EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

EB-2022-0028

OEB STAFF COMPENDIUM

Index

TAB 1

9.5 Current net metering thresholds of CollusLDC

The current net metering threshold of CollusLDC is 500 KW's. EPCOR has no plans to change this figure.

9.6 Final legal document to be used to implement the proposed transaction

The final legal documents to be used to implement the transaction are the Alectra Agreement (attached hereto as Schedule D) and the EPCOR Agreement (attached hereto at Schedule E). Copies of appropriate resolutions by parties approving the proposed transaction are attached in Schedule I.

10. Objective 1 – Protect consumers with respect to prices and the adequacy, reliability and quality of electricity service

10.1 Impact with respect to prices

As detailed below, 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. If EPCOR is successful in its stated strategy of aggressively participating in further consolidation of the Ontario LDC market, the economies and efficiencies as detailed below are expected to be increased.

As shown in Year 6 of Table 3, the forecasted cost structure of the proposed transactions will generate annual OM&A efficiencies of approximately $464,000 relative to the forecasted OM&A costs under the status quo[3]. This efficiency will translate directly into a lower revenue requirement and therefore rates for customers when it applies to rebase its rates following the five year rebasing deferral period.

[3] Status Quo forecast is the CollusLDC 2018 OM&A budget approved by its Board of Directors plus the cost of a CEO. The CEO position has been vacant since mid-2016.

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

Project		2023	2024	2025	2026	2027
1	**System Renewal**					
1.1	Miscallaneous Pole Replacement	$ 582,540	$ 582,540	$ 582,540	$ 582,540	$ 582,540
1.2	Miscallaneous Underground Rebuilds	$ 67,830	$ 67,830	$ 67,830	$ 67,830	$ 67,830
1.3	Pole Line Rebuilds 2023	$ 1,276,043				
	Olser Bluff Road	$551,887				
	Park Rd/East Trail	$362,086				
	Clarkson Crescent West Rear Lot	$362,070				
1.4	Pole Line Rebuilds 2024		$ 1,430,010			
	MS1 Feeder 3 (Sunnidale and Center line)		$653,300			
	MS2 Feeder 2 (Victoria and Huron)		$446,835			
	MS1 Feeder 5 (Arthur and Victoria)		$329,875			
1.5	Pole Line Rebuilds 2025			$ 1,267,058		
	MS5 Feeder 4 Substation Pole Replacements			$554,110		
	MS3 Feeder 2 (Pretty River to 280 Pretty River)			$215,393		
	MS2 - Feeder 1 (Cty Rd 42 to Christopher St)			$439,880		
1.6	Pole Line Rebuilds 2026				$ 1,518,467	
	Bruce St South Thornbury				$717,618	
	Arthur Street Pole Rehab				$457,792	
	Hurontario East North & South of Third				$343,057	
1.7	Pole Line Rebuild 2027					$ 1,453,284
	Mountain Road					$418,104
	Oak/Ferguson					$230,985
	Elizabeth					$327,575
	Campbell Street					$272,686
	Wellington St West					$203,934
1.8	Relay Replacments	$ 140,330	$ 127,900	$ 177,620		
	Total	$ 2,066,743	$ 2,208,280	$ 2,095,048	$ 2,168,837	$ 2,103,654
2	**System Service**					
2.1	Fault Line Indicators	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
2.2	SCADA Controlled Switches	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000
2.3	ArcPro and UN Migration	$ 508,602				
2.4	Stayner MS1 and MS2 Station Upgrades	$ 689,014	$ 723,750			
2.5	MS1 Thornbury Station Upgrade			$ 344,037		
2.6	MS2 Thornbury Station Upgrade				$ 344,037	
2.7	MS7 Collingwood Station Upgrade					$ 344,037
2.8	Customer Experience Enhancement	$ 40,000		$ 40,000		$ 40,000
2.9	WMS Implementation		$ 100,000	$ 149,682		
	Total	$ 1,372,616	$ 958,750	$ 668,719	$ 479,037	$ 519,037
3	**System Access**					
3.1	Customer Additions	$ 119,820	$ 128,207	$ 137,182	$ 146,784	$ 157,059
3.2	Road Relocations	$ 103,381	$ 105,449	$ 107,558	$ 109,709	$ 111,903
3.3	Meter Installations and Refurbishments	$ 377,878	$ 380,962	$ 384,108	$ 387,317	$ 390,589
	Total	$ 601,079	$ 614,618	$ 628,848	$ 643,810	$ 659,551
4	**General Plant**					
4.1	Fleet Vehicle	$ 210,000	$ 600,000	$ 380,000	$ 430,000	$ 500,000
4.2	IT Hardware Refresh	$ 20,400	$ 6,204	$ 15,764	$ 21,759	$ 54,770
4.3	OT Cyber Security	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
4.4	OT Servers Refresh		$ 80,000			
	Total	$ 255,400	$ 711,204	$ 420,764	$ 476,759	$ 579,770
	Total	**$ 4,295,838**	**$ 4,492,852**	**$ 3,813,379**	**$ 3,768,443**	**$ 3,862,012**

Material Investments 2023-2027

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

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

Distribution Ontario considered the uptake of cold climate heat pumps over the coming years? What challenges has this brought to EPCOR Electricity Distribution Ontario, and how has it affected planning during the DSP period?

EEDO Response:

EEDO has not considered the update of heat pumps in this DSP period, and has not experienced any impacts to date. If heat pumps were to become very widespread, loading challenges as discussed above with EV charging (electrification of energy) may also be experienced depending on the amount of electricity required to run the heat pumps.

d) How will future electrification affect the capital expenditure plan?

EEDO Response:

As explained above, electrification of energy will have an impact requiring increased investment in electrical infrastructure. The extent of that investment will depend on how optimally a utility is able to operate its system. It will be important to have a system model and distribution management tool to be able to assess, plan and operate this complex system. EEDO is ensuring it has these tools in place.

2-Staff-21

Number of Poles Being Replaced
Ref: Distribution System Plan, pages 39-40
Distribution System Plan, page 49
Distribution System Plan, pages 64, 69-70, 72, 75-76, 78, 81-82

Preamble:

EPCOR Electricity Distribution Ontario states that "[t]he pole replacement program together with the line overhead line replacement projects are expected to replace over 850 of the 1000 poles+ currently in poor or very poor condition during the 2023 – 2027 DSP period."

According to the METSCO Asset Condition Assessment, 891 wooden poles are currently in poor or very poor condition.

According to the EPCOR Electricity Distribution Ontario Business Cases, approximately 40 poles per year will be addressed through the System Renewal Miscellaneous Pole Replacement plan. In addition, EPCOR Electricity Distribution Ontario has developed the

System Renewal Pole Line Rebuilds/Extensions plan. The total number of poles being replaced is outlined in the table below as per the Business Cases.

Table 2-5: Number of Poles Being Replaced as per Business Case

Year	Miscellaneous Pole Replacement (Approximates)	Pole Line Rebuilds/Extensions
2023	40	38
2024	40	92
2025	40	63
2026	40	89
2027	40	66
Total	**200**	**348**

Question(s):

a) The METSCO Asset Condition Assessment states that 891 wooden poles are in poor or very poor condition but the stated plan is to "replace over 850 of the 1000 poles+ currently in poor or very poor condition." Please reconcile the total number of poles in poor or very poor condition.

EEDO Response:

This statement should read 891.

b) Please reconcile the number of poles being replaced in Table 2-5 with the stated plan of 850 poles.

EEDO Response:

This should read that the plan is to replace 548 of the 891 wooden poles currently in poor or very poor condition. The remaining poorly condition poles will be addressed in future DSP periods. EEDO does not have the resource to replace all 891 in this five year period, so it is focusing on the high priority areas as determined by its asset management and risk assessment process.

c) How were the total number of poles to be replaced in each year decided?

EEDO Response:

Pole line replacement projects are created around sections of identified poorly conditioned poles captured through resistograph testing. The poorly conditioned poles are layered into the GIS model of the system. This layer is used to identify segregated pole line replacement projects that can be planned and estimated. This is the most optimal way to plan pole replacements. These projects and the amount of poles replaced within a project are determined by resource estimating the labour required to complete the project.

d) Please provide the number of poles expected to be in poor or very poor condition by the end of the DSP period if all projects are completed.

EEDO Response:

EEDO will still have 343 poorly conditioned poles plus any fair poles (1630) that degrade into poor or very poor state. As this is conditioned based rather than end of life based, it is hard to predict the amount of poles requiring replacement at the end of this DSP period. About 24 poles fail the remaining strength test each year. Based on this, at least another 120 poles should drop to very poor condition.

2-Staff-22
Historical Expenditures – Pole Line Rebuild
Ref: Chapter 2 Appendix 2-AB
Distribution System Plan 2019-2023, page 110

Preamble:

In reference 1, the pole line rebuild program saw an increase of 200% between 2018 and 2019. In reference 2, EPCOR Electricity Distribution Ontario stated that this program is to address pole lines at end-of-life and it's determined through EPCOR Electricity Distribution Ontario's inspection process. EPCOR Electricity Distribution Ontario also budgeted $1.2 million for 2019 in pole line rebuild projects.

Question(s):

a) Please explain the variance between 2018 and 2019. Was the increase between 2018 to 2019 due to a new inspection process?

EEDO Response:

There was new resistograph inspection process introduced in 2017, and it took a couple years before impacting the capital plan.

b) Please provide the inspection process used in EPCOR Electricity Distribution Ontario's last DSP. Did EPCOR Electricity Distribution Ontario have an asset condition assessment for its poles? If so, please provide it.

d) The average unit cost per pole for the DSP period of 2023-2027 is $18,505 per pole. Please explain the higher unit cost forecast compared to previous periods.

EEDO Response:

Refer to 2-Staff 95a)

a) Has EPCOR Electricity Distribution Ontario changed its pole design standards for storm hardening?

EEDO Response:

EPCOR continues to use the USF Standards for pole design and would modify based on revisions to the standard.

2-Staff-96
Number of Poles Replaced
Ref: 2-Staff-21, Number of Poles Being Replaced

Preamble:

EPCOR Electricity Distribution Ontario states that it expects there to be approximately 463 poles left in poor or very poor condition by the end of the DSP period. This is significantly less than at the start of the DSP with 891 poles in poor or very poor condition.

Question(s):

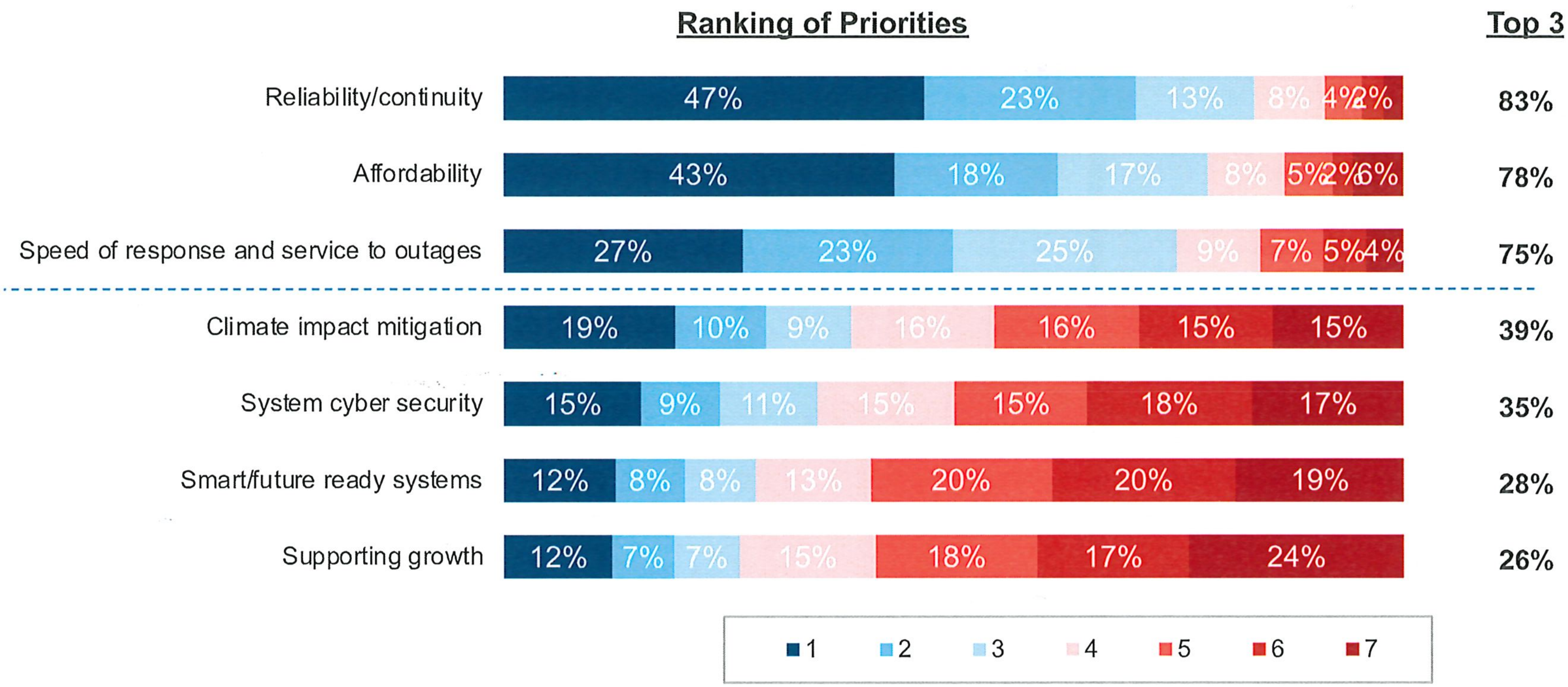
a) Is EPCOR Electricity Distribution Ontario's long-term goal to remove all poles in poor or very poor condition? At the pace of the existing program, there would be no poles in poor condition by the end of the next DSP period.

EEDO Response:

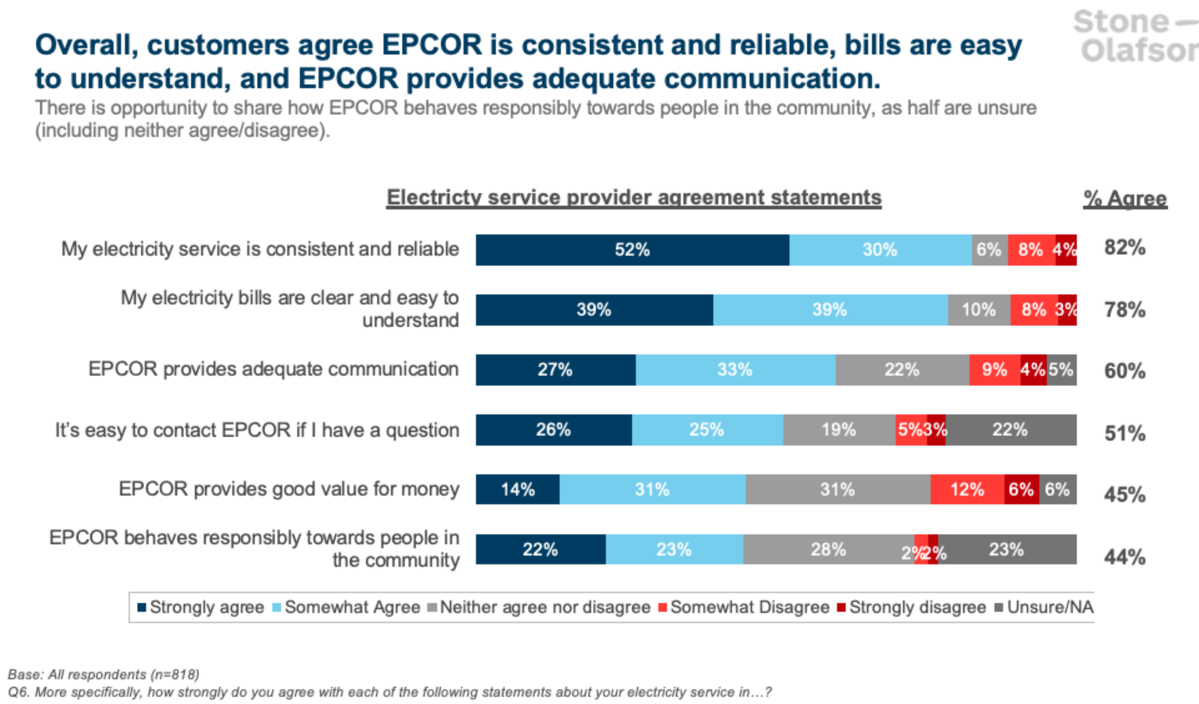
The long term goal is to address all of the poles that are in poor to very poor condition. Whether this is completed by the end of the next DSP period will depend on a number of variables such as cost of material, other deficiencies found in EPCOR's system that would require attention as a priority (older U/G cables start to fail and need replacing), substation issues, system access projects, storms, etc..

Reliability, affordability, and response to outages are the top priorities for customers.

Distantly followed by climate impact migration, system cyber security, smart/future ready systems, and supporting growth.



Base: Answered question (n=809)
Q8. Taking a step back, how would you rank each of the following in terms of importance where 1 is most important, and 7 is least important for electricity service planning in …(n=809)



When asked to rank priorities for EEDO, reliability, affordability and fast response times are the top three. These align with EEDO's investment priorities of renewing infrastructure, utilizing smart devices and enhancing grid technology that will help reduce outages, improve communication and make the system more efficient, as outlined in the DSP.

On an unaided basis, price and poor quality service are the main concerns customers have with their electricity service. Again multi-residential customers are slightly more likely to report both of these concerns.

Although, it's important to note that a higher proportion indicated no concerns.

Stone-Olafson

Electricity Concerns	Total	Residential (n=311)	Multi (n=177)	Commercial (n=8*)
Poor cost / price	32%	30%	32%	25%
Poor quality service	29%	26%	35%	25%
Increasing population / growth in the area / demand	5%	5%	7%	0%
Billing problems / issues / billing is not accurate	2%	2%	2%	0%
Other mentions	4%	5%	5%	0%
Nothing / no issues / concerns	38%	41%	33%	50%

Base: Answered open end (n=706)
Q5. What concerns, if any, do you have about electricity service in …?

**Caution: Small sample size*

2-Staff-97
Reliability
Ref: 2-Staff-25, Reliability

Preamble:

The table of defective equipment outages EPCOR Electricity Distribution Ontario provided does not include poles as a failure component.

Question(s):

a) Please confirm whether pole failure is included under defective equipment. If so, please confirm that no pole failures resulted in outages between 2017 to 2021.

EEDO Response:

Pole failure is currently not included under defective equipment. Pole failures are normally related to storm events or fallen trees.

b) Is EPCOR Electricity Distribution Ontario able to provide divide the tree contact cause code by "growth" and "fallen tree"? If so, please provide it.

EEDO Response:

This information is not available.

2-Staff-98
Stayner MS
Ref: 2-Staff-31, Stayner MS1 and M2

Preamble:

EPCOR Electricity Distribution Ontario provided the concurrent peak for the Stayner MS1 and MS2.

Question(s):

a) Please provide the top 5 concurrent peaks for Stayner MS1 and MS2 and the duration of each peak.

the GIS model of the system. This layer is used to identify segregated pole line replacement projects that can be planned and estimated. This is the most optimal way to plan pole replacements. These projects and the amount of poles replaced within a project are determined by resource estimating the labour required to complete the project.

d) Please provide the number of poles expected to be in poor or very poor condition by the end of the DSP period if all projects are completed.

EEDO Response:

EEDO will still have 343 poorly conditioned poles plus any fair poles (1630) that degrade into poor or very poor state. As this is conditioned based rather than end of life based, it is hard to predict the amount of poles requiring replacement at the end of this DSP period. About 24 poles fail the remaining strength test each year. Based on this, at least another 120 poles should drop to very poor condition.

2-Staff-22
Historical Expenditures – Pole Line Rebuild
Ref: Chapter 2 Appendix 2-AB
Distribution System Plan 2019-2023, page 110

Preamble:

In reference 1, the pole line rebuild program saw an increase of 200% between 2018 and 2019. In reference 2, EPCOR Electricity Distribution Ontario stated that this program is to address pole lines at end-of-life and it's determined through EPCOR Electricity Distribution Ontario's inspection process. EPCOR Electricity Distribution Ontario also budgeted $1.2 million for 2019 in pole line rebuild projects.

Question(s):

a) Please explain the variance between 2018 and 2019. Was the increase between 2018 to 2019 due to a new inspection process?

EEDO Response:

There was new resistograph inspection process introduced in 2017, and it took a couple years before impacting the capital plan.

b) Please provide the inspection process used in EPCOR Electricity Distribution Ontario's last DSP. Did EPCOR Electricity Distribution Ontario have an asset condition assessment for its poles? If so, please provide it.

EEDO Response:

EEDO was still responding to the condition assessment completed as part of its last filing in 2012 for 2013. This 2012 ACA was updated by its resistograph testing started in 2017. Please see the attached ACA from 2012 – 2-Staff-22 Attachment 1.

c) Please explain the variance between EPCOR Electricity Distribution Ontario's budgeted $1.2 million in pole line rebuilds but actuals of $1.9 million.

EEDO Response:

The variance is due to the additional costs related to of catch up on pole line rebuilds not completed in 2018.

Between 2020 and 2022 EPCOR Electricity Distribution Ontario planned to spend $5.8 million on pole line rebuilds but EPCOR Electricity Distribution Ontario's actuals were only $4.1 million, an underspend of 30%.

d) Please explain the underspending between 2020 and 2022.

EEDO Response:

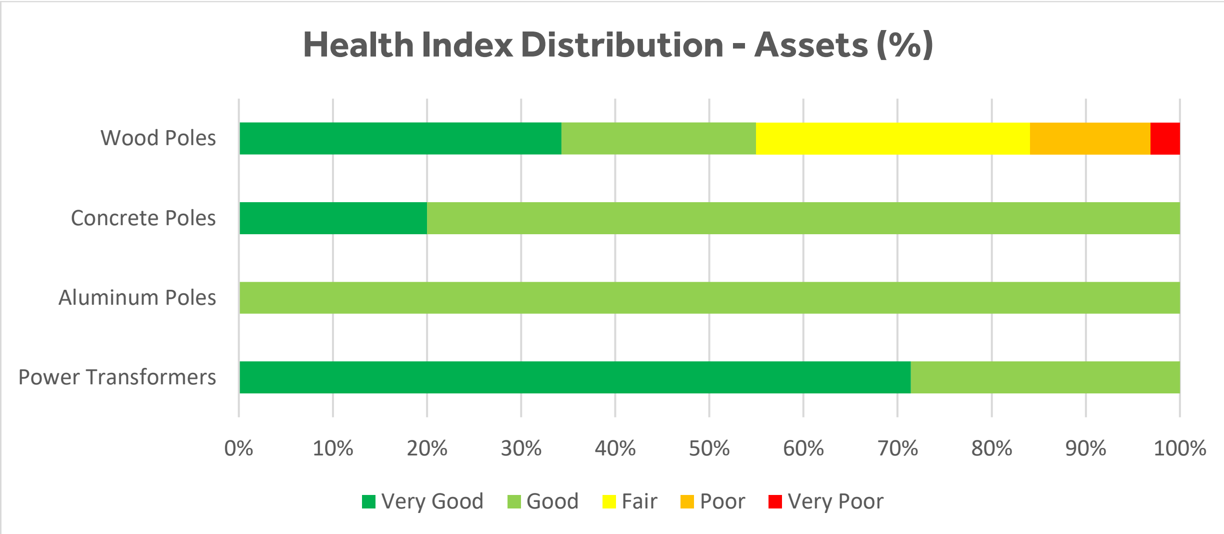
The reason for the under spend is a factor of trying to accomplish more than the utility's resources (both internal and external) could reasonably accomplish. The utility would have had to add additional internal resources or external contractors in order to complete the planned program.

e) Please explain how there can be confidence in the 2023 estimate for the pole line rebuild program.

EEDO Response:

EEDO has introduced a capital planning governance program that incorporates industry best practices around project management. As part of this program, EEDO has aligned what its resources can reasonably accomplish with the risk assessment of pole line conditions. EEDO expects that it can facilitate approximately $2M/year in pole line rebuilds and that this is enough to address the high risk areas to maintain a safe and reliable system.

Figure 0-1: Distribution & Station Assets Health Index Results



As Figure 0-1 indicates, most EPCOR Ontario's assets fall within Very Good or Good condition. There are, however, a significant number of wood poles found to be in Poor or Very Poor condition which should be assessed for replacement or refurbishment.

Table 0-2: Asset Condition Assessment Overall Results

Asset Class	Population	Health Index Distribution (%)					Average DAI		Average Health Index
		Very Good	Good	Fair	Poor	Very Poor			
Distribution Assets									
Wood Poles	5597	34%	21%	29%	13%	3%	Year of Installation	85%	68%
							Pole Treatment	62%	
							Remaining Pole Strength	20%	
							Visual Inspection	60%	
Concrete Poles	20	20%	80%	0%	0%	0%	Year of Installation	25%	78%
							Pole Treatment	0%	
							Remaining Pole Strength	0%	
							Visual Inspection	5%	
Aluminum Poles	2	0%	100%	0%	0%	0%	Year of Installation	0%	75%
							Pole Treatment	0%	
							Remaining Pole Strength	0%	
							Visual Inspection	0%	
Station Assets									
Power Transformers	14	71%	29%	0%	0%	0%	All Parameters	100%	83%

See below for a list of projects from the 2013 to 2017 plan that were not completed by the end of 2017, these projects were all completed by the end of 2018.

#	Project Name	Project Budget	Project Spend through 2017
1	Leslie Drive Pole Trans Replacement	168,000	89,717
2	Maple Street pole Trans Replacement	42,000	25,670
3	Heritage Drive 4.16kV Pole Line Rebuild	264,500	59,731
4	Walnut Street Trail 44kV/4 Poles	92,000	16,314
5	Stayner St MS2 to North Street - Stayner	210,000	80,623
6	MS2 - Collingwood U/G Feeder Egress	120,000	27,531

2-Staff-18
Historical Expenditures
Ref: Chapter 2 Appendix 2-AB

Preamble:

The average actual capital expenditure between 2013 to 2017 was $2 million. The average actual capital expenditure between 2018 to 2022 was $3.4 million, a 70% increase.

Question(s):

a) Please explain the drivers for the increase in average capital expenditures between 2013-2017 and 2018-2022.

EEDO Response:

The main drivers are an increase in spending on pole line rebuilds ($769k) and pole replacements (148k), customer demanded work/road authority ($194k), and vehicles ($125k).

In 2013 and 2014 the utility did not have the internal resources to meet the capital work demands. Operational resources were increased in 2015 by adding 3 additional linescrew and in 2019 by 1 inspector/locator FTE which enabled the utility to increase the amount of capital work each year.

b) A large portion of the increase in capital spending over 2018-2022 is in system renewal. Please confirm if this is mostly due to pole replacement and line rebuilds. If so, please provide a table of the total number of poles replaced each year for each of the pole-related programs.

EEDO Response:

System Renewal spending over 2018-2022 has primarily been to replace poorly conditioned pole lines.

EEDO was unable to find the data to disaggregate the number of poles for each of the pole-related programs by year.

EEDO has provided the total number of poles installed across all programs per year below:

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Poles Installed	89	108	107	186	141	108	130	134	162	135

2-Staff-19

MAADs Capital Plan
Ref: Chapter 2 Appendix 2-AB
EB-2018-0025, Distribution System Plan 2019-2023, page 12
EB-2017-0373 & EB-2017-0374, page 31

Preamble:

EPCOR Electricity Distribution Ontario provided capital expenditure plan from 2019 to 2024 as part of the MAADs application submitted in 2017 (EB-2017-0373 & EB-2017-0374). EPCOR Electricity Distribution Ontario submitted a DSP in 2018 (EB-2018-0025) for the 2019 to 2023 period.

Question(s):

a) Please explain the variance between the planned capital investment summary in the 2019-2023 DSP, the MAADs application, and the 2023-2027 DSP for the period of 2019 to 2023.

EEDO Response:

The primary reason for the variance between the MAAD application and the 2019-2023 DSP relates to the planned investment into system renewal projects. This was mainly in pole line or underground feeders that were deemed to be in poor or very poor condition. This project risk assessment was not complete at the time of the MAAD application, but was completed

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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**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

2-Staff-95
Cost of Pole Replacement
Ref: 2-Staff-18, Historical Expenditures
2-Staff-21, Number of Poles Being Replaced

Preamble:

EPCOR Electricity Distribution Ontario provided the number of poles replaced under system renewal in reference 1. Comparing the number of poles replaced and the total program budget in Chapter 2 Appendix 2-AA shows that the average cost to replace a pole was around $7,400 between 2013 to 2018. The average cost to replace a pole between 2019 to 2022 was $14,100.

Question(s):

a) Please explain the driver of the unit cost almost doubling.

EEDO Response:

Many of the poles in our 2023 plan are rear lot construction. This is driving our labour costs higher due to the extra person hours it will take to access back yards, climb poles to complete work and complete restoration of homeowners properties compared to being able to access with bucket trucks. We will being seeing higher contractor costs associated 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.

b) In reference 2, EPCOR Electricity Distribution Ontario plans to replace on average 110 poles/year, whereas in the past five years EPCOR Electricity Distribution Ontario replaced on average 134 poles/year. Please explain the lower planned replacements of poles.

EEDO Response:

Refer to 2-Staff 95a)

c) The average unit cost per pole in 2023 is $16,900 per pole. Please explain the higher unit cost forecast.

EEDO Response:

Refer to 2-Staff 95a)

d) The average unit cost per pole for the DSP period of 2023-2027 is $18,505 per pole. Please explain the higher unit cost forecast compared to previous periods.

EEDO Response:

Refer to 2-Staff 95a)

a) Has EPCOR Electricity Distribution Ontario changed its pole design standards for storm hardening?

EEDO Response:

EPCOR continues to use the USF Standards for pole design and would modify based on revisions to the standard.

2-Staff-96
Number of Poles Replaced
Ref: 2-Staff-21, Number of Poles Being Replaced

Preamble:

EPCOR Electricity Distribution Ontario states that it expects there to be approximately 463 poles left in poor or very poor condition by the end of the DSP period. This is significantly less than at the start of the DSP with 891 poles in poor or very poor condition.

Question(s):

a) Is EPCOR Electricity Distribution Ontario's long-term goal to remove all poles in poor or very poor condition? At the pace of the existing program, there would be no poles in poor condition by the end of the next DSP period.

EEDO Response:

The long term goal is to address all of the poles that are in poor to very poor condition. Whether this is completed by the end of the next DSP period will depend on a number of variables such as cost of material, other deficiencies found in EPCOR's system that would require attention as a priority (older U/G cables start to fail and need replacing), substation issues, system access projects, storms, etc..

Preamble:

EPCOR Electricity Distribution Ontario uses Esri's ArcMap software for utility asset database recording and stated that it needs to upgrade to the next generation of the ArcMap software. EPCOR Electricity Distribution Ontario only considered updating the software or not.

Question(s):

Did EPCOR Electricity Distribution Ontario consider using other vendors for GIS software? If not, why not?

EEDO Response:

No, as there are no suitable vendors available. We are using the main industry standard software. We have been using the same vendor since 1995, our systems are setup to work with their software. As well, we have the in-house expertise to trouble shoot and maintain the server technology.

EPCOR Electricity Distribution Ontario stated that software updates will cease in 2024 but the support for ArcMAP won't cease until 2026. What software updates are typically provided? What is the risk of one year less of software upgrades?

EEDO Response:

The vendor will stop updating and supporting the software, meaning the software becomes vulnerable to security and performance issues as time passes. As EEDO is already 4 years behind, the risk of an event continues to increase.

2-Staff-31
Stayner MS1 and M2
Ref: Distribution System Plan – System Service – Stayner MS1 and MS2 Substation Upgrades, page 97
Distribution System Plan – Station Loading, page 41

Preamble:

In reference 2, it shows Stayner MS1 has a peak load of 2.9MVA and MS2 has a peak load of 4.9MVA, while the average load is 1.5MVA for both stations.

Question(s):

a) Has EPCOR Electricity Distribution Ontario purchased the two new 7.5MVA transformers? What will EPCOR Electricity Distribution Ontario do with the existing 5MVA transformers?

EEDO Response:

EPCOR has drafted the RFP for these two transformers, but hasn't committed to a purchase yet until the end of this proceeding. EPCOR will look to put the existing 5MVA transformers back into inventory as spares if possible, or look to salvage for any value.

b) Please provide the number of hours or days the peak lasts on Stayner MS1 and MS2.

EEDO Response:

MS1 peaked on February 13 2021 @ 18:05 with a value of 2806.222 Kw. It was at 95% of peak (2665.911 kW) from 16:46 to 19:05.

MS2 peaked on November 14 2021 @ 17:10 with a peak value of 4761.501 kW. It was at 95% of peak (4523.426 kW) from 16:51 to 18:15.

c) Please confirm if the peaks provided are concurrent peaks or the peak on each station. If it is the peak on each station, please provide the concurrent peak for the Stayner service area.

EEDO Response:

The above was the peak at each station.

The concurrent peak for the Stayner service area was on June 27 2021 @ 18:00 with a total value of 5957.561 kW.

MS1 Concurrent Value: 2207.875 kW

MS2 Concurrent Value: 3749.686 kW

d) In the worst-case scenario, one station (7.5MVA) needs to supply all of the peak load (7.8MVA). Please explain why EPCOR Electricity Distribution Ontario chose to replace the existing transformers with a 7.5MVA transformer knowing the peak load.

EEDO Response:

The number of hours where coincidental peak would occur with one transformer out of service didn't warrant designing a larger transformer.

e) Does EPCOR Electricity Distribution Ontario have any standards on how long a transformer can be temporarily overloaded? If not, why?

EEDO Response:

Please refer to page 41 of the DSP, Station Capacity. EEDO targets to not exceed 75% capacity of the normal rating of the station transformer. It is hard to have a standard on how long a transformer can be temporarily overloaded because every transformer's condition will decline differently depending on the life time of loading conditions, not just due to one event. EEDO would aim to keep any overloading condition to a minimum, and monitor the transformers condition through substation maintenance programs.

f) Is the forecasted load growth on the edge of the Stayner service territory? If so, are there neighboring 4.16kV feeders from Hydro One that EPCOR Electricity Distribution Ontario could use to supply the load growth?

EEDO Response:

There are not existing Hydro One 4.16kV lines that could service this growth area. Hydro One would have to extend their current feeders into our service territory.

g) Has forecasted load growth accounted for the rise of electric vehicles, cold climate heat pumps, and renewable energy distribution?

EEDO Response:

No, EEDO does not have reliable data assumptions on these items to include in its load forecast. Historical load growth continues to be the best indicator which would include this load growth to date.

h) Did EPCOR Electricity Distribution Ontario consider CDM/ non-wire solutions that may defer or avoid the need to upgrade one or both Stayner MS1 and MS2 Substations in 2023 and 2024 to meet anticipated load growth?

EEDO Response:

EPCOR did not consider whether a non-wires solution could meet the growing demand. It is possible that as non-wires alternatives become wide spread that this could defer any further increases or new facilities being required.

2-Staff-32
Vegetation Management
Ref: Distribution System Plan, page 51

b) A large portion of the increase in capital spending over 2018-2022 is in system renewal. Please confirm if this is mostly due to pole replacement and line rebuilds. If so, please provide a table of the total number of poles replaced each year for each of the pole-related programs.

EEDO Response:

System Renewal spending over 2018-2022 has primarily been to replace poorly conditioned pole lines.

EEDO was unable to find the data to disaggregate the number of poles for each of the pole-related programs by year.

EEDO has provided the total number of poles installed across all programs per year below:

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Poles Installed	89	108	107	186	141	108	130	134	162	135

2-Staff-19

MAADs Capital Plan
Ref: Chapter 2 Appendix 2-AB
EB-2018-0025, Distribution System Plan 2019-2023, page 12
EB-2017-0373 & EB-2017-0374, page 31

Preamble:

EPCOR Electricity Distribution Ontario provided capital expenditure plan from 2019 to 2024 as part of the MAADs application submitted in 2017 (EB-2017-0373 & EB-2017-0374). EPCOR Electricity Distribution Ontario submitted a DSP in 2018 (EB-2018-0025) for the 2019 to 2023 period.

Question(s):

a) Please explain the variance between the planned capital investment summary in the 2019-2023 DSP, the MAADs application, and the 2023-2027 DSP for the period of 2019 to 2023.

EEDO Response:

The primary reason for the variance between the MAAD application and the 2019-2023 DSP relates to the planned investment into system renewal projects. This was mainly in pole line or underground feeders that were deemed to be in poor or very poor condition. This project risk assessment was not complete at the time of the MAAD application, but was completed during the development of the 2019-2023 DSP resulting in an increase in planned system renewal investment.

The primary reason for the variance between the planned spend in 2023 from the 2023-2027 DSP and that of the 2019-2023 DSP is that the system renewal spend is reduced to what is deemed achievable by EEDO considering the condition of the pole lines, and the system service spend is increased significantly to reflect required investment in municipal stations and in underlying technology upgrades such as the GIS upgrade.

2-Staff-20
Electrification and EV Accommodation
Ref: Distribution System Plan, page 7

Preamble:

EPCOR Electricity Distribution Ontario has "developed a plan to continue to upgrade, modify and keep secure grid technology solutions to maintain pace with growing distributed energy resources" such as electric vehicle (EV) integration and distributed renewable energy.

Question(s):

a) Please provide the plan referred to on page 7 of the DSP.

EEDO Response:

The plan referred to is the DSP itself. Specifically and by way of an example of this prepare for EV adoption, EEDO plans to upgrade its underlying GIS platform which supports its electrically connected grid model. This model underpins EEDO's SmartMap distribution management system. AMI data is integrated into EEDO's SmartMap permitting for near real time load flow analysis. The use of SmartMap along with AMI data can be utilised to quickly detect where EV charging may be occurring on the system where a high capacity charger may have been installed by a homeowner without the utility's knowledge. This system intelligence may permit the utility to identify distribution transformer overloading conditions prior to a failure occurring on the system.

Similarly, the integration of distributed energy resources such as rooftop solar PV or household battery banks, will result in a changing load flow. It will be critical for EEDO to have an electrically connected model and DMS in order to be able to assess the grid impacts and optimize the system in order to enable DER integration and maintain safety and reliability.

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

First year of Forecast Period: *2019*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2014			2015			2016			2017			2018			2019	2020	2021	2022	2023
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		421	--		561	--	319	259	-18.8%	303	421	38.9%	581	414	-28.7%	312	517	354	361	391
System Renewal		482	--		623	--	1,558	1,116	-28.4%	2,116	2,118	0.1%	1,895	1,306	-31.1%	2,118	2,450	2,374	2,881	2,865
System Service		512	--		395	--	1,015	697	-31.3%	51	36	-29.4%	51	3	-94.1%	300	75	77	79	81
General Plant		387	--		131	--	621	508	-18.2%	626	459	-26.7%	652	139	-78.7%	569	658	586	264	568
TOTAL EXPENDITURE	2,521	1,802	-28.5%	3,389	1,710	-49.5%	3,513	2,580	-26.6%	3,096	3,034	-2.0%	3,179	1,862	-41.4%	3,299	3,700	3,391	3,585	3,905
System O&M		$ 2,169	--		$ 2,389	--	$ 2,298	$ 2,482	8.0%	$ 2,517	$ 2,190	-13.0%	$ 2,651	$ 2,310	-12.9%	$ 2,645	$ 2,711	$ 2,856	$ 2,848	$ 2,905

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
System Renewal spending increase in forecast period reflects increase in resources directed to address plant in very poor and poor condition. System Service spending high in 2019 in order to repalce legacy SCADA system.
Notes on year over year Plan vs. Actual variances for Total Expenditures
Overall spending reduced in 2016 and 2018 due to labour resource issues.
Notes on Plan vs. Actual variance trends for individual expenditure categories

Table 42 – Capital Expenditure Summary

5.4.1 Capital Expenditure Summary

Appendix 2-AB

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

First year of Forecast Period: *2023*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2018			2019			2020			2021			2022			2023	2024	2025	2026	2027
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	1,039,693	1,418,795	36.5%	779,089	1,168,871	50.0%	993,236	1,739,778	75.2%	1,008,318	1,543,583	53.1%	2,279,019	2,279,019	0.0%	1,331,751	1,361,747	1,393,275	1,426,425	1,461,301
System Renewal	1,895,340	1,306,416	-31.1%	2,117,880	2,376,731	12.2%	2,449,813	2,040,826	-16.7%	2,594,023	2,750,666	6.0%	2,025,599	2,106,671	4.0%	2,066,743	2,208,280	2,095,048	2,168,837	2,103,654
System Service	51,087	2,956	-94.2%	300,000	305,635	1.9%	75,000	8,085	-89.2%	101,875	71,150	-30.2%	103,979	103,979	0.0%	1,372,616	935,000	668,719	479,037	519,037
General Plant	651,930	138,927	-78.7%	569,210	1,094,796	92.3%	657,757	574,179	-12.7%	693,180	99,845	-85.6%	440,548	940,548	113.5%	255,400	711,204	420,764	476,759	579,770
TOTAL EXPENDITURE	3,638,050	2,867,094	-21.2%	3,766,179	4,946,033	31.3%	4,175,806	4,362,868	4.5%	4,397,396	4,465,244	1.5%	4,849,145	5,430,217	12.0%	5,026,510	5,216,231	4,577,806	4,551,058	4,663,762
Capital Contributions	- 458,423	-1,004,456	119.1%	- 467,133	- 811,666	73.8%	- 476,009	-1,086,111	128.2%	- 654,494	- 690,144	5.4%	-1,391,830	-1,391,830	0.0%	- 730,672	- 747,130	- 764,428	- 782,615	- 801,750
Net Capital Expenditures	3,179,627	1,862,638	-41.4%	3,299,046	4,134,367	25.3%	3,699,797	3,276,757	-11.4%	3,742,902	3,775,100	0.9%	3,457,315	4,038,387	16.8%	4,295,838	4,469,102	3,813,379	3,768,443	3,862,012
System O&M	$ -	$ 184,538	--	$ -	-$ 75,605	--	$ -	-$ 26,330	--	$ -	-$ 118,065	--	$ -	$ -	--	$ -	$ -	$ -	$ -	$ -

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

The increase in system access spend as compared to historical budgets/actuals is a result of the AMI meters reaching OEB defined OEL requiring refurbishment or life extension. The increase in system service spend is the forecast vs historic budgets reflects investments in grid modernization of aging municiple stations, and to keep pace with customer innovations and expectations of greater customer participation. General Plant spend reflects fleet vehicle inflationary cost increases.

Notes on year over year Plan vs. Actual variances for Total Expenditures

EEDO was underspent in 2018 to plan as a result of going through the transition to EEDO from Collus.

Notes on Plan vs. Actual variance trends for individual expenditure categories

General plant costs varied from plan based on the timing of delivery of procured fleet vehicles. System access plan vs actual varied based on developer projects in year.

Capital Expenditure Summary 2023-2027

5.4.2 Previous 5 year Capital Variance Explanation

System Access

EEDO's System Access investments are driven by others. EEDO is obligated to connect new load and new renewable generation. EEDO uses an economic evaluation methodology prescribed in the DSC to determine the level, if any, of capital contributions for each project with such levels incorporated into the annual capital budget. The scheduling of investments needs is usually coordinated to meet the needs of third parties.

EEDO is required to install metering equipment and provide access to poles for 3rd party attachments as per its mandated service obligation. EEDO is also required to respond to the road authorities by obligations under the *Public Service Works on Highways Act.* The Act prescribes a formula for the apportionment of costs that allows for the road authority to contribute 50% of the "cost of labour and labour saving devices" towards the relocation costs. This formula was used to apportion costs for road authority projects requiring the relocation of EEDO plant.

The level of system access expenditures in each of 2018 to 2022 historical years has varied between $232k and $566k net of contributions. Spend fluctuated between the three area of new meters, customer initiated projects and road relocations. Variance to budget is impacted by the timing and commitment of customer initiated work and how accurate the budget estimate is to the economic evaluation closer to completing the work. Unplanned customer initiated work or time shifted customer initiated often impacts the resourcing available for system renewal projects.

EPCOR Ontario's Current Health Index Maturity and Continuous Improvement

Overall, EPCOR Ontario's asset data collection practices are sufficiently robust to enable calculation of the recommended ACA that is consistent with industry best practices for the asset classes in this study. EPCOR Ontario would benefit from enhanced documentation of its asset inspection and maintenance practices using mobile workforce tools connected to a Centralized Maintenance Management System.

For the wood poles analyzed, there are some opportunities to improve the data availability and data quality. EPCOR Ontario aimed at conducting resistograph test on all distribution wood poles that are older than 20 years of age. Currently, EPCOR Ontario houses resistograph test data for just one-third of the total in-service wood pole population under consideration. It was identified that majority of the wood poles beyond 20 years of age were not tested, and some wood poles tested were younger than 20 years of age. Over the following years, EPCOR Ontario can look to consistently produce resistograph test results for wood poles older than 20 years of age.

Additionally, about one-fifth of the wood poles under consideration had both installation and manufacture dates unknown. To calculate pole service age, these data deficiencies were supplemented by applying a predictive analytics algorithm to predict pole manufacture years. Several inputs were used as main predictors to run this algorithm such as pole height, pole class, pole type, pole coordinates, etc. Few of these predictor fields were also missing allowing for subsequent data assumptions and the pole ages were calculated. It is recommended that EPCOR Ontario look to fill in these data gaps in future as old, archived poles are being replaced by new poles in-field.

The power transformers included in this assessment had a very high data availability index, and hence, a full analysis could be done without any assumptions. Power transformer data is currently collected via paper forms, which should be automatically digitized in the future.

In providing these recommendations, METSCO is cognizant of the fact that regulated utilities are facing cost constraints across numerous facets of their operations, while contending with the effects of aging infrastructure, changing climate, evolving customer needs, and many other priorities. As such, an adoption of any incremental enhancement to the existing asset data collection practices must be grounded in management's assessment of the incremental value of such enhancements, relative to the opportunity cost of advancements elsewhere in the utility's operations. METSCO makes this observation to highlight its position that the sole fact of a gap between a utility's current process state and the industry best practices need not necessarily indicate that an action to remedy that gap is required in short order.

Pole Replacement Unit Costs (OEB Staff Calculations)

	2013	2014	2015	2016	2017	2018
Pole replacement program	$311,542	$222,714	$234,602	$335,339	$465,401	$370,665
Pole line rebuild	$302,620	$489,287	$411,970	$533,955	$1,100,367	$624,202
Total pole cost	$614,162	$712,001	$646,572	$869,294	$1,565,768	$994,867
Number of poles replaced	89	108	107	186	141	108
Annual Average	$6,901	$6,593	$6,043	$4,674	$11,105	$9,212
Average						$7,421

	2019	2020	2021	2022
Pole replacement program	$196,641	$587,011	$595,826	$558,491
Pole line rebuild	$1,941,992	$1,285,638	$1,513,561	$1,204,953
Total pole cost	$2,138,633	$1,872,649	$2,109,387	$1,763,444
Number of poles replaced	130	134	162	135
Annual Average	$16,451	$13,975	$13,021	$13,063
Average				$14,127

	2023	2024	2025	2026	2027
Pole replacement program	582,540	582,540	582,540	582,540	582,540
Pole line rebuild	1,276,043	1,430,010	1,267,058	1,518,467	1,453,284
Total pole cost	1,858,583	2,012,550	1,849,598	2,101,007	2,035,824
Number of poles replaced	78	132	103	129	106
Annual Average	$23,828	$15,247	$17,957	$16,287	$19,206
Average (2023-2027)					$18,505
Average (2024-2027)					$17,174

TAB 2

Appendix 2-K
Employee Costs

	A	B	C	D	E	F	G	H	I	J	K	L	M
12		**Last Rebasing Year (2013 OEB Approved)**	**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**
13	**Number of Employees (FTEs including Part-Time)[1]**												
14	Management (including executive)	2.8	3.8	4.1	4.4	4.7	5.3	4.7	5.2	4.3	3.5	2.9	2.6
15	Non-Management (union and non-union)	20.2	18.6	18.9	19.4	20.7	22.1	24.0	23.3	25.1	24.7	25.8	25.6
16	Total	22.9	22.4	23.0	23.8	25.4	27.5	28.7	28.5	29.4	28.2	28.7	28.2
17	**Total Salary and Wages including ovetime and incentive pay**												
18	Management (including executive)	$ 429,991	$ 617,409	$ 643,069	$ 657,198	$ 812,126	$ 738,532	$ 771,857	$ 712,282	$ 631,168	$ 538,935	$ 482,857	$ 450,612
19	Non-Management (union and non-union)	$ 1,605,613	$ 1,474,242	$ 1,653,959	$ 1,790,226	$ 1,977,502	$ 1,940,020	$ 2,093,401	$ 2,177,392	$ 2,399,134	$ 2,417,262	$ 2,556,255	$ 2,634,374
20	Total	$ 2,035,604	$ 2,091,651	$ 2,297,028	$ 2,447,424	$ 2,789,628	$ 2,678,552	$ 2,865,258	$ 2,889,674	$ 3,030,301	$ 2,956,197	$ 3,039,112	$ 3,084,986
21	**Total Benefits (Current + Accrued)**												
22	Management (including executive)	$ 90,208	$ 174,531	$ 158,230	$ 160,914	$ 194,431	$ 210,576	$ 213,589	$ 203,540	$ 178,620	$ 159,599	$ 136,043	$ 127,291
23	Non-Management (union and non-union)	$ 333,867	$ 416,744	$ 406,965	$ 438,334	$ 473,434	$ 469,909	$ 492,747	$ 528,474	$ 592,999	$ 630,040	$ 641,591	$ 666,957
24	Total	$ 424,075	$ 591,275	$ 565,195	$ 599,248	$ 667,865	$ 680,485	$ 706,336	$ 732,014	$ 771,619	$ 789,639	$ 777,634	$ 794,248
25	**Total Compensation (Salary, Wages, & Benefits)**												
26	Management (including executive)	$ 520,199	$ 791,940	$ 801,299	$ 818,112	$ 1,006,557	$ 949,108	$ 985,446	$ 915,822	$ 809,788	$ 698,534	$ 618,900	$ 577,903
27	Non-Management (union and non-union)	$ 1,939,480	$ 1,890,986	$ 2,060,924	$ 2,228,560	$ 2,450,936	$ 2,409,929	$ 2,586,148	$ 2,705,866	$ 2,992,133	$ 3,047,302	$ 3,197,846	$ 3,301,331
28	Total	$ 2,459,679	$ 2,682,926	$ 2,862,223	$ 3,046,672	$ 3,457,493	$ 3,359,037	$ 3,571,594	$ 3,621,688	$ 3,801,920	$ 3,745,836	$ 3,816,746	$ 3,879,234
29	**Total Compensation Breakdown (Capital, OM&A)**												
30	OM&A	$ 2,253,759	$ 2,323,502	$ 2,528,008	$ 2,240,867	$ 2,608,256	$ 2,141,106	$ 2,439,249	$ 2,518,630	$ 2,817,715	$ 2,338,704	$ 2,483,929	$ 2,500,567
31	Capital	$ 205,920	$ 359,424	$ 334,214	$ 805,804	$ 849,236	$ 1,217,931	$ 1,132,345	$ 1,103,058	$ 984,205	$ 1,407,132	$ 1,332,817	$ 1,378,667
32	Total	$ 2,459,679	$ 2,682,926	$ 2,862,223	$ 3,046,672	$ 3,457,493	$ 3,359,037	$ 3,571,594	$ 3,621,688	$ 3,801,920	$ 3,745,836	$ 3,816,746	$ 3,879,234

Note:

1. If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

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.

b) Were there any savings as a result of EPCOR affiliates now providing services that were previously provided by other affiliates?

EEDO Response:

In 2019, EPCOR was integrating the EEDO operations to determine what services were required to be provided and the most efficient way to provide these services. Additional cost savings would following subsequent years, but a few items noted and implemented in 2019 included:

1. EEDO was able to get EDTI to provide Systems Controls service at lower costs than Alectra was charging EEDO, and EDTI provided more services as well.
2. EEDO did not fill the vacant CEO position, and the Management Oversight services provided by EOUI were much less costly than hiring a CEO.
3. EEDO was able to move the HR, Manager position to a shared service with the other EPCOR Ontario-based operations and reduce the direct HR cost to EEDO.
4. EEDO was able to take advantage of the shared service model in Ontario and receive required services that were missing (primarily HSE in 2019) without having to hire full FTEs.

4-SEC-34

[Ex.4, Tables 4.4.2-1 & 15] Shared Services - The table below combines information from Tables 4.4.2-1 and 4.4.2-15:

a) Please complete the requested information, approved amounts for 2013 and actuals for 2014 to 2018.

EEDO Response:

$000	2013 appr.	2013 actual	2014 actual	2015 actual	2016 actual	2017 actual	2018 actual	2019 actual	2020 actual	2021 actual	2022 bridge	2023 test year
Collus PowerStream Solutions	1,071	975	1,144	1,068	694	-	-					
Service Fee	132	132	132	-	-	-	-					
Town of Collingwood	59	22	5	8	19	39	17					
Collingwood PUC	367	310	287	276	238	216	180					
Alectra	-	182	239	160	221	181	115					
Affiliate Shared Services								365	557	511	758	790
Corporate Shared Services							186	740	682	660	792	875
Total	**1,629**	**1,621**	**1,807**	**1,512**	**1,172**	**436**	**498**	**1,105**	**1,239**	**1,171**	**1,550**	**1,665**

The Alectra row was added as Alectra provided certain services to EEDO from 2013A to 2018A, in addition to the other rows included in the original IR question. Affiliate Shared Services did not begin until the 2019A year.

b) As noted in the next question, $216k of the payment to the Collingwood PUC was moved from OM&A to rate base. Please explain any other material changes which occurred in the Shared Services payment between 2013 and 2018.

EEDO Response:

Starting in 2016, Collus Powerstream solutions ceased providing shared services. See page 10 in Exhibit 4 for further information.

Alectra provided CDM services until 2017, after which CDM costs were shifted as a result of the conservation first framework (CFF). CDM costs administered by Alectra were paid via an IESO approved budget (funded through the global adjustment)

Alectra ceased providing various services when EEDO was acquired by EPCOR in 2018.

4-SEC-35

[Ex.4, pp. 17 & 89] The application states on page 17 that 'EEDO's lease with the Town of Collingwood has been included as a capital lease and amortization of the Lease Asset is included in USofA account 6045'. Page 89 states, 'The 2013 Actual Collingwood Public Utilities Service Board includes $216,000 for building 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.':

a) Please indicate on which Tab in Appendix 2 one can find reference to USofA 6045.
b) Please indicate in which USoA in Appendix 2-BA one can find the lease with the Town of Collingwood.

EEDO Response

a) The depreciation found in USofA 6045 can be referenced indirectly on Appendix 2-BA through the Property Under Finance Lease row (USoA 2005) in the additions to Accumulated Depreciation.

b) The lease with the Town of Collingwood is included in USoA 2005 starting in 2019.

4-SEC-36

[Ex.4, p. 60] Please explain exactly what the function is of each of the following entities: EWSI, EDTI, EOOMI, EUI and EOUI.

EEDO Response:

EOOMI provides shared services to all of EPCOR's operations in Ontario. Prior to 2022, EOUI provided these shared services.

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

The Manager of Operations Network & Security may be moved under Engineering.

c) Has the move of the Operations Network & Security Manager position to an affiliate company as noted would occur in 2022 in Exhibit 4 been completed? In Figure 1.3-2, there is a role labeled as “Manager, Ops Network”. Please confirm if this is the role noted in Exhibit 4.

EEDO Response:

EEDO confirms that the Operations Network & Security Manager move has been completed in 2022. EEDO confirms that the Manager, Ops Network refers to the same role.

d) EPCOR Electricity Distribution Ontario provided the FTE figures from 2013 to 2023 in Appendix 2-K and in Table 4.4.1-3 on page 44 of Exhibit 4. Please clarify if the FTE data in these two tables include any shared service resources from any affiliates and/or EPCOR Utilities. If yes, please specify with details. It’s noted that the 2013 OEB-approved FTE of 22.92 included 9.35 FTE allocated from Collus Solutions.

EEDO Response:

The FTE data in the two tables excludes shared service resources.

e) If Appendix 2-K includes FTEs allocated from shared services, how does the compensation information (salary, wages and benefits) in the same table correspond with the FTE data?

EEDO Response:

Appendix 2-K excludes FTEs and compensation allocated from shared services.

f) Table 4.4.1-2 on page 41 of Exhibit 4 shows that the total number of employees for 2023 Test Year is 31. The table also provides a breakdown into seven categories. Please reconcile the number of employees in each category with the organizational structure chart. (e.g. For Management category, please indicate which 3 roles in the chart are the corresponding roles.)

EEDO Response:

	Table 4.4.1-2 Category	Headcount	Updated Org Chart per 4-Staff-49 g)

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.

$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.

Ref.	OM&A ($000)	2019	2020	2021	2022	2023	2024	Total
4-SEC-32	Status Quo Forecast	5,331	5,425	5,520	5,616	5,752	5,814	
4-SEC-32	EPCOR Forecast	5,872	5,191	5,110	5,189	5,306	5,350	
EB-2017-0373/0374 1-Staff-1b)	Projected Savings	-541	234	410	427	446	464	
EB-2017-0373/0374 1-Staff-1b)	Cost of 1% Rate Rider	48	49	51	52	54	0	
EB-2017-0373/0374 1-Staff-1b)	Projected Savings adjusted by 1% Rate Rider	-589	185	359	375	392	464	
Appendix 2-JA (IRR dated Aug 25/22)	Appendix 2-JA Actual	5594	6111	5512	6185	6530		
calculated	Variance Actual to EPCOR Forecast	(278)	920	402	996	1,224		3,264
calculated	Variance Actual to Status Quo	263	686	(8)	569	778		2,288
calculated	Variance Actual to Status Quo (adjusted by 1% Rate Rider)	215	637	(59)	517	724		2,034

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%

Suggested structure of the table:

OM&A ($000)	2019	2020	2021	2022	2023
Savings (spent less than Status Quo):					
Item 1	a				
Item 2	b				
Item 3	c				
Costs (spent more than Status Quo):					
Item 1	x				
Item 2	y				
Item 3	z				
Net Cost/Saving for the Year	(x+y+z)-(a+b+c)				
Variance Actual to Status Quo (adj by 1% Rate Rider)	215	637	-59	517	724

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.

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 EEDO system. Based on this ongoing and periodic review, services are added or removed to ensure prudent and safe operation of the system.

Services provided by EEOMI are related to on the ground support provided to Ontario operations and are services which EEDO believes are necessary for the operation of EEDO's utility system. The services are being provided from EOOMI as full FTE are not required to provide these services in EEDO and EEDO is attempting to defray costs for necessary activities by receiving these services on a shared service basis from EOOMI (who is providing these services to EPCOR's other operations in Ontario).

Services provided by EDTI are services which the utility does not have the ability to self-perform and the EEDO affiliate has the expertise to fulfill.

Services provided by EWSI have become nominal and are expected to remain so.

Based on needs of the utility, if EEDO determines that more or less services are required, including affiliate shared services, the decision to add or remove services will be approved by the Director, Operations Ontario Region and the Vice President, Ontario Region in consultation with management at EEDO.

b) Please discuss how the shared services (including corporate shared services) program has contributed to EPCOR Electricity Distribution Ontario's efficiency and providing value and benefits to customers.

EEDO Response:

Affiliate shared services provide efficiency and benefits to customers in a number of different ways. These include:

1. As noted in the response to a) above, the affiliate shared services from EOOMI allows for cost sharing of required services between various operations in Ontario. Without the shared service model, services required for prudent and safe operation of the utility (Management Oversight, HR, HSE, regulatory, customer service, Capital support, OT and SCADA support) would have to be performed by EEDO and would require additional headcounts.

2. Also as noted in the response to a) above, affiliate shared services allow for more one-off support for EEDO activities where EEDO does not have the requisite skills or the available time to undertake the services (such as the services being provided by EDTI).

3. Corporate shared services provide efficiency and benefit to customers primarily in two ways.

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

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.

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

e) Page 66 of Exhibit 4 indicates that with respect to the Regulatory Analyst role, EOOMI shared service will add approximately 0.33 FTE for the 2023 Test Year. Page 72 of Exhibit 4 notes that the level of work required for meeting all regulatory requirements has necessitated an additional regulatory FTE for 2023. Please confirm the amount of FTE that will be added to the Regulatory role in 2023 Test Year (or in both 2022 and 2023, please confirm) as well as the associated cost.

EEDO Response:

As noted per Table 4.4.2-6, for the 2023 Test Year the new regulatory position will allocate 33% to EEDO and 0.33 will be the approximate FTE added. Per Table 4.4.2-7 the 2023 Test Year cost of the Regulatory shared service is $39,715. The $42,123 in c. on page 72 should have agreed to the $39,715 in Table 4.4.2-7.

f) For the Regulatory role, it's noted that the percentage allocator used for both 2022 and 2023 is 33%, but the service cost has been estimated to increase from $29k (2022) to $40k (2023). Please provide explanation for the increase.

EEDO Response:

The Regulatory role was to be filled in 2022 and as a result there was not a full year of costs included in 2022 Bridge Year. The 2023 Test Year amount includes a full year of the role.

g) The Head Office Corporate Allocations (HOCA) is included in Tables 4.4.2-5, 4.4.2-6 and 4.4.2-7 and the estimated allocated cost for 2023 is $36k. Please provide description for this service/functionality and the rationale for this cost to be allocated to EPCOR Electricity Distribution Ontario.

EEDO Response:

The HOCA are costs allocated to EOOMI from EPCOR Utilities Inc. These costs are allocated to EEDO as they are costs of EOOMI providing its services to EEDO.

h) On page 66 of Exhibit 4, the application states that the allocated resource of the VP Ontario Region and the Director Operations Ontario equates to 0.61 FTE in 2023 (in place of the former CEO position at Collus PowerStream). On page 90, it states that the VP Ontario Region and Director Ontario Operations is allocated at 0.7 FTE in 2023 in shared services. Please confirm the FTE equivalency of the VP Ontario Region and the Director Ontario Operations for 2023. Please confirm that this is used

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.

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:

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.

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

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.

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.).

Pre-Acquisition - 2017/2018 Actual		2023 Test Year	
Position	**Cost ($)**	**Shared/Corporate/Embedded Service & Function**	**Cost ($)**
Manager, Ops Network		Information Services (IS) Application Support - EUI Directly Assigned	83,542
		IS Infrastructure Operations - EUI Directly Assigned	94,624
		Information Services (IS) - EUI Allocated Corporate Service	131,460
Total			309,626

Ref: Exhibit 4, Table 4.4.2-12, Table 4.4.2-13

TAB 3

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

Chapter 2 Appendix 2-OB

Preamble:

As noted in the application, on December 3, 2018, EPCOR Electricity Distribution Ontario borrowed $8.1 million from EPCOR Utilities to replace certain debt and to maintain its capital structure. The term of this debt is 30 years with an interest rate of 4.30%.

EPCOR Electricity Distribution Ontario expects to add $1.2 million of new long-term debt in 2022 Bridge Year and $1.2 million of new long-term debt in 2023 Test Year (both are through affiliated debt). EPCOR Electricity Distribution Ontario estimated two interest rates of 5.25% and 5.03% for these two long-term debts respectively and estimated the weighted average cost of long-term debt in 2023 to be 3.98%.

The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, issued on December 11, 2009 (2009 Cost of Capital Report) stated that:

> 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 term.

Question(s):

a) The 2018 cost of capital parameter updates were issued by the OEB via a letter dated November 23, 2017, and applicable to the 2018 rate year, and set a deemed long-term debt rate of 4.16%. The OEB's 2019 cost of capital parameter updates were issued via a letter dated November 22, 2018, and applicable to the 2019 rate year, and set a deemed long-term debt rate of 4.13%. Both the 2018 and 2019 deemed long-term debt rates were known at the time that EPCOR Electricity Distribution Ontario's affiliated debt ($8.1 million) was issued on December 3, 2018. EPCOR Electricity Distribution Ontario's actual affiliated debt rate of 4.30% is higher than the 2018 deemed long-term debt of 4.16%. According to the above noted 2009 Cost of Capital Report, the deemed long-term debt rate is a ceiling on affiliated debt. Therefore, for rate setting purposes, the lower of 4.30% (actual) and 4.16% (deemed) should be applied on this debt until maturity.

   Please confirm if EPCOR Electricity Distribution Ontario will update the long-term debt rate for the above noted debt in Chapter 2 Appendix 2-OB (in 2018 to 2023 tables) in accordance with the 2009 Cost of Capital Report as discussed above. If not, the onus is on EPCOR Electricity Distribution Ontario to fully support its proposed rate with evidence including data, analysis and related information about estimates or offers of market-based debt rates.

EEDO Response:

EEDO believes that all debt rates included in Chapter 2 Appendix 2-OB are supported by market-based data. EEDO does not intend to update the long-term debt rate noted for the December 3, 2018 long-term debt of $8,100,000 as EEDO believes that the 4.30% debt rate is a market rate at the date the debt was issued.

EEDO does not believe it is appropriate to cap affiliated debt at rates which are determined at a point in time (i.e. using the rates in OEB's letter), as this point in time is well in advance of the year in which affiliate debt will actually be taken out by EEDO. Using the 2018 debt issuance as an example, the OEB deemed rate of 4.16% for 2018 was set in the November 23, 2017 letter. The data in this letter utilizes data from September 2017 (Bond Yield and Bond Yield spreads) and consensus forecast data from September 2017 to determine long-term debt rates for a future period (it is understood that the consensus forecast is a forecast rate). Neither underlying Government of Canada (GoC) rates nor utility credit spreads are likely ever to be at these levels when an utility actually issues debt in a future period. Both the GoC and utility credit spreads will fluctuate continually due to market pressures and it would only be possible for EEDO to be at or below this rate if both the actual market rates for GoC and utility credit spreads were at or below these historic levels on the date when EEDO needed to issue long-term debt.

EEDO understands that if it were to go directly to the market (or a bank) and obtain financing directly then this cap would not exist. Given the relatively small size of EEDO, EEDO could not access the debt market (any debt issuances which EEDO would require are much too small to obtain directly in the debt market) and given EEDO's size banks would likely not lend to EEDO at tenors near 30 years. In addition, the historic longer-term debt which EEDO obtained from OSIFA and OILC is no longer available to EEDO.

EEDO believes that issuing 30 year debt is the appropriate tenor of debt to finance it's long-lived utility distribution assets, as it most closely aligns with the life of the assets. EEDO's ultimate parent is able to provide 30 year financing to EEDO which would not otherwise be available to EEDO and prices this debt at market rates, which would also not otherwise be available to EEDO.

In terms of the market pricing of the December 3, 2018 long-term debt, the following methodology is used:

1. EEDO will request debt from it's parent Company, EPCOR Utilities Inc. The request from debt will indicate the amount and tenor (term) of the required debt.
2. EPCOR Utilities Inc. will obtain a quote from one or two schedule 1 banks for the GoC rate on the current date of the request. The banks will use Bloomberg data to provide

a quote for the current GoC level for the tenor of debt requested. This data is used for the GoC/underlying interest rate for the debt issuance.

3. The banks will also provide a quote for EUI's current indicative credit spread on the day the debt is requested by EEDO. EUI credit ratings are A- (S&P)/Alow (DBRS), which are equivalent. The credit spread information is based on secondary trading levels which the Bank as access to and other market data.
4. EUI's credit spread is converted into a credit spread for EEDO based EEDO's deemed credit rating. EEDO is currently rated BBB by EUI and this solid investment credit rating is based on EEDO's stable industry and scope of operations, as well as the business and industry risk of the operation. The difference between EUI's credit spread and EEDO's credit spread is calculated using Bloomberg data which shows the difference between A- and BBB credit ratings. EEDO's total credit spread is calculated as the sum of EUI's credit spread plus the difference between the A- and BBB credit spreads using the Bloomberg data to determine the total credit spread for the debt issuance.
5. A 0.05% transaction fee is added to the totals from 2) and 4) above. EEDO will then decide whether to issue this debt based on the interest rate quoted.

This process was used to determine the rate for the December 3, 2018 debt issuance. The relevant components which the process yielded were as follows:

		A **Date**	B **Value**
1	GoC 30 Year Rate – GoC per Bank (from Bloomberg)	3-Dec-18	2.41%
2	EEDO Credit Spread – EUI Credit Spread (1.57%) and A- versus BBB (0.27%)	3-Dec-18	1.84%
3	Transaction Fee		0.05%
4	**Total Rate**		**4.30%**

b) It's noted that in 2021 there was a new affiliated long-term debt of $2 million with start date of December 15, 2021, and actual debt rate of 3.41%. The 2021 deemed long-term debt rate is 2.85% per the OEB letter dated November 9, 2020. The 2022 deemed long-term debt rate is 3.49% per the OEB letter dated October 28, 2021. Please confirm the appropriate debt rate that should be applied for this debt for rate setting purposes in Appendix 2-OB and provide supporting evidence.

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	

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
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	

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
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	

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
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
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
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	

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
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	

TAB 4

Table 9.1-10 – OEB Cost Assessment Variance Account Balance ($)

	2016	2017	2018	2019	2020	2021	2022F
Principal	27,693	66,415	100,469	135,963	170,912	203,432	235,952
Carrying	124	723	2,337	5,003	7,047	8,123	10,168
Total	**27,817**	**67,138**	**102,806**	**140,966**	**177,959**	**211,555**	**246,120**

Table 9.1-11 – OEB Cost Assessment Variance Calculation ($)

	2016	2017	2018	2019	2020	2021	2022F	Total
2013 CoS Provision	27,632	36,496	36,496	36,496	36,496	36,496	36,496	173,616
Actual Invoices	55,325	74,206	70,550	71,990	72,457	69,016	69,016	344,528
Variance	**27,693**	**37,710**	**34,054**	**35,494**	**35,961**	**32,520**	**32,520**	**235,952**

EEDO has included balance of $246,120 in the Group 2 DVA as part of this application, which includes a forecasted amount for 2022 (based on the 2021 invoice received).

EEDO requests that this sub account be closed upon approval of the 2022 balance.

Other Regulatory Assets, Sub-account Energy East Consultation Costs: On June 13, 2014, the Board established this deferral account to record the Energy East Pipeline Project consultation costs.

EEDO incurred $2,501 in costs related to this hearing in 2015, (including $226 in carrying charges) which has been included in the Group 2 DVA balance as part of this application.

EEDO requests that this sub account be closed upon approval of the 2022 balance.

Other Regulatory Assets, Sub-account Late Payment Penalty ("LPP") Settlement: On July 22, 2010, the Ontario Superior Court of Justice approved a settlement of the LPP Class Action[5]. As its share of this settlement, EEDO was required to pay $46,486 on June 30, 2011 to charity to assist low income electricity users. EEDO received approval from the OEB to recover this amount from ratepayers over a one year period, starting May 1, 2011. The balance remaining in this

[5] EB-2010-0295 Decision and Order, February 22, 2011

Ontario Energy Board

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Ontario

February 9, 2016

To: Regulated Entities subject to the OEB's Cost Assessment

Re: Revisions to the Ontario Energy Board Cost Assessment Model

Please be advised that the Ontario Energy Board (OEB) has revised its Cost Assessment Model (CAM), the methodology used to apportion its costs under section 26 of the *Ontario Energy Board Act, 1998* (Act). The persons or classes of persons that are liable to pay the OEB's costs under section 26(1) of the Act are set out in Ontario Regulation 16/08.

The consulting firm MNP LLP was engaged to undertake a review of the CAM, to ensure alignment with the OEB's current mandate and best practices. The model was last reviewed in its entirety in 2006.

Material changes include:

1. Updating the OEB's direct cost allocations (staff time and Market Surveillance Panel cost) to align with the OEB's mandate.
2. Updating of electricity distribution and gas distribution intra-class allocations from a revenue based allocation to a customer number based allocation, resulting in increased stability and predictability.

The OEB has adopted all of MNP's recommendations effective April 1, 2016. A summary report of MNP's recommendations is posted on the OEB's website.

These changes to the CAM may result in material shifts in the allocation of costs.

It is worth noting that as outlined in the OEB's letter dated January 4, 2016, the OEB's budget has increased for the first time since 2011, to accommodate an expanded mandate and priorities. The budget increase was not a consideration during MNP's analysis of the CAM. The 2015-18 Business Plan and budget is also located on the OEB website.

New Variance Account

The OEB has established the following variance account for electricity distributors and transmitters to record any material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment model effective April 1, 2016:

- *Account 1508 Other Regulatory Assets, Sub-account OEB Cost Assessment Variance*
- Note: the offsetting entry to this account shall be to Account 5655, Regulatory Expenses.

The OEB has also authorized the establishment of a similar variance account by natural gas distributors, OPG and the IESO.

Entries into the variance accounts are to be made on a quarterly basis when the OEB's cost assessment invoice is received. Amounts should be prorated to take into account the effective date of rebased/reset rates, payment amounts or fees (as applicable). Regulated entities are to cease recording amounts in these accounts when their rates, payment amounts or fees (as applicable) are rebased/reset (cost of service or custom IR) incorporating an updated forecast of cost assessments.

Carrying charges at the OEB-prescribed rate are to be calculated using simple interest applied to the monthly opening balances in the accounts (exclusive of accumulated interest) and recorded in a separate sub-account.

Regulated entities are expected to seek disposition of the variance account balances when their rates, payment amounts or fees, as applicable, are next rebased/reset, and the accounts will be closed to any further entries at that time.

Regulated entities are reminded that, in the normal course, any disposition of deferral and variance account balances must meet any OEB default or company-specific materiality thresholds.

Any questions can be directed to John Moon at john.moon@ontarioenergyboard.ca or 416-440-7748.

Yours truly,

Original signed by

Julie Mitchell
Vice President
People, Culture & Business Solutions| Ontario Energy Board

- Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Model
- Advanced/Incremental Capital Module (ACM/ICM) Model (if applicable)

When filing Excel models, applicants should ensure that any links within these models are broken (e.g., links to other documents that are not filed with the application) and the filed versions of such models should be named so that they can be easily identified.

2.0.8 Materiality Thresholds

The applicant must provide justification for annual changes to its rate base, capital expenditures, and operations, maintenance and administration (OM&A) costs, unless otherwise indicated.

The thresholds differ for each applicant, depending on the magnitude of the revenue requirement. A written explanation is required for rate base, capital expenditures, and OM&A costs if the revenue requirement impact of variances exceeds the applicable distributor-specific threshold as follows:

- For distributors with less than 30,000 customers:
  - $10,000 for a distributor with a distribution revenue requirement less than or equal to $10 million[2]
  - 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million
- For distributors with 30,000 or more customers:
  - $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million
  - 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million
  - $1 million for a distributor with a distribution revenue requirement of more than $200 million

A distributor may provide additional details below the threshold if it determines that this may be helpful to the OEB.

[2] The previous $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million still applies to other applications of the materiality threshold, e.g., DVAs, Z factor and eligible investments for the connection of qualifying generation facilities.

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:

The OEB noted that it is expecting applications for the COVID-19 Account to be filed only on an exceptional basis for costs not related to mandated government or OEB-initiated programs; and utilities should generally have been able to manage pandemic-related impacts within existing budgets.[49] Distributors requesting disposition of any amounts recorded in the COVID-19 Account are to file, at a minimum, the following information:

- A discussion regarding the interactions between the COVID-19 Account and other existing generic or utility-specific accounts, including a determination that there is no double-counting between multiple ratemaking mechanisms.
- A calculation showing that the distributor passes the ROE-based means tests to be eligible for recovery of amounts recorded in the account (as prescribed by the COVID-19 Report), including limitations on recoveries when various ROE thresholds are reached, and that the appropriate recovery rates for each sub-account have been applied.[50]
- Supporting calculations for the annual amounts recorded in each of the sub-accounts, including the methodology used to measure incremental costs and savings, as applicable.[51]
- A discussion of causation, materiality, prudence of any amounts recorded in the sub-accounts, including all identified savings and cost reductions.[52]
- A discussion of whether the distributor would be able to reasonably forecast any further entries in the account, up to the effective date of the new rates, so that the account may be disposed in its entirety in the current proceeding (and whether the distributor would be amenable to such an approach).
- A statement confirming that the distributor proposes discontinuation of the COVID-19 Account, effective the same date as the new rates. If this is not the case, supporting rationale is required.

2.9.2 Establishment of New Deferral and Variance Accounts

In the event a distributor seeks an accounting order to establish a DVA, the applicant must file evidence demonstrating how the following eligibility criteria have been met:

- Causation: the forecasted expense must be clearly outside of the base upon which rates were derived.

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[49] Ibid. Page 3
[50] Distributors should refer to Appendix B of the COVID-19 Report for details on how to calculate the means tests, recovery limitations, and sequencing of the calculations.
[51] Distributors should refer to section 4.4, Measuring Incremental Impacts, of the COVID-19 Report.
[52] Distributors should refer to section 4.3.2 Causation, Prudence, and Materiality Criteria, of the COVID-19 Report for specific details on how materiality is to be calculated.

- Materiality: the forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements.
- Prudence: the nature of the costs and forecasted quantum must be based on a plan that sets out how the costs will be reasonably incurred, although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating that the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, applicants must include a draft accounting order which must include a description of the mechanics of the account, including providing examples of general journal entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.

2.9.3 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.[53] Treatment of the LRAMVA is documented in several versions of the CDM Guidelines (2012, 2015, 2021).

In July 2016, the OEB developed a generic LRAMVA work form to provide distributors with a consistent approach to calculate LRAMVA. The LRAMVA work form consolidates information that distributors have received from the IESO.

In December 2016, the OEB indicated in various decisions[54] that changes to an approved LRAMVA amount were not permitted. This policy affects the treatment of verified savings adjustments that may be claimed by distributors. If an LRAMVA amount was approved and disposed, the persistence of the savings adjustment(s) may only be claimed on a "go-forward" basis.[55] Distributors cannot seek recovery of LRAMVA amounts related to savings adjustments for a year in which the corresponding LRAMVA amount has been approved by the OEB on a final basis. For example, if an distributor has received approval of its 2014 LRAMVA balance, excluding 2014 savings adjustments, the distributor must forgo any LRAMVA amounts related to the 2014

[53] EB-2012-0003, Guidelines for Electricity Distributor Conservation and Demand Management
[54] EB-2016-0075 (Guelph Hydro 2017 IRM) and EB-2016-0080 (Hydro One Brampton 2017 IRM)
[55] See EB-2016-0214 for an example (North Bay Hydro 2017 IRM)

Exhibit 9 – Deferral and Variance Accounts

9-Staff-68
Recovery of Income Tax Deferral Account
Ref: Exhibit 9 / Tab 1 / Schedule 1 / pages 25-27
Exhibit 9 / Tab 2 / Appendix D – Draft Accounting Order

Regarding the proposed Recovery of Income Taxes Deferral Account (RITDA), the first reference states:

> EEDO proposes 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.

The draft accounting order in Appendix D states

> Amounts will be recorded in the RITDA on an annual basis only once the loss carry-forward balance for regulatory purposes as identified in Exhibit 6, Tab 1, Schedule 1 Table 6.2-2 of EB- 2022-0028 is fully utilized.

Question(s):

a) Please confirm that the amount of tax loss carry forward referenced in the first paragraph quoted above is not recorded in the account and that only the taxes payable calculated using the tax rate effective at the time of this application is recorded in the account. If not confirmed, please explain.

EEDO Response:

EEDO confirms that the account balance will start at zero and that the tax loss carry forward is not recorded in the account.

EEDO confirms that the taxes payable will be calculated based on the tax rate effective at the time of this application so to avoid double counting the impact of tax rate changes in account 1592.

b) Please indicate the effective tax rate that is anticipated to be used, taking into consideration the 2022 federal budget that updated the range over which the small business deduction is reduced to $10M to $15M.

EEDO Response:

EEDO is not eligible for the small business deduction. The combined Federal/Ontario effective tax rate is currently 26.5%.

c) Please provide a numerical example of the amounts to be recorded in the account annually from 2023 to 2027, using the forecasted tax losses, tax carry-forwards as provided in response to 6-Staff-58.

EEDO Response:

Based on the forecast taxable income from 6-Staff-59 there would not be an amount recorded in account, as the forecast taxable income is less than the loss carry-forward balance. If taxable income were above the $2,890,731 (updated value per 6-Staff-58 c)) loss carry-forward balance, every dollar of taxable income above this level would be multiplied by the effective tax rate and recorded in the account for disposition on EEDO's next rate filing application.

d) The tax rate effective at the time of this application is proposed to be used so that there is no double counting of a recovery between the RITDA and Account 1592 – PILS and Tax variances due to changes tax rates. However, please confirm that the proposed RITDA will allow EPCOR Electricity Distribution Ontario to be kept whole for all other fluctuations that affect taxes (e.g. if taxes payable are higher due to increase in net income), i.e. true up the tax expenses during the incentive period. If confirmed, please explain why this method is proposed. If not confirmed, please explain what is the proposal regarding the PILs expense in conjunction with the RITDA.

EEDO Response:

The intention of the RITDA is to keep EEDO whole in the event that income taxes payable are incurred between the 2023 to 2027 filing period. The 2023 Test Year does not include any income tax expense in rates. EEDO is proposing the RITDA to be able to defer any income taxes actually paid in the period (i.e. in the event that the loss carry-forward balance is fully utilized during the 2023 to 2027 filing period).

9-Staff-69
GA Analysis Workform

9-Staff-104

Ref: 9-Staff-87
9-SEC-47
Exhibit 9/Schedule 1/Tab 1/p.24
IRR Chapter 2 Appendix 2-BA

In response to 9-SEC-47, it states that EPCOR Electricity Distribution Ontario pays CIS costs based on number of active accounts. The agreement between EPCOR Electricity Distribution Ontario and Town of Collingwood is based on number of bills adjusted annually by inflation.

In Exhibit 9 referenced above, it states

> …approximately $200k of fixed billing & collecting costs were excluded from distribution revenue requirement through revenue offsets 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.

a) Please confirm that EPCOR Electricity Distribution Ontario has included the CIS costs in Account 4380 – Expenses of Non-Rate Regulated Activities as shown in Appendix 2-H and the revenues from the Town of Collingwood in Account 4375 – Revenues of Non-Rate Regulated Activities as shown in Appendix 2-H.

EEDO Response:

Confirmed

b) If not confirmed, please explain where the costs and revenues have been reflected in the application.

EEDO Response:

N/A based on above response

c) In Appendix 2-H, the summary table shows the balance in expenses in Account 4380 to be ($775,000) and revenues in Account 4375 to be $890,000, for net revenues of $115,000. In the breakdown of the Account 4380/4375 table below, municipal service expense is greater than revenues by $115,000. Please clarify what the appropriate revenue and expense amounts are.

EEDO Response:

Water/WasteWater Billing	650,000
Water/WasteWater Service Charge	20,000
Water/WasteWater Interest	45,000
Affiliate Recoveries	175,000
4375 - 2023 Total	**890,000**

Water/Wastewater Labour	(350,000)
Water/Wastewater System Fixed	(200,000)
Water/Wastewater System Variable	(50,000)
Affiliate Expenses	(175,000)
4380 - 2023 Total	**(775,000)**

d) Please confirm that the $200,000 represents the portion of the cost paid to external vendors that is recorded in Account 4380, and the remaining portion in Account 4380 are employee costs for providing billing services.

EEDO Response:

Please refer to 9-Staff-47-c above.

i. If not confirmed, please explain what the remaining portion in Account 4380 relates to.

EEDO Response:

Please refer to 9-Staff-47-c above.

ii. If part d is not confirmed, please explain whether the employee costs are currently included in the test year OM&A. If not, please confirm that EPCOR Electricity Distribution Ontario plans to forego recovery of the employee costs for providing those billing services if the agreement with the Town of Collingwood is terminated.

EEDO Response:

Employee costs are not currently included in test year OM&A. EEDO plans to forego recovery of the employee costs for providing those billing services if the agreement with the Town of Collingwood is terminated.

e) Please confirm that $200,000 is the amount that is forecasted to be recorded in the account.

EEDO Response:

Confirmed.

9-Staff-87
New Account
Ref: Exhibit 9 / Tab 1 / Schedule 1 / pages 24-25
Exhibit 9 / Tab 1 / Schedule 2 / Appendix E – Draft Accounting Order

Preamble:

EPCOR Electricity Distribution Ontario is proposing to establish an account 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.

Question(s):

a) If the service contract with the Town of Collingwood is terminated, please explain what the actual recoveries from the Town of Collingwood would be for.

b) EPCOR Electricity Distribution Ontario indicated that it 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). Please explain what these services are and whether some of these services could be reduced in the event that the contract with the Town of Collingwood is terminated.

EEDO Response:

a) If the service contract with the Town of Collingwood is terminated EEDO does not anticipate receiving actual recoveries. The verbiage to net off actual recoveries is to ensure if any recoveries are received that they would be passed onto the rate payer.

b) The majority of EEDO customers are provided a bill with both electricity and Town of Collingwood services on them. A small percentage of bills are provided to Town of Collingwood customers which are not billed electricity. A description of the fixed billing costs and reduction are as follows:

   i. Postage costs would be reduced by approximately 1% as a result of customers that are solely non-electricity customers no longer requiring billing, the remaining postage costs cannot be mitigated.

   ii. Meter reading costs would be reduced by approximately 8% if the Town of Collingwood services were terminated due to a significant portion of meter reading costs being fixed, the remaining meter reading costs cannot be mitigated.

iii. Billing System costs would be reduced by approximately 1% as a result of customers that are solely non-electricity customers no longer requiring billing, the remaining billing system costs cannot be mitigated.

EEDO Response:

EEDO has seen significant growth in recent years in both residential and commercial/residential builds which required the addition of new infrastructure and several transformers. This in itself would have some effect on EEDO's line losses, however EEDO believes that the new infrastructure that was required and installed was done so in a responsible manner to help keep line losses to a minimum. E.g., 500MCM Cu U/G cables, transformers purchased to meet CSA efficiency requirements, etc.

EEDO is continuing to replace small conductor, normally #6 Soild Cu, within its system to a larger conductor, 1/0, 3/0, 336 or 556 depending on circumstances such as single phase or three phase, existing loading and voltage and whether it's distribution or sub-transmission voltages such as 4.16KV or 44KV.

EEDO has proposed to upgrade two substations in Stayner (5MVA to 7.5MVA) in this DSP, which would help alleviate resistive losses due to current and predicted loading of these stations.

EEDO is also adding an additional feeder at their MS9 substation in Collingwood in 2022 to help split and reduce the load on MS9 F2 and MS2 F3. For this project EEDO did look at the option of using a wireless solution to reduce split the load between these two feeders at peak times but it was both time and cost prohibitive for EEDO at this time.

EEDO also has plans for an additional substation in the West end of Collingwood that is being driven by development. This substation would also be used to offset existing load on other substations which in turn will assist in our resistive losses.

9-SEC-47

[Ex.9, p. 24] EEDO has requested a new deferral and variance account, Non-Utility Billing Variance Account, which will be used if the City of Collingwood no longer contracts EEDO to doing their billing:

a) Please provide details of the contract with the City of Collingwood, e.g. terms for renegotiation, expiry date, pricing methodology etc.

EEDO Response:

EEDO (Collus PowerStream Corp.) entered into an agreement with the Town of Collingwood on January 1, 2018 to provide water/wastewater billing services to customers located in the Town of Collingwood (approximately 10,000 customers in total).

The contract expires December 31, 2027 and may be terminated upon 12 months written notice. Pricing is based on an agreed upon 'per bill' rate increased annually due to inflation. EEDO provide this service and maintains records in its existing Customer Information System (CIS).

The agreement is based on a cost-sharing principal as EEDO currently pays CIS costs based on the number of active accounts in its system. Synergies are also achieve through shared staffing and postage/fulfillment costs.

b) Has EEDO investigated with the outside vendors the impact on their costs charged to EEDO should the billing for the City of Collingwood no longer be included in the services to be provided?

EEDO Response:

Yes, EEDO is charged CIS costs based on the number of active accounts based on the existing agreement with UCS (Utility Collaborative Services) which will remain.

Further, postage/fulfillments costs are incurred on a volumetric basis, no based on the content on the bill.

Refer to 9-Staff-87 for additional information.

9-SEC-48
[Ex.9, p. 24 and Table 6.2.2] EEDO has also requested a new deferral and variance account, Recovery of Income Taxes Deferral Account, to cover income taxes once the loss carry-forward is depleted:

a) Please provide information on EEDO's forecast of its taxable income for 2024 to 2027 and when EEDO estimates that the loss carry-forward will have been used up.

EEDO Response:

Please see the response to 6-Staff 58 (d) for EEDO's estimate of 2024 to 2027 taxable income.

b) Table 6.2.2 shows an amount of $ 1,266,169 for 'Judicial Inquiry costs incurred in 2018 to 2021' being deducted from the available loss carry-forward balances for regulatory purposes. Please explain why it is appropriate to reduce the loss carry-forward available for rate payer's using a cost which is to be borne by the shareholder.

EEDO Response:

The Judicial Inquiry costs were not incurred in respect of EEDO providing any utility services to its customers and were not incurred for the prudent and safe operations or construction of

The utility system. The Judicial Inquiry costs are non-Utility costs (and were presented as such in EEDO's annual RRR filings), and should be excluded from any regulatory calculations including loss carry-forward balances available for regulatory purposes.

c) What was the provision for income taxes approved in the 2013 application and what income taxes were paid in each of 2013 to 2021?

EEDO Response:

- 2013 income taxes included in the 2013 application – $67,959
- 2013 actual taxes paid - $109,940