of service filing in 2013.

These costs are partially offset by:

d. Lower Incentive Compensation for 2021 Actual as EPCOR's results for the 2021 Actual period were above Target. The 2023 Test Year includes Incentive Compensation amounts at Target.

The increase in EUI Corporate Shared Services cost from 2022 Bridge Year to 2023 Test Year is primarily due to the following items:

a. The increase in HR costs is primarily due to additional net staff costs for moving disability management services in house for 2023 Test Year ($5k), increases in costs related to Diversity, Equity and Inclusion initiatives ($2k) and general cost inflation.

b. The increase in IT costs is primarily due to various IT operating projects (EPCOR.com and JIRA replacement) in 2023 Test Year ($15k) and general cost inflation.

c. The increase in P&GA costs is primarily due to increases in the allocation percentage for EEDO. The cost driver for EEDO is net income and EEDO is anticipating earning its ROE for 2023 Test Year versus having lower earnings in 2022 Bridge Year as a result of there being a long time lag from EEDO's last cost of service filing in 2013.

Allocated Corporate Asset Usage Fees

EUI charges fees relating to general plant assets owned by EUI that are used in providing Corporate Shared Services to EPCOR business units. These fees are referred to as Corporate Asset Usage Fees. The categories of assets for which Corporate Asset Usage Fees are charged include the following:

- Leasehold Assets – disaster recovery and EPCOR Tower leasehold improvements benefitting employees in Corporate Shared Services departments that work at EPCOR Tower and support EUI subsidiaries including EEDO.

- Human Resources Information Systems (HRIS) - software application that is used by EUI's HR department to manage the employees of the EPCOR group, including functions such as recruiting, hiring, managing and paying employees (including the calculation of pensions, CPP, UIC, income tax and other payroll deductions).

- Information Services (IS) Infrastructure - IS assets include servers, electronic storage devices, information system networks, desktops and IS Applications.

- Financial Systems - represent the current financial application that is used to pay invoices, record and report financial information, prepare financial statements, calculate depreciation, purchase goods and services and manage project costs. The software application, Oracle Financials, uses modules that include Accounts Payable, Accounts Receivable, General Ledger, Purchasing, Projects and Fixed Assets.

- Furniture and Fixture Assets - represent furniture such as offices, workstations, chairs, tables, file cabinets and shelves used by employees in Corporate Shared Services departments.

The Asset Usage Fee for each category of corporate assets is comprised of two components: “return on” capital and “return of” capital (or depreciation expense). The return on capital component is calculated using the service recipient’s weighted average cost of capital (“WACC”).

EUI’s 2019 Actual – 2021 Actual, 2022 Bridge Year and 2023 Test Year’s Asset Usage Fees allocated to EEDO are shown in Table 4.4.2-14.

Table 4.4.2-14

Corporate Asset Usage Fees to EEDO

($)

		A	B	C	D	E
	Asset Category	**2019A**	**2020A**	**2021 A**	**2022 Bridge Year**	**2023 Test Year**
1	Leasehold Assets	5,274	4,936	6,111	4,443	4,451
2	HRIS	2,592	3,031	2,798	2,430	2,434
3	IS Infrastructure	101,786	77,926	-	96,689	105,351
4	Financial Systems	33,184	32,984	32,388	31,455	28,847
5	Furniture and Fixtures	4,241	2,187	2,603	2,189	2,446
6	Return on Assets	31,362	26,282	13,376	30,327	29,187
7	2021 inadvertent error	-	-	99,307	-	-
8	**Total EEDO**	**178,360**	**147,346**	**156,583**	**167,533**	**172,716**
9	Variance		(31,014)	9,237	10,950	5,183

The 2021 Actuals includes an inadvertent error in the calculation of IS Infrastructure costs and Return on Assets as amounts were missed in the allocation to EEDO. The correct amount of IS Infrastructure in the absence of this inadvertent error would have been $95,257 for IS Infrastructure and $17,426 for Return on Assets, which resulted in EEDO costs being too low by $99,307 as noted in row 7 of the table above.. These cost levels would make these values consistent with prior and go forward years.

The Corporate Asset Usage Fees from 2021 Actual to 2023 Test Year, after correcting for the inadvertent error noted in paragraph 135 above, remain flat, with increases primarily due to inflation

The overall costs for Corporate Asset Usage Fees from 2022 Bridge Year to 2023 Test Year remain flat, with increases primarily due to inflation.

2023 Test Year to 2013 OEB Approved

Table 4.4.2-15 outlines EEDO's 2013 Actual and 2023 Test Year Shared Service allocation costs.

Table 4.4.2-15
2013 Actual vs. 2023 Test Year – Shared Service Costs
($)

		A **2013A**	B **2023 Test Year**	C **Variance**	D **Variance %**
1	Collus PowerStream Solutions Corp.	974,448	N/A	(974,448)	N/A
2	Service Fee	132,000	N/A	(132,000)	N/A
3	Town of Collingwood	22,133	N/A	(22,133)	N/A
4	Collingwood Public Utilities Service Board	310,082	N/A	(310,082)	N/A
5	Affiliate Shared Services	N/A	790,070	790,070	N/A
6	Corporate Shared Services	N/A	875,084	875,084	N/A
7	**Total EEDO**	**1,438,663**	**1,665,154**	**226,491**	**16%**

The 2013 Actual for Town of Collingwood includes amounts for property maintenance and vehicle fuel. These costs are now directly incurred by EEDO.

The 2013 Actual Collingwood Public Utilities Service Board includes $216,000 for building lease charges. When EEDO was acquired by EPCOR in October 2018, the Town of Collingwood entered into a new lease agreement with EEDO. This lease is now treated as a Right of Use Asset and included in rate base. The 2013 Actual also includes $72,290 for shared employee charges which no longer exists and $21,792 for computer lease charges and EEDO now sources all computer hardware and software internally.

The 2013 Actual for Collus PowerStream Solutions Corp. includes 17 headcount which were allocated to EEDO at 55%, resulting in approximately 9.4 FTE allocated to EEDO. Since 2013, these FTEs were either embedded in EEDO, vacated and subsequently filled in EOUI/EOOMI or vacated and not filled. A high-level summary of the Collus PowerStream Solutions Corp. headcount included in 2013 Actual and what has happened with these positions compared to 2023 Test Year is provided below. Please see section 4.4.1 for further information of the headcount which were embedded in EEDO in 2016.

a. CEO position, one headcount, replaced by the Vice President, Ontario Region and the Director, Operations Ontario Region in EOOMI. In 2013 Actual the CEO position was allocated at 0.55 FTE to EEDO while the Vice President, Ontario Region and the Director, Operations Ontario Region are allocated at 0.7 FTE in total in the 2023 Test Year in Shared Services.

b. Manager HR position, one headcount, was vacated and not replaced. HR support is now provided by the Consultant, Human Resources in EOOMI. In 2013 Actual the Manager HR position was allocated at 0.55 FTE while the Consultant, Human Resources is allocated at 0.43 FTE in the 2023 Test Year in Shared Services.

c. Controller position, one headcount, was vacated and has not been replaced. In 2013 Actual the Controller position was allocated at 0.55 FTE and there is no corresponding cost in the 2023 Test Year for EEDO.

d. One Payroll/Benefits Coordinator position, one VP Operations position, one Billing & Regulatory Manager position, one CFO position, one Computer Systems and Network Technician in IT position, one System Support Technician IT position, one GIS Technician position, one Engineering Technologist position and six Billing and Collecting positions were embedded in EEDO in 2016.

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Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ 1,710,170	5.58%	$ 95,427.49	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 2,300,000	4.67%	$ 107,410.00	
3	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	1-Aug-12	25	$ 6,107,632	3.84%	$ 234,533.09	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 700,000	4.58%	$ 32,060.00	
Total							$ 10,817,802	4.34%	$ 469,430.57	

Notes

1. If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2. Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any subsequent update issued by the OEB.
3. Add more lines above row 12 if necessary.

Year 2014

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ 1,710,170	4.88%	$ 83,456.30	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 2,100,000	4.67%	$ 98,070.00	
3	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	1-Aug-12	25	$ 5,946,961	3.84%	$ 228,363.31	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 688,787	4.58%	$ 31,546.45	
Total							$ 10,445,918	4.23%	$ 441,436.06	

Notes

1. If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2. Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with
3. Add more lines above row 12 if necessary.

Year 2015

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ -	0.00%	$ -	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 1,900,000	4.67%	$ 88,730.00	
3	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	1-Aug-12	25	$ 5,780,010	3.84%	$ 221,952.40	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 677,055	4.58%	$ 31,009.10	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 975,000	2.76%	$ 26,910.00	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ 1,400,000	3.65%	$ 51,100.00	
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ 1,710,170	3.65%	$ 62,421.21	
Total							$ 12,442,235	3.87%	$ 482,122.70	

Notes

1. If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2. Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with
3. Add more lines above row 12 if necessary.

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ -	0.00%	$ -	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 1,700,000	4.67%	$ 79,390.00	
3	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	1-Aug-12	25	$ 5,606,535	3.84%	$ 215,290.93	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 664,778	4.58%	$ 30,446.84	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 925,000	2.76%	$ 25,530.00	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ 1,374,904	3.65%	$ 50,183.98	
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ 1,679,513	3.65%	$ 61,302.24	
Total							$ 11,950,730	3.87%	$ 462,143.99	

Notes

1. If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2. Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with
3. Add more lines above row 12 if necessary.

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ -	0.00%	$ -	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 1,500,000	4.67%	$ 70,050.00	
3	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	1-Aug-12	25	$ 5,426,279	3.84%	$ 208,369.10	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 651,933	4.58%	$ 29,858.51	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 875,000	2.76%	$ 24,150.00	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ 1,347,718	3.65%	$ 49,191.72	
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ 1,646,305	3.65%	$ 60,090.14	
8	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	10-Mar-17	10	$ 3,048,746	3.59%	$ 109,449.98	
Total							$ 14,495,981	3.80%	$ 551,159.45	

Notes

1. If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2. Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with
3. Add more lines above row 12 if necessary.

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ -	0.00%	$ -	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 1,300,000	4.67%	$ 60,710.00	
3	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	1-Aug-12	25	$ 5,238,978	3.84%	$ 201,176.76	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 638,491	4.58%	$ 29,242.91	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 825,000	2.76%	$ 22,770.00	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
8	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	3-Dec-18	30	$ 8,100,000	4.30%	$ 26,718.90	
Total							$ 16,102,469	2.12%	$ 340,618.57	

	Principal ($)	Rate (%)	Interest ($)	
Less: pro-rated principal for 2022	(7,478,630)			End of year issuance
True cost of debt	$ 8,623,839	**3.95%**	$ 340,619	

Notes

1. If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2. Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with
3. Add more lines above row 12 if necessary.

Year 2019

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ -	0.00%	$ -	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 1,100,000	4.67%	$ 51,370.00	
3	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	1-Aug-12	25	$ 5,044,357	3.84%	$ 193,703.31	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 624,427	4.58%	$ 28,598.77	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 775,000	2.76%	$ 21,390.00	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
8	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	3-Dec-18	30	$ 8,100,000	4.30%	$ 348,300.00	
Total							$ 15,643,784	4.11%	$ 643,362.08	

	Principal ($)	Rate (%)	Interest ($)	
Less: pro-rated principal for 2022	-			End of year issuance
True cost of debt	$ 15,643,784	**4.11%**	$ 643,362	

Notes

1. If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2. Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with
3. Add more lines above row 12 if necessary.

Year 2020

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ -	0.00%	$ -	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 900,000	4.67%	$ 42,030.00	
3	Government Agency Loan	OSIFA	Third-Party	Variable Rate	1-Aug-12	25	$ 4,842,130	3.84%	$ 185,937.78	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 609,711	4.58%	$ 27,924.77	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 725,000	2.76%	$ 20,010.00	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
8	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	3-Dec-18	30	$ 8,100,000	4.30%	$ 348,300.00	
9	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	1-Dec-20	30	$ 2,020,000	2.88%	$ 4,940.98	
Total							$ 17,196,841	3.66%	$ 629,143.52	

	Principal ($)	Rate (%)	Interest ($)	
Less: pro-rated principal for 2022	(1,848,438)			End of year issuance
True cost of debt	$ 15,348,402	**4.10%**	$ 629,144	

Notes

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with
3 Add more lines above row 12 if necessary.

Year 2021

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ -	0.00%	$ -	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 700,000	4.67%	$ 32,690.00	
3	Government Agency Loan	OSIFA	Third-Party	Variable Rate	1-Aug-12	25	$ 4,631,998	3.84%	$ 177,868.74	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 594,313	4.58%	$ 27,219.53	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 675,000	2.76%	$ 18,630.00	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
8	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	3-Dec-18	30	$ 8,100,000	4.30%	$ 348,300.00	
9	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	1-Dec-20	30	$ 2,020,000	2.88%	$ 58,176.00	
10	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	15-Dec-21	30	$ 2,000,000	3.41%	$ 2,989.59	
Total							$ 18,721,311	3.56%	$ 665,873.86	

Less: pro-rated principal for 2022	(1,912,329)			End of year issuance
True cost of debt	$ 16,808,983	**3.96%**	$ 665,874	

Notes

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with
3 Add more lines above row 12 if necessary.

Year 2022

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$ -	0.00%	$ -	
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 500,000	4.67%	$ 23,350.00	
3	Government Agency Loan	OSIFA	Third-Party	Variable Rate	1-Aug-12	25	$ 4,413,655	3.84%	$ 169,484.34	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 578,201	4.58%	$ 26,481.60	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 625,000	2.76%	$ 17,250.00	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$ -	3.65%	$ -	
8	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	3-Dec-18	30	$ 8,100,000	4.30%	$ 348,300.00	
9	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	1-Dec-20	30	$ 2,020,000	2.88%	$ 58,176.00	
10	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	15-Dec-21	30	$ 2,000,000	3.41%	$ 68,200.00	
11	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	31-Dec-22	30	$ 1,200,000	5.25%	$ 173	
Total							$ 18,236,856	3.90%	$ 711,241.94	

Less: pro-rated principal for 2022	(1,196,712)			End of year issuance
True cost of debt	$ 17,040,143	**4.17%**	$ 711,242	

Notes

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with
3 Add more lines above row 12 if necessary.

Year 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$	0.00%		
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 300,000	4.67%	$ 14,010	
3	Government Agency Loan	OSIFA	Third-Party	Variable Rate	1-Aug-12	25	$ 4,186,778	3.84%	$ 160,772	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 561,342	4.58%	$ 25,709	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 575,000	2.76%	$ 15,870	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$	3.65%		
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$	3.65%		
8	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	3-Dec-18	30	$ 8,100,000	4.30%	$ 348,300	
9	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	1-Dec-20	30	$ 2,020,000	2.88%	$ 58,176	
10	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	15-Dec-21	30	$ 2,000,000	3.41%	$ 68,200	
11	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	31-Dec-22	30	$ 1,200,000	5.25%	$ 63,000	
12	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	31-Dec-23	30	$ 1,200,000	5.03%	$ 165	End of year issuance
Total							$ 20,143,120	3.74%	$ 754,203	

Less: pro-rated principal for 2023	(1,196,712)			End of year issuance
True cost of debt	$ 18,946,408	**3.98%**	$ 754,203	

Collingwood PUC	244	58	65	367
Total	**550**	**338**	**741**	**1,629**

A reconciliation of cost drivers contributing to the increase in General & Administration costs is provided below:

2013T General & Admin	**1,380**
Shared services in G&A removed	(741)
Increase in EPCOR shared services	1,665
Inflation	285
Other	26
2023T General & Admin	**2,615**

i) No, the difference in shared service costs from 2013 to 2023 does not explain the increase in General and Administration costs.

ii) N/A

iii) See above for reconciliation of 2013T G&A to 2023T G&A

5-Staff-101
Ref: 5-Staff-56
2023 Cost of Capital Parameters

On October 20, 2022, the OEB issued a letter to all rate-regulated utilities and parties involved in cost of service based application, announcing updated cost of capital parameters for cost-based rates that have an effective date commencing in 2023. As approved by the OEB, the new deemed long-term (LT) debt rate for 2023 rate applications is 4.88%.[1]

The following table has been prepared by OEB staff based on the information that EPCOR Electricity Distribution Ontario provided in Exhibit 5 (and Chapter 2 Appendix 2-OB) of the application and the historical and current OEB Cost of Capital Parameters.

Date of Issuance		Term (years)	Principal	Rate EEDO Applied in Application	OEB Deemed LT Debt Rate (most current at the time of issuance of debt)
3-Dec-18	Actual	30	$8,100,000	4.30%	4.13%
1-Dec-20	Actual	30	$2,020,000	2.88%	2.85%
15-Dec-21	Actual	30	$2,000,000	3.41%	3.49%
31-Dec-22	Forecasted	30	$1,200,000	5.25%	4.88%
31-Dec-23	Forecasted	30	$1,200,000	5.03%	4.88%

The 2023 deemed LT debt rate of 4.88% is lower than the two estimated debt rates that EPCOR Electricity Distribution Ontario has applied to its affiliated LT debt instruments forecasted to be issued in December 2022 and December 2023. In the preamble to interrogatory 5-Staff-56, OEB staff documented the OEB's policy with respect to conditions when the deemed LT debt rate issued by the OEB would actual as a proxy or ceiling for the rate to be applied for rate-setting purposes. This includes when debt is issued by an affiliated company.

Question(s):

a) Please confirm or correct the entries in the table shown above.

EEDO Response:

Confirmed

b) Please confirm whether EPCOR Electricity Distribution Ontario will follow the OEB's policy to use the deemed LT debt rate as the ceiling on the rates of these two (2022 and 2023) debt instruments, as documented in EB-2009-0084 *Report*

[1] Ontario Energy Board, 2023 Cost of Capital Parameters, October 20, 2022

of the Board on the Cost of Capital for Ontario's Regulated Utilities, issued December 11, 2009 and as quoted in 5-Staff-56.

EEDO Response:

EEDO cannot follow the use of the deemed LT debt rate as the ceiling on the rates for the 2022 and 2023 debt instruments.

c) If the answer to part b) is no, please explain why EPCOR Electricity Distribution Ontario believes that the rate treatment for the forecasted 2022 and 2023 debt should not comply with the OEB's policy.

EEDO Response:

As noted in EEDO's response to 5-Staff-56, EEDO has discussed in detail the procedures it follows to help ensure that the ultimate actual debt rates used for EEDO are comparable to market-based rates on arms-length commercial terms.

EEDO also reiterates that it is not reasonable to have LT debt rates capped at a ceiling based on calculations prepared using data from September 2022, when actual debt issuances will not occur until well after September 2022 for both the 2022 and 2023 debt issuances.

EEDO has to issue debt based on the market conditions when the debt is actually taken out by EEDO. The components of LT debt rates, including underlying interest rates and Utility Bond Yield Spreads (or credit spreads) fluctuate constantly and the actual LT debt rates which EEDO will enter into will be based on the market conditions when EEDO places the LT debt. The market conditions may result in parameters above or below the data used in the OEB's October 20, 2022 Cost of Capital Parameters.

A clear example of this is the Government of Canada 30-year underlying rates. For the time period of October 3, 2022 to October 31, 2022 (i.e. the time since the OEB's data were collected up to September 30, 2022), the Government of Canada 30-year underlying rates ranged from 3.103% to 3.693% (based on ending Government of Canada 30-year rates for each day in this period). If EEDO had issued LT debt in this period, the underlying component of that debt could have been well in excess of the 3.231% Long Canada Bond Forecast in the OEB's calculation which would set the ceiling for affiliated debt to EEDO. This would result if EEDO not being able to recover this prudently incurred cost, not only for the upcoming cost of service period, but for the entire life of the LT debt issued. EEDO believes this would be an unfair result.

EEDO believes that the procedures to determine EEDO's LT debt rates are based on a market-based approach which would result in a market-based interest rate for the debt being issued by the utility.

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

reiterate that the onus is on the distributor that is making an application for rates to document the actual amount and cost of embedded long-term debt and, in a forward test year, forecast the amount and cost of new long-term debt to be obtained during the test year to support the reasonableness of the respective debt rates and terms.

The following guidelines are relevant with respect to the determination of the amount and cost of long-term debt for electricity distribution utilities.

The Board will primarily rely on the embedded or actual cost for existing long-term debt instruments. The Board is of the view that electricity distribution utilities should be motivated to make rational decisions for commercial "arms-length" debt arrangements, even with shareholders or affiliates.

In general, the Board is of the view that the onus is on the electricity distribution utility to forecast the amount and cost of new or renewed long-term debt. The electricity distribution utility also bears the burden of establishing the need for and prudence of the amount and cost of long-term debt, both embedded and new.

Third-party debt with a fixed rate will normally be afforded the actual or forecasted rate, which is presumed to be a "market rate". However, the Board recognizes a deemed long-term debt rate continues to be required and this rate will be determined and published by the Board. **The deemed long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances**. These circumstances include:

- For affiliate debt (i.e., debt held by an affiliated party as defined by the Ontario *Business Corporations Act, 1990*) with a fixed rate, the deemed long-term debt rate <u>at the time of issuance</u> will be used as a ceiling on the rate allowed for that debt.

- For debt that has a variable rate, the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. This applies whether the debt holder is an affiliate or a third-party.

- The deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.

- For debt that is callable on demand (within the test year period), the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. Debt that is callable, but not within the period to the end of the test year, will have its debt cost considered as if it is not callable; that is the debt cost will be treated in accordance with other guidelines pertaining to actual, affiliated or variable-rate debt.

- A Board panel will determine the debt treatment, including the rate allowed based on the record before it and considering the Board's policy (these Guidelines) and practice. The onus will be on the utility to establish the need for and prudence of its actual and forecasted debt, including the cost of such debt.

Deemed Long-term Debt Formula for Electricity Distributors

While the Board is of the view that greater reliance should be placed on embedded debt, including forecasts of the amount and cost of new debt expected to be incurred during the test year, the Board recognizes that there is a continuing need for a deemed long-term debt rate.

While there were no specific suggestions for how the deemed long-term debt rate should be calculated, **the Board sees merit in modifying the formula in a manner consistent with the changes adopted for the ROE adjustment formula**.

Specifically, the Board considers that **the deemed long-term debt rate for the test year should be an estimate based on the long (30-year) Government of Canada bond yield forecast plus the average spread between an A-rated Canadian utility bond yield and 30-year Government of Canada bond yield for all business days in the month three (3) months in advance of the (proposed) effective date for the rate changes**. This change is only in the source of the data, in the following ways:

4.5 Summary

The key elements of the Board's cost of capital policy are summarized in the following table.

Table 2: Components of the Board's Cost of Capital Policy

Capital structure	• 60% debt (56% long-term and 4% short-term) and 40% equity for electricity distributors. • Gas distributors, electricity transmitters and OPG will continue with approved capital structures.
Short-term debt rate	• Once a year, in January, obtain real market quotes from major banks, for issuing spreads over Bankers Acceptance rates for the cost of short-term debt. • The short term rate will be calculated as the average Bankers' Acceptance for the month 3 months in advance of the effective date for the rates, plus the spread for the year calculated above.
Long-term debt rate	• The deemed long-term debt rate will be based on the Long Canada Bond Forecast plus an average spread with an A-rated long-term utility bond yield). • Third-party embedded/actual debt with fixed rates, terms and maturity will get the actual rate. • Affiliate embedded/actual debt with fixed rates, terms and maturity will get the lower of actual and deemed debt rate at time of issuance. • Utility provides forecasts of new debt for a forward test year, where possible. New third-party debt will be accepted at the negotiated market rate. If a forecasted new rate is not available (i.e., due to timing), the deemed long-term debt rate may apply. • For new affiliated debt, the deemed long-term debt rate will be a ceiling on the allowed rate. The onus will be on the utility to demonstrate that the applied for rate and terms are prudent and comparable to a market-based agreement and rate on arms-length commercial terms. • Variable-rate debt will be treated like new affiliated debt. • Renegotiated or renewed debt will be considered new debt. • Where a utility has no actual debt, the deemed long-term debt rate shall apply.
Common equity return	• Refined formula-based ROE will be calculated as the base ROE + 0.5 X (change in Long Canada Bond Forecast from base year) + 0.5 X (change in the spread of (A-rated Utility Bond Yield – Long Canada Bond Yield) from the spread in the base year). This includes an implicit 50 basis points for transactional costs. • The ROE (and the short-term and long-term debt rates) will be based on data for the month 3 months in advance of the effective date for rates. • Reset formula for 2010: The base ROE in the refined formula will be calculated for 2010 as Long Canada Bond Forecast rate plus an ERP of 550 basis points, and reflects multiple, empirically supported, estimates provided in consultation which led to this report.

9.2 Establishment of New Deferral and Variance Accounts

EEDO is proposing the following accounts be established for use during the 5 year period covered by this Application, including the Test Year and the subsequent years covered under the proposed Price Cap IR Plan:

- Non-Utility Billing Variance Account ("NBDA"); and
- Recovery of Income Taxes Deferral Account ("RITDA").

EEDO applied the following criteria for the establishment of new deferral and variance accounts from the Filing Requirements for Electricity Distribution Rate Applications:

- Causation – The forecasted expense must be clearly outside of the base upon which rates were derived.
- Materiality – The forecasted amounts must exceed the materiality threshold of $50,000.
- Prudence – The nature of the costs and forecasted quantum must be reasonably incurred.

Non-Electricity Billing Deferral Account – NBDA

EEDO proposes to establish a NBDA for use during the Price Cap IR Term covered by this application. The purpose of the NBDA is for EEDO to record the difference between the amount of fixed billing costs attributable to non-electricity billing net of actual recoveries from the Town of Collingwood in the event the agreement to provide these services is terminated by the Town of Collingwood.

As discussed in Exhibit 4, section 4.1.2 EEDO provides non-electricity billing services to the Town of Collingwood. In the 2021 municipal budget,[8] the Town included a Directors recommendation to bring these service back in-house. Due to a shift in priorities driven by the COVID-19 pandemic,

[8] https://www.collingwood.ca/sites/default/files/uploads/documents/2021_final_budget_0.pdf , Town of Collingwood, 2021 Budget, page 61 of 103.

this business assessment did not take place. EEDO continues to have open dialogue with the Town about the continued provision of this service, but in the event that the service agreement to provide these services is terminated, EEDO will still be required to incur certain fixed billing costs in order to continue to provide these services to the utility customers (i.e. costs that will be incurred irrespective of the amount/level of customer billing activities). In EEDO's calculation of 2023 Test Year OM&A, approximately $200k of fixed billing & collecting costs were excluded from the distribution revenue requirement for billing services provided by outside vendors for activities such as meter reading, bill preparation, and bill fulfillment. The remaining portion of these non-electricity billing costs relate to employee time for providing billing services to the third party and EEDO is not seeking to include these costs in this deferral account. Substantially all of the outside vendor billing costs are fixed in nature and would continue to be incurred if non-electricity billing services were terminated. The costs being charged to third parties result in OM&A savings to EEDO ratepayers that would not otherwise exist.

EEDO is proposing to calculate simple interest on the NBDA balance, at the applicable Board approved short-term interest rate, on the monthly opening balances using the interest rate methodology as approved in EB-2006-0117.

Future audited balances in this account, together with any carrying charges, will be brought forward for approval for disposition on an annual basis.

A draft Accounting Order for the NBDA is provided in Exhibit 9, Appendix E.

Recovery of Income Taxes Deferral Account - RITDA

EEDO proposes to establish a RITDA for use during the Price Cap IR Term covered by this Application. The purpose of the RITDA is for EEDO to record the difference between the zero cash income taxes included in the revenue requirement proposed in this Application and the actual cash income taxes for its EEDO operations (as calculated at the tax rate currently in place at the time of this Application) throughout the Price Cap IR Term, commencing in the year 2023.

As noted in Table 6.2-1 of Exhibit 6, Tab 1, Schedule 1 the income taxes payable for the Test Year is zero. However, as loss-carryforwards balance for regulatory purposes related to the utility are used during the Price Cap IR Term, EEDO may pay substantial cash taxes once the utility's loss-carryforwards for regulatory purposes are utilized against taxable income incurred during the Price Cap IR Term. EEDO expects that income taxes payable will exceed the materiality threshold during the Price Cap IR Term.

Cost of Service methodology allows for the recovery of taxes in the Test Year. In this Application, taxes included in the revenue requirement are zero in the 2023 Test Year. Whereas the year 2023 sets the base for future years' revenue under Price Cap IR, and whereas income taxes payable in subsequent years of the Price Cap IR Plan are expected to be a material positive amount, embedding such a minimal tax amount in the base revenue requirement does not allow for recovery of taxes in 2023 and beyond. Establishing the requested deferral account will enable the recording and fair recovery of incurred income tax expenditures over the Price Cap IR Term once the loss carry-forward balance for regulatory purposes is fully utilized.

As noted in Table 6.2-2 of Exhibit 6, Tab 1, Schedule 1, EEDO's legal entity loss carry-forward balance has $1,266,169 of non-utility cost loss carry-forward balances. This amount will be removed from the loss carry-forward balances for regulatory purposes such that the loss carry-forward balance going into the 2022 Bridge Year will be the sum of rows 1 through 3 from table 6.2-2 of Exhibit 6, Tab 1, Schedule 1 (i.e. $3,017,883 + $181,710 - $1,266,127 = $1,933,466). EEDO proposes that for the purposes of determining the amount to record in the RITDA for a given year that the taxable income (or losses) for the 2022 Bridge Year and any subsequent period will reduce (or increase) this loss carry-forward balance for regulatory purposes and in the year that the loss carry-forward balances is fully utilized. And for subsequent years, that amounts are added to the RITDA based on the taxable income for years once the loss carry-forward balance is fully utilized.

EEDO proposes that for the purposes of determining the amount to record in the RITDA, the actual cash income taxes each year are calculated based on the tax rate in place at the time of this Application. This will ensure no double counting of a recovery between the RITDA and Account 1592 – PILS and Tax variances due to changes in legislation.

EEDO is proposing to calculate simple interest on the RITDA balance, at the applicable Board approved short-term interest rate, on the monthly opening balances using the interest rate methodology as approved in EB-2006-0117.

Future audited balances in this account, together with any carrying charges, will be brought forward for approval for disposition on an annual basis.

A draft Accounting Order for the RITDA is provided in Exhibit 9, Appendix D.

9.3 Lost Revenue Adjustment Mechanism Variance Account

The LRAMVA is a retrospective adjustment designed to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs. The OEB established Account 1568 as the LRAMVA to capture the difference between the OEB-approved CDM forecast and actual results at the customer rate class level.

EEDO has previously disposed of the LRAMVA balance as of December 31, 2020.

The 2021 CDM Guidelines require distributors filing an application for 2023 rates to seek disposition of all outstanding LRAMVA balances related to previously established LRAMVA thresholds (i.e, thresholds established in a distributor's previous cost of service proceeding). As a result, EEDO is seeking outstanding LRAMVA balances for 2021 and 2022 as part of this application.

EEDO had new cost of service rates approved for 2013. This was the first COS filing where the load forecast incorporated the anticipated CDM savings related to the new CDM targets assigned to distributors.

EEDO has calculated the LRAMVA for 2021 and 2022, based on the Board's guidance as published in the April 18, 2022 Filing Requirements. Consistent with the 2020 disposition, this application includes a change to the data source used (Participation and Cost reports) as the IESO is no longer provided a workbook of annualized verified results to LDC's due to the conclusion of the Conservation First Framework. To calculate net savings values at the project level, EPCOR used results from the IESO's 2017 program evaluation (e.g., net-to-gross values and gross realization rates). Of note, EEDO has only included one additional project in the 2021 claim as all other projects have been included in previous applications. The information from this

Exhibit 6 – Revenue Requirement

6-Staff-57
Tax Return
Ref: Exhibit 6 / Tab 1 / Schedule 1 / page 10

Please provide a copy of 2021 tax return. If the final return is not available, please provide the draft return and indicate whether changes are expected to the draft return.

EEDO Response:

See attachment 6-Staff-57_2021 Tax Return.pdf

6-Staff-58
PILs
Ref: Exhibit 6 / Tab 1 / Schedule 1 / page 11
Exhibit 9 / Tab 1 / Schedule 1 / pages 25-27

Preamble:

Table 6.2-2 in Exhibit 6 shows the tax losses carry-forward for regulatory purposes available to be used for 2023 to be $2,680,706. EPCOR Electricity Distribution Ontario indicated that it anticipates to use up the loss carry-forward during 2023 to 2027.

EPCOR Electricity Distribution Ontario states that:

> As a result of expecting to use the loss carry-forward for regulatory purposes balance prior to its next cost of service filing, EEDO is requesting the establishment of a deferral account to track the use of the loss carry-forwards for regulatory purposes and to include any tax expense incurred in the 2023 to 2027 period once the loss carryforward for regulatory purposes balance is fully utilized.

Question(s):

a) Please explain the main drivers that generated the tax loss carry-forwards for regulatory purposes (i.e. drivers of the 2018 to 2022 tax losses).

EEDO Response:

The primary drivers that contributed taxable loss carry-forwards include higher O&M costs, judicial inquiry costs, higher interest expense due to increased capital additions and higher tax depreciation expense versus accounting depreciation expense (CCA rates are higher than accounting depreciation rates).

b) EPCOR Electricity Distribution Ontario indicated that it has excluded losses relating to the judicial inquiry from tax loss carry-forwards for regulatory purposes. Please confirm that the regulatory tax loss carry-forward does not reflect any other material non-regulatory amounts (e.g. CCA on goodwill that may have been included in taxable income). If not confirmed, please identify the material non-regulatory amounts that impacted the tax loss carry-forward.

EEDO Response:

Confirmed.

c) Please update the table as appropriate, for the finalization of the 2021 tax return, any updates to the 2022 tax loss carry-forward forecast, and any other material non-regulatory amounts as referenced in response to part b above.

EEDO Response:

Updated table 6.2-2 is provided below.

Updated Table 6.2-2
Reconciliation of Loss Carry-Forward Balances for Regulatory Purposes
($)

		A **2023** **Test Year**
1	Loss carry-forward per 2020 tax return	3,017,883
2	2021 losses	332,610
3	Judicial Inquiry costs incurred in 2018 to 2021	(1,266,169)
4	2022 losses	806,407
5	Loss carry-forward balance to 2023	2,890,731

d) Please provide the annual forecasted taxable income, tax loss carry-forward and taxes payable for 2023 to 2027.

Please indicate the CCA rule EPCOR Electricity Distribution Ontario anticipates to use in its tax return for each year from 2023 to 2027 (e.g. legacy half-year rule, two-times the half-year rule)

EEDO Response:

Forecast 2023 to 2027 taxable income for regulatory purposes is as follows:

2023 – $112,666

2024 - $199,693

2025 - $575,342

2026 - $740,173

2027 - $860,919

EEDO intends to continue to use the legacy half-year rule.

6-Staff-59
Account 1592
Ref: Exhibit 6 / Tab 2 / Appendix B – PILs Workform
Exhibit 9 / Tab 1 / Schedule 1 / pages 25-27

Preamble:

In Schedule 8 of the PILs Workform for the test year, CCA is calculated using the legacy rule (i.e. the half-year rule) instead of using accelerated CCA rules.

EPCOR Electricity Distribution Ontario has proposed to establish a new account called the Recovery of income Taxes Deferral Account, which is to record the difference between the zero PILs included in the revenue requirement proposed and the actual taxes paid (as calculated at the tax rate currently in place at the time of this Application).

Question(s):

a) Please explain EPCOR Electricity Distribution Ontario's expectation for Account 1592, Sub-account CCA Changes during 2023 to 2027, given its expectation of CCA claims in its tax return as noted in response to 6-Staff-58 (e.g. whether there will be a balance in the account for particular years, how the balance will be determined).

EEDO Response:

EEDO intends to take CCA based on the legacy rules for all years and as such does not expect aby Account 1592, Sub-account CCA changes during 2023 – 2027.

b) Please explain how Account 1592, Sub-account CCA Changes will interact with the proposed Recovery of Income Taxes Deferral Account, and how will EPCOR Electricity Distribution Ontario ensure that there is no double counting between the two accounts.

EEDO Response:

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2017-0373 AND EB-2017-0374

THE CORPORATION OF THE TOWN OF COLLINGWOOD AND EPCOR COLLINGWOOD DISTRIBUTION CORP.

Applications for approval of share acquisition transactions and related matters

BEFORE: Ken Quesnelle
Presiding Member and Vice-Chair

Christine Long
Member and Vice-Chair

Cathy Spoel
Member

August 30, 2018

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1 INTRODUCTION AND SUMMARY

This is the Decision of the Ontario Energy Board (OEB) regarding an application filed by the Corporation of the Town of Collingwood (the Town) and EPCOR Collingwood Distribution Corporation[1] (EPCOR) (collectively, the Applicants). The Applicants' application requested that the OEB approve two share purchase transactions that would result in EPCOR becoming the new owner of Collus PowerStream Corporation (CollusLDC), the local electricity distribution company serving Collingwood, Stayner, Creemore and Thornbury. If approved, this transaction would provide EPCOR with ownership of its first electricity distributor in Ontario.

The two sequential share purchase transactions proposed by the Applicants that require OEB approval are as follows. First, the Town proposes to purchase the shares of Collingwood PowerStream Utility Service Corporation (CollusHoldco), the holding company of CollusLDC, that are currently owned by Alectra Utilities Corporation (Alectra Utilities). Second, the Applicants propose that EPCOR will then purchase all of the shares of CollusHoldco from the Town. These transaction approval requests were made pursuant to Section 86 of the *Ontario Energy Act, 1998*[2] (the Act) which requires a transmitter or distributor to obtain leave of the OEB before disposing of its distribution or transmission system or amalgamating with another corporation.

Additionally, the Applicants seek OEB approval for a one percent reduction in CollusLDC's current electricity distribution rates for residential customers and that this reduction be in effect for the first five years following the transaction.

The application proposes to defer rate rebasing for five years following completion of the transaction. Lastly, the application requests approval to continue to track costs to the regulatory asset accounts currently approved by the OEB for CollusLDC and to seek disposition of their balances at a future date.

The OEB has applied the "no harm" test in assessing this application and has concluded that the proposed transactions meet that test. The OEB therefore approves the application as filed. The OEB also approves the additional requests made by the Applicants as further described in this Decision.

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[1] EPCOR Utilities Inc. (EUI) is a corporation incorporated under the laws of the Province of Alberta and is the parent company to EPCOR. EPCOR is a corporation incorporated under the laws of the Province of Ontario.
[2] S.O. 1998, c. 15 Schedule B

2 THE PROCESS

CollusLDC, a wholly-owned subsidiary of CollusHoldco, has a distribution system that serves 16,864[3] residential and general service customers in Collingwood, Stayner, Creemore and Thornbury. Currently, CollusHoldco is owned jointly on a 50:50 basis by the Town and Alectra Utilities.

To facilitate the proposed transaction, the Town intends to purchase Alectra Utilities' 50% interest in CollusHoldco for the purchase price of $13 million and other terms.[4] Following that transaction, the Town proposes to sell all of the issued and outstanding shares of CollusHoldco to EPCOR for the purchase price of $36.8 million. The $36.8 million purchase price includes a cash payment of $25 million plus the assumption of debt and working capital. The premium proposed to be paid by EPCOR for CollusHoldco is approximately $17.1 million. For each of these transactions, the Applicants' seek OEB approval under Section 86 of the Act.

Additionally, the Applicants also seek OEB approval of the following:

- A 1% reduction to the current base residential distribution rate (exclusive of rate riders) to be in effect for the first five years following the transactions.
- To defer the rate rebasing period of CollusLDC for five years from the date of closing of the proposed transactions.
- To continue to track costs to the regulatory asset accounts currently approved for CollusLDC and to seek disposition of their balances at a future date.
- Such further and other relief as the OEB may consider appropriate.

The Applicants have selected a five year deferred rebasing period. During this period, the Applicants state that the rates of customers of CollusLDC will be adjusted using the Price Cap Incentive Rate Mechanism.

Process

The OEB determined that the application would be subject to a combined public hearing and issued a Notice of Application and Hearing on February 13, 2018 inviting interested parties to register as intervenors or file a letter of comment with the OEB. School Energy Coalition (SEC) applied for intervenor status and eligibility for cost awards. The OEB approved SEC and confirmed its eligibility to apply for an award of costs.

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[3] 2016 OEB Yearbook
[4] The purchase price is subject to adjustments after closing for working capital, net fixed assets, regulatory accounts and long-term debt.

In Procedural Order No. 1, issued on April 4, 2018, the OEB provided for interrogatories on the application to be filed by April 19, 2018 and responses to be filed by May 3, 2018.

During the interrogatory process, three letters of comment related to the application were received by the OEB.

Letter of Comment #1

> Mr. Ian Chadwick submitted a letter of comment on May 2, 2018 citing concerns regarding the level of public engagement in the proposed sale of CollusLDC to EPCOR. On May 11, 2018, Mr. Chadwick submitted an addendum to his May 2, 2018 letter of comment where he highlighted his concerns regarding responses from the Applicants to interrogatories and further expressed his concerns regarding the lack of public involvement in the decision-making process to sell CollusLDC.

Letter of Comment #2

> On May 7, 2018, Mr. Kevin Lloyd filed a letter of comment with the OEB citing the lack of business rationale to support or oppose the sale of CollusLDC to EPCOR and conveyed his concerns regarding the transparency of the decision-making process to sell CollusLDC.

Letter of Comment #3

> On May 10, 2018, the OEB received a letter of comment from Mr. Rick Lloyd. Similar to the other letters of comment received, Mr. R. Lloyd cited that many of the discussions and decision-making processes to sell CollusLDC were not transparent and did not duly engage the public. As a result, Mr. R. Lloyd expressed his concern regarding the sale of CollusLDC to EPCOR.

Both Mr. Chadwick and Mr. R. Lloyd also requested that the application be put on hold or have the decision delayed until the Town's council judicial inquiry into the 2012 sale of CollusHoldco shares[5] is completed.

[5] In OEB Decision and Order EB-2012-0056, dated July 12, 2012, the OEB approved the sale by the Town of 50% of its shares in CollusHoldco to Powerstream Utility Services Corporation (now Alectra Utilities).

The OEB issued responses on May 25, 2018 to the letters of comment received from Mr. Chadwick, Mr. K. Lloyd and Mr. R. Lloyd. In the response letters, the OEB highlighted the scope of review with respect to applications relating to mergers, acquisitions, amalgamations and divestitures (MAADs). Further, the OEB clarified that issues relating to the overall merits or rationale for the Applicants’ consolidation plans and the negotiating strategies or positions of the parties to the transaction are not considered in a MAADs application. The transparency of the hearing process for a MAADs application was also highlighted by the OEB in the response letters. Specifically, these letters affirmed that any CollusLDC ratepayer with concerns related to the Applicants meeting of the “no harm” test is free to participate and make related submissions to the OEB.

Procedural Order No. 2 was issued by the OEB on June 1, 2018. In this procedural order, a schedule was set for the filing of submissions and reply submissions. In accordance with Procedural Order No. 2, submissions were filed by OEB staff and SEC on June 18, 2018 while the Applicants provided reply submissions on June 29, 2018.

3 REGULATORY PRINCIPLES

3.1 The "No Harm" Test

The OEB applies the "no harm" test in its assessment of MAADs applications.[6] The OEB considers whether the "no harm" test is satisfied based on an assessment of the cumulative effect of the transaction on the attainment of its statutory objectives. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.

The statutory objectives to be considered are those set out in Section 1 of the Act.

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

    1.1. To promote the education of consumers.

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

While the OEB has broad statutory objectives, in applying the "no harm" test the OEB has focused on the objectives that are most directly relevant to the impact of the proposed transaction, namely, price, reliability and quality of electricity service to customers, as well as the cost-effectiveness, economic efficiency and financial viability of the consolidating utilities.

[6] The OEB adopted the "no harm" test in a combined proceeding (RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257) as the relevant test for determining applications for leave to acquire shares or amalgamate under section 86 of the Act and it has been subsequently applied in applications for consolidation.

The OEB considers this an appropriate approach, given the performance-based regulatory framework under which regulated entities are required to operate and the OEB's existing performance monitoring framework.

3.2 OEB Policy on Rate-Making Associated with Consolidations

To encourage consolidations, the OEB has put in place policies on rate-making that provide consolidating distributors with an opportunity to offset transaction costs with savings achieved as a result of the consolidation. The OEB's 2015 Report[7] permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction. Although the transaction proposed by the Applicants is not a true consolidation, as is further described in latter sections of this Decision, the principle of a deferred rebasing period is none-the-less relevant to this Decision.

The OEB's Handbook[8] sets out that the extent of the deferred rebasing period is at the option of the distributor and no supporting evidence is required to justify the selection of the deferred rebasing period. Consolidating entities must, however, select a definitive timeframe for the deferred rebasing period. This is to allow the OEB to assess any proposed departure from this stated plan. The Handbook states that when a consolidated entity has opted for a deferred rebasing period, it has committed to a plan based on the circumstances of the consolidation and that if it seeks to amend the deferred rebasing period, the OEB will need to understand whether any change to the proposed rebasing timeframe is in the best interest of customers.

The 2015 Report requires consolidating entities that propose to defer rebasing beyond five years to implement an earnings sharing mechanism for the period beyond five years to protect customers and ensure that they share in increased benefits from consolidation.

[7] EB-2014-0138 Report of the Board on Rate-making Associated with Distributor Consolidation, March 26, 2015.
[8] Handbook to Electricity Distributor and Transmitter Consolidation, January 19, 2016, pp. 12-13.

4 DECISION ON THE ISSUES

4.1 Application of the "No Harm" Test

Price and Rate Order

In its review of a consolidation proposal, the OEB reviews the underlying cost structures of the consolidating utilities. The proposed transactions in this application are not a distributor consolidation, per se, but the impact on the customers being acquired by EPCOR must meet the same "no harm" test as would apply for a distributor consolidation transaction. As distribution rates are based on a distributor's current and projected costs, the OEB has stated that it is important for the OEB to consider the impact of a transaction on the cost structure of the applicants both now and in the future.[9]

The Handbook sets out that if a premium has been paid above the historic value, this premium is not recoverable through distribution rates and no return can be earned on the premium. Shareholders are permitted to recover the premium over time through savings generated from efficiencies of the consolidated entity. The OEB has stated that in considering the appropriateness of the purchase price or the quantum of the premium that has been offered, only the effect of the purchase price on the underlying cost structures and financial viability of the regulated utilities will be reviewed.[10]

The Applicants have agreed on two separate, but related, share acquisitions involving the sale of CollusHoldco. In the initial transaction, the Town intends to purchase the respective 50% of the issued and outstanding shares in CollusHoldco owned by Alectra Utilities for the purchase price of $13 million. In the second transaction, the Applicants propose that the Town will sell all of the issued and outstanding shares of CollusHoldco to EPCOR for $36.8 million. This includes a cash payment of $25 million plus the assumption of debt and working capital. The premium to be paid by EPCOR is approximately $17.1 million.

The Applicants have selected a five-year deferred rebasing period from the closing of the proposed transactions, and have stated that rates for CollusLDC's customers will be adjusted based on the Price Cap Incentive Rate Mechanism during this period.

EPCOR has proposed a negative rate rider for CollusLDC's residential customers, the effect of which would be a 1% reduction in residential customers' base distribution

[9] Handbook, p. 6
[10] Handbook, p. 8

delivery rates. This negative rate rider would be effective for the first five years following the transaction, although rates would continue to be adjusted by the price cap incentive rate mechanism. The cost of the rate rider, as proposed by EPCOR, is expected to be approximately $50,000 per year ($250,000 over the five year period).[11] The Applicants have confirmed that they will not seek to recover this in rates and have shown, in response to interrogatories, that this cost is to be recovered from anticipated productivity gains during the deferred rebasing period.[12]

In SEC's submission, it is proposed that the OEB approve the application subject to the condition that the 1% negative rate rider for residential customers be expanded to include all classes of CollusLDC customers.[13] Further, SEC submitted that it is not the responsibility of the Town to set just and reasonable rates, and it is not their prerogative to allocate the benefits of the transaction between classes of CollusLDC customers.[14] In its reply submission, EPCOR highlighted that the 1% negative rate rider for residential customers was a result of negotiations in the commercial transaction between the Town and EPCOR. EPCOR also submitted that while OEB approval is required for the 1% negative rate rider, the condition of expanding the rider to all classes of CollusLDC customers, as put forth by SEC, should not occur. EPCOR states that the OEB's mandate allows it to examine the transaction before it and that the OEB does not have the authority to affect the terms of a previously negotiated commercial transaction.

In OEB staff submissions, concerns were raised regarding the applicability of the OEB's rate-making policies in the circumstances of the proposed share acquisitions. OEB staff submitted that in the event that rate-making policies in the Handbook should not apply to the subject scenario (since there is no consolidation in the electricity distribution sector arising from this application) an alternative approach needs to be taken. As an alternative, CollusLDC could avail itself to the OEB's Annual Incentive Rate Index (Annual IR) option, where it would file for an annual rate application but not seek the rate increase to base distribution rates that is established by the OEB's formula. In its reply submission, EPCOR stated its view that if the OEB were to develop rate-making policies for new entrants in Ontario's electricity distribution sector, such an undertaking is more appropriately developed through an OEB-initiated process. In the absence of a clear indication that the Handbook and associated rate-making policies should not apply

[11] OEB Staff IR 13
[12] OEB Staff IR 1(a)
[13] SEC Submission at 'Conclusion', p. 5
[14] SEC Submission at 'Price and Rate Order', p. 4

to new entrants, EPCOR further submitted that the Handbook rate-making policies associated with consolidations should apply to the share acquisition by EPCOR.[15]

OEB Findings

The OEB has determined that the “no harm” test is the appropriate means to evaluate the transactions proposed in the application. The OEB is satisfied that the proposed transactions meet the “no harm” test and therefore approves both share purchase transactions put forth by the Applicants. Specifically, and pursuant to Section 86 of the Act, the OEB grants approval for the Town to purchase Alectra Utilities’ 50% interest in CollusHoldco. The OEB also grants approval of the Town’s subsequent selling of all issued and outstanding shares of CollusHoldco to EPCOR.

The OEB’s decision regarding the transactions is premised on the evidence submitted by the Applicants.

The OEB does not consider temporary rate decreases proposed by applicants, and other such temporary provisions, to be demonstrative of “no harm” as they are not supported by, or reflective of the underlying cost structures of the entities involved and may not be sustainable or beneficial in the long term.

Specifically, the OEB places importance on understanding how, post rebasing deferral period, the applicants forecast the current costs or rates of the utility will be impacted by the proposed transaction. The purpose of which is to consider the long-term effect of the consolidation and the implications on customers and the financial sustainability of the sector.

In the evidence the Applicants state:

> “…EPCOR expects to generate targeted economies and efficiencies as a result of this acquisition. The cumulative impact of these economies and efficiencies are expected to result in a reduced cost structure for CollusLDC over the long term. ***It is expected that this will be reflected in a revenue requirement that is lower than it would have been in the absence of this acquisition when EPCOR files its Rate Application for the period after the five year deferred rebasing period*** [emphasis added].[16]”

When applying the “no harm” test to an application, the OEB does not consider if another proposal would provide greater benefit to customers. SEC’s proposal to expand

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[15] EPCOR Collingwood Distribution Corp. Reply Submission, p. 4
[16] Application, p. 30

the negative rate rider goes beyond applying the “no harm” test as it goes beyond the proposal put forth by the Applicants. As a result, the OEB will not consider the expansion of the 1% negative rate rider beyond the residential customer class as put forth by SEC.

The OEB accepts EPCOR’s argument on its interpretation of the rate treatment outlined in the Handbook being applicable to this transaction.

Economic Efficiency and Cost Effectiveness

In the review of a MAADs application, the OEB examines the impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity).[17] This review is based on an applicant’s identification of the various aspects of utility operations where it expects sustained operational efficiencies, both quantitative and qualitative. According to the evidence, EPCOR expects to generate targeted economies and efficiencies as a result of the proposed acquisition. OM&A cost savings arising from the proposed transaction of approximately $185,000 are forecast for 2020, with cost savings expected to rise to $464,000 by 2024 – relative to the forecasted OM&A costs under the status quo (i.e. in the absence of the transaction).[18] EPCOR submitted that operational efficiencies are expected from a reorganization of CollusLDC leadership and administrative functions. As the transaction proposed in the application is not a physical consolidation, EPCOR notes that no anticipated capital savings are expected.

OEB staff submitted that the proposed transaction can reasonably be expected to result in cost structures that are lower than under the status quo in the long-term. Both EPCOR and the Town are in agreement with OEB staff’s submission and maintain that the effect of the proposed transactions on underlying cost structures will be positive. Specifically, the Applicants contend that customer costs will not increase as a result of the proposed transactions, and that the proposed transactions will have a positive effect on the economic efficiency and cost effectiveness of the utility.[19] OEB staff also submitted that EPCOR should be required to demonstrate, at the time it files a Cost of Service application, how the efficiencies expected from the proposed transaction have resulted in lower costs to serve CollusLDC customers relative to the status quo.

[17] Handbook, p. 8
[18] OEB Staff IR 1(b)
[19] The Corporation of the Town of Collingwood Reply Submission, p. 4

OEB Findings

Based on the Applicants' statement that the economies and efficiencies introduced by the consolidation are expected to result in lower revenue requirements in the future, the Applicants have demonstrated reasonable consideration for the long-term impacts of the transaction on customers.

The OEB has examined the impact that the proposed transaction will have on the economic efficiency and cost effectiveness of CollusLDC, and has determined that the "no harm" test has been met.

The OEB will not require EPCOR to file evidence to demonstrate how the efficiencies expected from the transaction have produced savings in its first Cost of Service Application. The evidence of projected savings in this application support a finding that there is a reasonable expectation that customers will not be harmed in the immediate and long term. The evidence filed in this application will be available to interested parties in a future cost of service application if it is relevant to the rates proposed at that time.

Service Quality and Reliability

In considering the impact of a proposed transaction on the quality and reliability of electricity service, and whether the "no harm" test has been met, the OEB is informed by the metrics provided by the distributor in its annual reporting to the OEB and published in its annual scorecard.[20] The Applicants provided SAIFI and SAIDI statistics for CollusLDC[21] demonstrating acceptable levels of reliability, and also showed that both CollusLDC's and EUI's customer service levels exceed the targets established by their respective regulators. EPCOR stated that it is committed to meet or exceed current CollusLDC reliability standards.[22]

When asked through interrogatories by SEC whether the commitment to reliability standards should be a condition of application approval, the Applicants stated that it would be "a more onerous condition than that which any other LDC within Ontario operates".[23] Despite the Applicants' contention, SEC submitted that, with regards to both service quality and reliability measures, CollusLDC should maintain or improve upon its current performance and that these performance objectives should be included

[20] Handbook, p. 7
[21] Application, Figure 8/p. 33 and Figure 9/p. 34
[22] Application, p. 13
[23] SEC Submission, p. 3

as a condition of application approval.[24] As EPCOR, and its parent EUI are new entrants into the Ontario electricity distribution sector, SEC believes that by making this a condition of approval the OEB would signal the level of commitment and performance that is expected of EPCOR in Ontario.

Through their submission, EPCOR confirmed a commitment to retaining all current CollusLDC staff for two years and EPCOR stated that it has no plans to modify the roles, functions or immediate reporting structure of front-line staff directly responsible for system maintenance, service, and reliability.[25] It was also stated that as EPCOR does not currently own an electrical distribution company in Ontario, it expects to retain current employees for a period exceeding the two-year contractual commitment.[26] Based on the evidence and interrogatory responses provided, specifically EPCOR's commitment to retaining internal capability and institutional knowledge, OEB staff submitted that EPCOR can reasonably be expected to maintain current service quality and reliability standards.

OEB Findings

The OEB finds that it is reasonable to expect the service levels of CollusLDC to be maintained. To ensure that service levels are maintained following the transaction, the OEB will rely on ongoing monitoring to detect and respond if there is an unacceptable decline in service levels. The condition of approval put forth by SEC that would require EPCOR to meet or exceed both reliability and service quality metrics goes beyond the "no harm" test by compelling an improvement, and is therefore not appropriate.

Financial Viability

During a MAADs proceeding, the impact of a proposed transaction on an acquiring utility's financial viability, or on the financial viability of a consolidated entity in the case of a merger, is assessed by the OEB. The OEB's primary considerations in this regard are the effects of the purchase price, including any premium paid above the historic (book) value of the assets involved and the financing of incremental costs (transaction and integration costs) to implement the consolidation transaction.[27]

The purchase price agreed upon by the Applicants is $36.8 million, which includes a premium of $17.1 million. EPCOR has indicated that incremental transaction and

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[24] Ibid.
[25] This includes field crews, customer service, billing and other customer facing functions.
[26] Application, p. 35
[27] Handbook, p. 8

transition costs amount to $760,000, which includes $300,000 for EPCOR's integration costs and $360,000 being paid by EPCOR for the Town's transaction costs, redevelopment of the public waterfront lands, and expenses incurred by the Town in connection with the Town's assignment and assumption of financing agreements.

EPCOR stated that EUI will provide funding to complete the share purchase and confirmed that EUI has the financial capacity as the consideration paid will not have a material impact on EUI's financial position. The amount being paid for CollusLDC ($36.8 million) represents less than 0.4% of EUI's total assets.[28]

OEB staff noted that the 2019 pro-forma financial statement for CollusLDC filed with the application included one-time transaction costs and reflected a marked increase in interest expense from $570,000 in the 2016 Financial Statement to $1.1 million in the pro-forma statement. This observation was questioned by OEB staff through interrogatories. In response, EPCOR restated the 2019 pro-forma financial statement, confirming that it would not include the incremental inter-company debt sourced to fund the premium on CollusLDC's balance sheet. Further, EPCOR confirmed that the restated financial statement did not include any of the transaction costs highlighted earlier.

SEC raised concerns regarding the premium of $17.1 million that is to be paid in the transaction. SEC submitted that the premium appears to be too large to be recoverable in any way, without resorting to including it in rates, given the current CollusLDC annual income level of $601,000.[29] Also in its submission, SEC noted that it was unable to reconcile the stated premium with the CollusLDC Financial Statements filed with the application. According to SEC, the premium – i.e., the amount paid above the book equity – is in the order of $2.3 million. SEC submitted that a premium of $2.3 million would be manageable within the future income statements of CollusLDC, without any impact on rates. The Applicants did not provide a reply argument pertaining to SEC's submission on the premium.

OEB Findings

Given the financial position of EUI, and the Applicants' confirmation that EUI will provide funding to complete the share purchase, the OEB does not consider there to be any inherent risk to the financial viability of CollusLDC post-transaction. As a result, from the perspective of financial viability, the OEB confirms that the "no harm" test has been met.

[28] Application, pp. 39-40
[29] SEC Submission, p. 2

Assurance that there are no costs related to the premium paid for the acquisition in future rates can be achieved through examination when new rates are proposed.

Other Matters

Distribution System Plan (DSP) and Potential Incremental Capital Module (ICM)

The last Cost of Service review of CollusLDC was for 2013 rates. In 2017, CollusLDC was due to rebase its rates but requested a deferral of rebasing in 2017 due to a need for additional time to prepare its DSP. In 2018, CollusLDC also requested a deferral, owing to the proposed acquisition by EPCOR.[30] The application referenced a DSP for 2018-2022 for CollusLDC, which EPCOR has reviewed and finds reasonable.

EPCOR has stated that it may apply for an ICM during the deferred rebasing period, if required. OEB staff submitted that it does not oppose this proposal, however, OEB staff stated that there may be some uncertainty on the availability of the ICM given that the OEB’s consolidation policies may not apply for the transactions outlined in this application.

OEB Findings

The OEB has found that its policies outlined in the Handbook[31] apply to this acquisition transaction. EPCOR may apply for an ICM during the deferral period, however, the filing of its DSP for CollusLDC is a prerequisite to any ICM application.

[30] Letters from CollusLDC dated February 22, 2016 and March 1, 2017.
[31] Handbook, p. 17

5 CONCLUSION

The OEB has determined that the proposed transactions meet the “no harm” test and therefore the OEB approves these transactions.

The OEB also approves the Applicants’ related requests for:

- A 1% rate reduction to base residential distribution rates (exclusive of rate riders) relative to those established through CollusLDC’s 2018 rate setting process (EB-2017-0034).
- A deferral of the rate rebasing period of CollusLDC for five years from the date of closing of the proposed transactions.
- Approval to continue to track costs in the deferral and variance accounts currently approved for CollusLDC and to seek disposition of their balances at a future date.

6 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The Town of Collingwood is granted leave to acquire 50% of the issued and outstanding shares of Collingwood PowerStream Utility Service Corporation from Alectra Utilities Corporation.

2. EPCOR Collingwood Distribution Corporation is granted leave to purchase all of the issued and outstanding shares of Collingwood PowerStream Utility Service Corporation from the Town of Collingwood.

3. EPCOR Collingwood Distribution Corporation is granted approval to include a negative rate rider for residential distribution rates on the 2018 OEB approved rate schedules of Collus PowerStream Corporation to give effect to a 1% reduction relative to 2018 base residential distribution rate.

4. EPCOR Collingwood Distribution Corporation is granted approval to defer the rate rebasing of Collus PowerStream Corporation for a five year period following the date of closing of the share acquisition transactions listed as 1 and 2 above.

5. EPCOR Collingwood Distribution Corporation is granted approval to continue to track costs in the deferral and variance accounts currently approved by the OEB for Collus PowerStream Corporation and to seek disposition of their balances at a future date.

6. EPCOR shall file its Distribution System Plan for Collus PowerStream Corporation as a prerequisite to any Incremental Capital Module application.

7. The School Energy Coalition shall file with the OEB and forward to the Applicants its respective cost claim no later than 7 days from the date of issuance of this Decision and Order.

8. The Applicants shall file with the OEB and forward to the School Energy Coalition any objections to the claimed costs of the School Energy Coalition within 17 days from the date of issuance of this Decision and Order.

9. The School Energy Coalition shall file with the OEB and forward to the Applicants any responses to any objections for its cost claim within 24 days from the issuance of this Decision and Order.

10. The Applicants shall pay the OEB's costs of and incidental to, this proceeding immediately upon receipt of the OEB's invoice.

DATED at Toronto August 30, 2018

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary