EB-2022-0028

EPCOR Elecricity Distribution Ontario
2023 Cost of Service Application

VECC

COMPENDIUM

February 13, 2023

TAB 1

ONTARIO ENERGY BOARD

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

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

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

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

TAB 2

2) Some projects have contributions yet to be fully received from customers and were inadvertently excluded from the 2022 forecast for customer contributions.

2-Staff-94
Historical Expenditure Clarification
Ref: 2-Staff-17, Historical Expenditures

Preamble:

EPCOR Electricity Distribution Ontario stated that if a project is delayed the project amount would be in the planned capital budget for 2 different years. It would appear that this would double count delayed projects.

Question(s):

a) Please update Chapter 2 appendices – 2-AB with the project cost in the planned capital budget year and not the budget of the year where the deferred project was completed.

EEDO Response:

Please see below for an updated Appendix 2-AB for the 2013-2017 period where double counted delayed projects have been removed.

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period:

2023

CATEGORY	Historical Period (previous plan[1] & actual)														
	2013			2014			2015			2016			2017		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	850,500	515,211	-39.4%	775,500	771,753	-0.5%	775,500	1,306,527	68.5%	768,753	1,998,181	159.9%	752,909	855,614	13.6%
System Renewal	1,050,708	614,162	-41.5%	1,179,656	967,938	-17.9%	1,234,386	789,973	-36.0%	1,694,155	1,229,086	-27.5%	2,115,500	2,166,866	2.4%
System Service	40,000	13,411	-66.5%	40,000	13,696	-65.8%	740,000	157,963	-78.7%	49,200	574,269	1067.2%	51,087	36,226	-29.1%
General Plant	382,000	237,698	-37.8%	505,000	387,068	-23.4%	220,000	133,386	-39.4%	621,150	508,391	-18.2%	626,334	459,192	-26.7%
TOTAL EXPENDITURE	2,323,208	1,380,482	-40.6%	2,500,156	2,140,455	-14.4%	2,969,886	2,387,849	-19.6%	3,133,258	4,309,927	37.6%	3,545,830	3,517,897	-0.8%
Capital Contributions	- 350,000	- 323,111	-7.7%	- 350,000	- 351,231	0.4%	- 350,000	- 745,573	113.0%	- 449,875	- 1,739,589	286.7%	- 449,875	- 527,957	17.4%
Net Capital Expenditures	1,973,208	1,057,371	-46.4%	2,150,156	1,789,224	-16.8%	2,619,886	1,642,276	-37.3%	2,683,383	2,570,338	-4.2%	3,095,955	2,989,941	-3.4%
System O&M	$1,945,300	$2,053,457	5.6%	$2,130,006	$2,169,113	1.8%	$2,230,665	$2,388,712	7.1%	$2,297,585	$2,482,131	8.0%	$2,517,407	$2,189,894	-13.0%

SEC Pre-Settlement Conference Clarification Questions

1. [2-SEC-15d] Please provide a copy of the referenced internal audit.

EEDO Response:

The internal audit report is confidential and contains proprietary information. For this reason, EPCOR will not be filing this document as part of the public record.

2. [2-Staff-33, DSP Risk Ranking Matrix_20220825] The Project Ranking Details identifies 25 projects, with any remaining projects listed as 'future projects':

    a. Please confirm that the matrix only contains System Renewal and System Service projects.

EEDO Response:

Confirmed

    b. How are General Plant and System Access projects taken into consideration in prioritizing projects?

EEDO Response:

General Plant items such as vehicles are ranked based on age, mileage, type of use, engine hours, etc. A condition assessment referenced within the DSP is used to prioritize vehicle replacements. Other items such as communication equipment, computer hardware and software and other equipment utilize an IT/OT priority matrix referenced within the DSP to rank these projects.

System Access projects are not deemed as discretionary so are not prioritized following the methods described within the DSP.

    c. Please explain how the 25 projects were chosen, as some have lower risk scores than those considered 'future' projects.

EEDO Response:

Answer: Some of these projects with higher scores have been completed or are currently underway.

184 8th St is completed due to equipment failure.

233 St Paul St and Elm St are currently underway as they were actually already scheduled to be completed and due to safety concerns with the live front transformers.

Mill St-Louisa St to George St was pushed out as Clearview Twp. is looking at a beautification project on Mill St in Creemore, didn't want to waste funds and do things twice.

Collins-Katherine to Sproule has mostly been re-built due to Bell Fibe to Home project. The remainder will be captured in our Miscellaneous pole replacement program.

Caroline St E&W is to be dome in conjunction with Mill St-Louisa St to George St as these two projects will intersect each other.

44KV Optimization-EPCOR already has one of these automated switches that was installed in conjunction with a project that was required to extend one of our 44KV circuits to feed a new complex. It was felt that this would help lower the Reliability Risk enough that this could be completed in future years.

3. [2-Staff-18, Appendix 2-AA] The following table appears to show that the forecasted costs of replacing a pole have significantly increased in the test year:

   a. Please confirm the numbers shown in the table are correct, and if not, please provide a revised version of the table.

EEDO Response:

Confirmed

	2018	2019	2020	2021	2022	2023	Source
Pole line rebuild	$ 624,202	$ 1,941,992	$ 1,285,638	$ 1,513,561	$ 1,204,953	$ 1,276,043	Appendix 2AA
Pole replacement program	$ 370,665	$ 196,641	$ 587,011	$ 595,826	$ 558,491	$ 582,540	Appendix 2AA
Total	$ 994,867	$ 2,138,633	$ 1,872,649	$ 2,109,387	$ 1,763,444	$ 1,858,583	
Number of poles replaced	108	130	134	162	135	78	2-Staff-18
$/pole	$ 9,212	$ 16,451	$ 13,975	$ 13,021	$ 13,063	$ 23,828	
5 year average $/pole					$ 13,144		

   b. Please explain why the cost to replace a pole in 2023 is significantly higher than in previous years.

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

2-SEC-16

[Ex.2, 2-AB and 2-BA] In the past (2017 to 2021) EEDO has only been able to complete and put in service approx. $3000k (average of in service line) of work. Please explain why EEDO has forecasted completing $4,296k of work in 2023, i.e. forecasting no WIP.

EEDO Response:

The reason EEDO has confidence in delivering the planned $4,296k of capital is that it includes both internal and external labor in completing. One of the main factors leading to the increase relates to the planned system service investment. The main projects in 2023 in system service include the GIS upgrade ($508,602) and the Stayner MS1 upgrade ($689,014). The ArcPro GIS upgrade will be delivered through the GIS vendor, and the main cost driver in the Stayner MS1 upgrade is the transformer and install of the transformer performed by contractors. EEDO's historic capital program has primarily been driven by system renewal projects. EEDO has set our renewal program at a level of ~/year $2M which optimizes resource loading with the reliability and safety benefits from that investment. In the past, EEDO attempted to do too much in the system renewal bucket considering the internal and external resources available resulting in some WIP or carryover projects. EEDO notes that the average annual assets put in service since acquisition (2019-2021) was $3,729k despite COVID impacting the ability to deliver capital in 2020.

2-SEC-17

[Ex.2, 2-AB and 2-BA] As per the footnote on page 13 of the Filing Requirements: Capital in service additions in year X = Capital expenditures in year X + Construction Work in Progress (CWIP) in year X-1 - CWIP in year X. Please provide a table as follows showing this information which reconciles to the information provided in Appendices 2-AB and 2-BA:

	$000	2017	2018	2019	2020	2021	2022	2023
A	Capital Expenditures net of contributed capital							
B	CWIP in previous year							
C	CWIP in current year							
D	In service additions in current year as per formula above							

2.0 RATE BASE (EXHIBIT 2)

2.0-VECC -2

Reference: Exhibit 2, Appendix 2-AB EEDO_2023 Chapter 2 Appendices_202200609.XLSM / EB-2018-0025 August 28, 2019 DSP

a) Please provide the August 28/2019 DSP (EB-2018-0025) and any supporting documents (e.g., Excel spreadsheet appendices).

EEDO Response:

https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber=EB-2018-0025&sortBy=recRegisteredOn-&pageSize=400

b) Please explain why there are significant variances as between the planned net total capital expenditures reported in Appendix 2-AB of this proceeding and the planned net amounts reported in Appendix 2-AB of the August 28, 2019 DSP for the years: 2021 ($3,743 vs $3,391); 2022 ($3,457 vs $3,585) and 2023 ($4,296 vs $3,905);

EEDO Response:

The reason for the difference is that Appendix 2-AB within the 2019 DSP is a forecast of the capital plan, while Appendix 2-AB within the submitted DSP (2023-2027) reflects the updated capital plan in those years. While the DSP is the starting point in each year's capital planning process, the asset management process can result in both a reprioritization of projects based on factors such as safety and reliability, and updated cost estimates.

c) Please provide an amended 2019 DSP (EB-2015-0025) Appendix 2-AB showing the capital contributions and gross and net capital costs separately.

EEDO Response:

In the table below we have provided an amended Appendix 2-AB relating to what was filed in the 2019 DSP (EB-2015-0025) that breaks out capital contributions and shows gross and net capital costs.

	2019	2020	2021	2022	2023
			$ ‘000		
System Access	779	993	1,008	1,034	1,120
System Renewal	2,118	2,450	2,374	2,881	2,865
System Service	300	75	77	79	81
General Plant	569	658	586	264	568
Total Expenditure	**3,766**	**4,176**	**4,045**	**4,258**	**4,634**

EPCOR Electricity Distribution Ontario Inc.
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Phone: (705) 445-1800
epcor.com

August 28, 2019

Board Secretary
Ontario Energy Board
PO Box 2319
27th Floor 2300 Yonge Street
Toronto ON M4P 1E4

Attn: Kirsten Walli

RE: EPCOR Electricity Distribution Ontario Inc. *(formerly Collus PowerStream)* License ED-2002-0518 – Distribution System Plan

On August 14, 2018, EPCOR (under the name Collus PowerStream) received notice of approval of its 2019 cost of service rate application deferral request from the Board Secretary. As a condition of this approval, EPCOR was requested to submit an updated Distribution System Plan Document in the absence of a 2020 cost of service:

> *Collus PowerStream states in its deferral request letter that the corporation has completed a 2018 to 2022 Distribution System Plan. Subject to the outcome of the share transaction applications, the OEB will require Collus PowerStream to file an updated distribution system plan by August 30, 2019.*

In response to this request, please find attached EPCOR's 2019-2023 updated distribution system plan.

If you have any questions, please do not hesitate to contact the undersigned at lirwin@epcor.com or (705)445-1800 ext 2223.

Yours truly,

Larry Irwin
General Manager
EPCOR Electricity Distribution Ontario Inc.
Encl

EPCOR Electricity Distribution Ontario Inc.

2019 – 2023 Distribution System Plan

August 26, 2019 – Ver. 3.3

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

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

Table 1 – EEDO Capital Investment Summary 2019 - 2023

5.2.1 Distribution System Plan overview

5.2.1a Key elements of the Distribution System Plan

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

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

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

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

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

EPCOR Electricity Distribution Ontario Inc.

2023 – 2027 Distribution System Plan

2022 – Ver. 3.0

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

<u>System Access</u>

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.

	2023	2024	2025	2026	2027
System Access	$601,079.00	$614,618.00	$628,848.00	$643,810.00	$659,551.00
System Renewal	$2,066,743.00	$2,208,280.00	$2,095,048.00	$2,168,837.00	$2,103,654.00
System Services	$1,372,616.00	$935,000.00	$668,719.00	$479,037.00	$519,037.00
General Plant	$255,400.00	$711,204.00	$420,764.00	$476,759.00	$579,770.00
Total	$4,295,838.00	$4,469,102.00	$3,813,379.00	$3,768,443.00	$3,862,012.00

	2023	2024	2025	2026	2027
System Access	14%	14%	16%	17%	17%
System Renewal	48%	49%	55%	58%	54%
System Services	32%	21%	18%	13%	13%
General Plant	6%	16%	11%	13%	15%
Total	100%	100%	100%	100%	100%

EEDO Capital Investment Summary 2023 - 2027

5.2.2 Coordinated Planning with third parties

5.2.2a Overview of the consultations

The table below provides a summary of the consultations that EEDO participates in during the year. Details regarding the deliverables and impact to the DSP are in the noted references and discussion following:

Purpose of Consultation	Initiator	Other Participants	Deliverables –Scope and Timing	Impact on DSP
Regional Planning	IESO	IESO, HONI, South Georgian Bay/Muskoka Region LDCs	IESO SGB/M 2020 Scoping Assessment (IRRP & RIP expected in 2022)	No impact on DSP
Customer consultations to provide advice and obtain feedback	EEDO	Customers	Customer survey specific to DSP – Q4 2021; Customer Satisfaction Survey – 2020; Various Social Media interactions	Customer survey preferences are integral part of DSP
Overhead plant locations approval on roadways	EEDO	Towns of Collingwood, Staynor, Thornbury, Creemore, Simcoe County	Town or Region/County approval of proposed EEDO overhead plant location on road allowance	No specific impact on DSP
Road authority work schedule coordination	EEDO	Towns of Collingwood, Staynor, Thornbury, Creemore, Simcoe County	Determination of timing and scope of road authority work that may impact existing EEDO plant	No specific impact on DSP
REG	EEDO	IESO, HONI, other LDCs	No REG investments planned	No specific impact on DSP.

Reference

EEDO_2023 Chapter 2 Appendices_Settlement_20221209.XLSX Filed 2022-12-09

2021			2022			2023	2024	2025	2026	2027
Plan	Actual	Var	Plan	Actual[2]	Var					
$ '000		%	*$ '000*		%	*$ '000*				
1,008,318	1,543,583	53.1%	2,279,019	1,660,796	-27.1%	1,331,751	1,361,747	1,393,275	1,426,425	1,461,301
2,594,023	2,750,666	6.0%	2,025,599	2,265,360	11.8%	2,066,743	2,208,280	2,095,048	2,168,837	2,103,654
101,875	71,150	-30.2%	103,979	102,550	-1.4%	1,372,616	958,750	681,595	479,037	519,037
693,180	99,845	-85.6%	440,548	920,915	109.0%	255,400	709,126	420,764	476,759	579,770
4,397,396	4,465,244	1.5%	4,849,145	4,949,621	2.1%	5,026,510	5,237,903	4,590,682	4,551,058	4,663,762
- 654,494	- 690,144	5.4%	- 1,391,830	- 1,253,036	-10.0%	- 730,672	- 747,130	- 764,428	- 782,615	- 801,750
3,742,902	3,775,100	0.9%	3,457,315	3,696,585	6.9%	4,295,838	4,490,774	3,826,255	3,768,443	3,862,012
$ -	$2,452,353	--	$2,438,752	$2,438,752	0.0%	$2,617,273	$ 2,708,877	$ 2,803,688	#########	#########

TAB 3

As illustrated in Table 4.1.1-2 below, EEDO's distribution revenue per customer is among the lowest of LDCs with a similar customer count based on information from the OEB's 2020 Yearbook of Electricity Distributors. EEDO's 2023 Test Year distribution revenue per customer based on this filing would be $496, which would still put EEDO amongst the lowest amounts in Table 4.1.1-2, even with taking into account the numbers in the comparison are from 2020.

Table 4.1.1-2

Distribution revenue and OM&A per customer[2]

	Electricity Distributor	Distribution Revenue per Customer $	OM&A per customer $	Number of Customers #
1	E.L.K. Energy Inc.	271	196	12,611
2	Wasaga Distribution Inc.	317	248	14,238
3	**EPCOR Electricity Distribution Ontario Inc.**	**409**	**339**	**18,203**
4	Welland Hydro-Electric System Corp.	421	284	24,054
5	Orangeville Hydro Limited	437	255	12,697
6	Westario Power Inc.	456	254	23,953
7	Halton Hills Hydro Inc.	492	298	11,684
8	Grimsby Power Incorporated	498	307	22,564
9	North Bay Hydro Distribution Limited	507	284	24,290
10	Festival Hydro Inc.	536	285	13,936
11	Lakeland Power Distribution Ltd.	548	390	23,547
12	ERTH Power Corporation	558	315	21,654
13	Orillia Power Distribution Corporation	588	430	14,552
14	Innpower Corporation	602	332	19,281
15	Algoma Power Inc.	2,071	1,113	12,124

EEDO's proposed 2023 Test Year OM&A per FTE is $231,691 compared to $200,051 as the 2013 Board-Approved amount. This represents a 15.8% increase over the 10-year period or 1.5% annualized. The increase in OM&A per FTE is driven by the increase in OM&A costs over the 10-year period and is partially offset by an increase in FTEs. As noted in section 4.4.1, EEDO's full-time employee (FTE) headcount has increased from 22.9 FTEs in 2013 to 28.2 FTEs. The primary driver for the increase in FTEs is higher operations FTE as a result of increased operational and capital work demands.

1 – Calculated by applying the OEB's annual inflation parameters (2.2% in 2021, 3.3% in 2022, forecast 3.0% in 2023) to the 2020 Yearbook of Electricity Distributors average OM&A expense per customer of $324
2 – Data Source: OEB 2020 Yearbook of Electricity Distributors

Table 4.2.1-2

Change in OM&A from 2013 OEB Approved to 2023 Test Year by USofA

($)

USoA Account	Account Description	Last Rebasing Year (2013 OEB-Approved)	2023 Test Year	Variance (Test Year vs. Last Rebasing Year (2013 OEB-Approved)
	Reporting Basis	MIFRS	MIFRS	MIFRS
5005	Operation Supervision and Engineering	132,000	340,390	208,390
5010	Load Dispatching	88,500	149,489	60,989
5012	Station Buildings and Fixtures Expense	27,000	56,138	29,138
5016	Distribution Station Equipment Operation Labour	0	5,080	5,080
5017	Distribution Station Equipment Operation Supplie	0	0	0
5020	Overhead Distribution Lines and Feeders Operatio	30,000	74,116	44,116
5025	Overhead Distribution Lines and Feeders Operatio	30,000	32,149	2,149
5030	Overhead Sub transmission Feeders Operation	0	15,612	15,612
5035	Overhead Distribution Transformers Operation	34,800	23,384	-11,416
5040	Underground Distribution Lines and Feeders Opera	8,000	20,461	12,461
5045	Underground Distribution Lines and Feeders Opera	5,000	5,513	513
5050	Opr UG Sub-trasmission Feeders	0	111	111
5055	Underground Distribution Transformers Operation	12,000	7,842	-4,158
5065	Meter Expense	6,000	5,966	-34
5070	Opr Customer Premise - Labour	0	1,189	1,189
5075	Customer Premises Materials and Expenses	0	0	0
5085	Miscellaneous Distribution Expense	60,000	212,571	152,571
5096	Other Rent	172,800	27,057	-145,743
5105	Maintenance Supervision and Engineering	60,000	151,388	91,388
5110	Maintenance of Buildings and Fixtures Distributi	12,000	19,037	7,037
5114	Maintenance of Distribution Station Equipment	52,000	106,165	54,165
5120	Maintenance of Poles, Towers and Fixtures	144,000	97,602	-46,398
5125	Maintenance of Overhead Conductors and Devices	288,000	183,721	-104,279
5130	Maintenance of Overhead Services	172,200	219,331	47,131
5135	Overhead Distribution Lines and Feeders Right of W	101,000	196,617	95,617
5145	Maintenance of Underground Conduit	0	3,124	3,124
5150	Maintenance of Underground Conductors and Devices	117,000	86,312	-30,688
5155	Maintenance of Underground Services	204,000	247,819	43,819
5160	Maintenance of Line Transformers	75,000	47,442	-27,558
5175	Maintenance of Meters	241,700	281,651	39,951
5305	Supervision	84,000	142,745	58,745
5310	Meter Reading Expense	179,000	176,294	-2,706
5315	Customer Billing	522,276	584,902	62,626
5320	Collecting	119,586	141,723	22,137
5325	Collecting Cash Over and Short	0	0	0
5335	Bad Debt Expense	60,000	63,640	3,640
5340	Miscellaneous Customer Accounts Expenses	0	0	0
5410	Community Relations	0	263	263
5415	Energy Conservation	0	0	0
5420	Community Safety Program	0	3,942	3,942
5425	Miscellaneous Customer Service and Informational E	138,000	184,348	46,348
5605	Executive Salaries and Expenses	348,000	1,665,154	1,317,154
5610	Management Salaries and Expenses	134,208	7,147	-127,061
5615	General Administrative Salaries and Expenses	349,392	545,271	195,879
5630	Outside Services Employed	216,000	44,554	-171,446
5635	Property Insurance	28,887	33,264	4,377
5640	Injuries and Damages	64,800	66,078	1,278
5645	Employee Pensions and benefits	3,306	0	-3,306
5646	Employee Pensions & OPEB	0	0	0
5655	Regulatory Expenses	81,000	162,844	81,844
5660	General Advertising Expenses	2,000	16,941	14,941
5665	Miscellaneous General Expenses	69,000	52,900	-16,100
5670	Rent	43,200	0	-43,200
5675	Maintenance of General Plant	30,000	117	-29,883
5680	Electrical Safety Authority Fees	8,040	8,667	627
6205	Donations & LEAP	31,465	12,250	-19,215
	Total	4,585,160	6,530,315	1,945,156

EEDO has amended Appendix 2-C to correct the opening NBV for the 2015 to 2023 years to $15,119,880.

2-Staff-14
Capitalized Overhead
Ref: Exhibit 2 / Tab 1 / Schedule 1 / pages 64-67
Chapter 2 Appendix 2-D

Preamble:

In Chapter 2 Appendix 2-D, EPCOR Electricity Distribution Ontario indicated that the changes in direct wages overhead is due to increased capital work demands and decreased reliance on contractors. The change in burden, administration and general overhead costs is due to the change in capitalized overhead policy from the acquisition by EPCOR Utilities in October 2018.

Question(s):

a) OEB staff calculated the percentage of capitalized burden, administration and general overhead costs as a percentage of total OM&A before capitalization from Appendix 2-D. This percentage and the percentage of total capitalized OM&A from Appendix 2-D is shown in the table below. Both 2018 and 2019 percentages were decreased slightly from the 2017 percentages, instead of the increase expected due to EPCOR Electricity Distribution Ontario's adoption of EPCOR Utilities Inc.'s capitalization policies. Please further explain how the change in capitalization of overhead policy from the acquisition by EPCOR Utilities Inc. in October 2018 affected the amount of capitalized overheads, considering the table below.

EEDO Response:

The decrease in the percentage of capitalized OM&A 2018 and 2019 relative to 2017 is primarily due to the decrease in direct wages being charged to capital relative to operating. This decrease was partially offset by the impact of the change in capitalization of overhead policy. The change in capitalization of overhead policy resulted in a higher percentage of administration and other general overhead costs being capitalized relative to direct wages. The fluctuation in the amount of general overhead costs being charged to capital is further explained in the response to 2-Staff-15.

i. Please explain why capitalized OM&A appears to have increased to a higher level starting in 2015.

EEDO Response:

Capitalized OM&A increased to a higher level starting in 2015 primarily due to hiring additional line crew personnel which allowed a greater amount of resources to be dedicated to capital work. Consequently, more labour, burden, and capitalized overhead were charged to capital relative to operating.

Table 2-3

	2013 Approved	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capitalized Burden, Administration and General Overhead Costs as % of Total OM&A Before Capitalization	4%	4%	3%	9%	7%	10%	9%	8%	7%	10%	9%	9%
% of Capitalized OM&A	8%	8%	7%	15%	15%	21%	19%	16%	14%	20%	18%	17%

b) EPCOR Electricity Distribution Ontario uses a burden rate of 44%, which is a rate provided by EPCOR Utilities Inc. Please explain and discuss whether EPCOR Electricity Distribution Ontario has assessed the appropriateness of the 44% burden rate specifically for EPCOR Electricity Distribution Ontario's operations. If not, why not.

EEDO Response:

Yes, although the rate is provided by EPCOR Utilities Inc. a review of burdened costs is performed annually. The review determines whether the rates used are appropriate by comparing the amounts that have been burdened to capital and operating relative to the actual burden costs. If the rates are deemed to be too high or low an adjustment is made to the rate and to the amounts burdened to capital and operating.

2-Staff-15
Capitalized Overhead
Ref: Exhibit 2 / Tab 1 / Schedule 1 / pages 64-67
Chapter 2 Appendix 2-D

Preamble:

Exhibit 2, Table 2.10-1 shows the capitalized overhead on self-constructed assets. Appendix 2-D shows capitalized OM&A, shown in Table 2-4.

Table 2-4

		2021	2022	2023
Table 2-10-1	Capitalized Overhead ($000's)	485.4	453.8	469.1
Appendix 2-D	Direct Wages ($000's)	690.66	664.34	685.01

TAB 4

Ref: Exhibit 4 / Tab 1 / Schedule 1 / page 60
Exhibit 1 / Tab 1 / Schedule 1 / page 31, Figure 1.3-1

Question(s):

a) It's noted that one of the affiliate companies - EOOMI and EPCOR Electricity Distribution Ontario are not included in Figure 1.3-1 Organizational Chart. Please explain why these two entities are not included. Please update the organizational chart is necessary.

EEDO Response:

An updated affiliate chart has been included below.

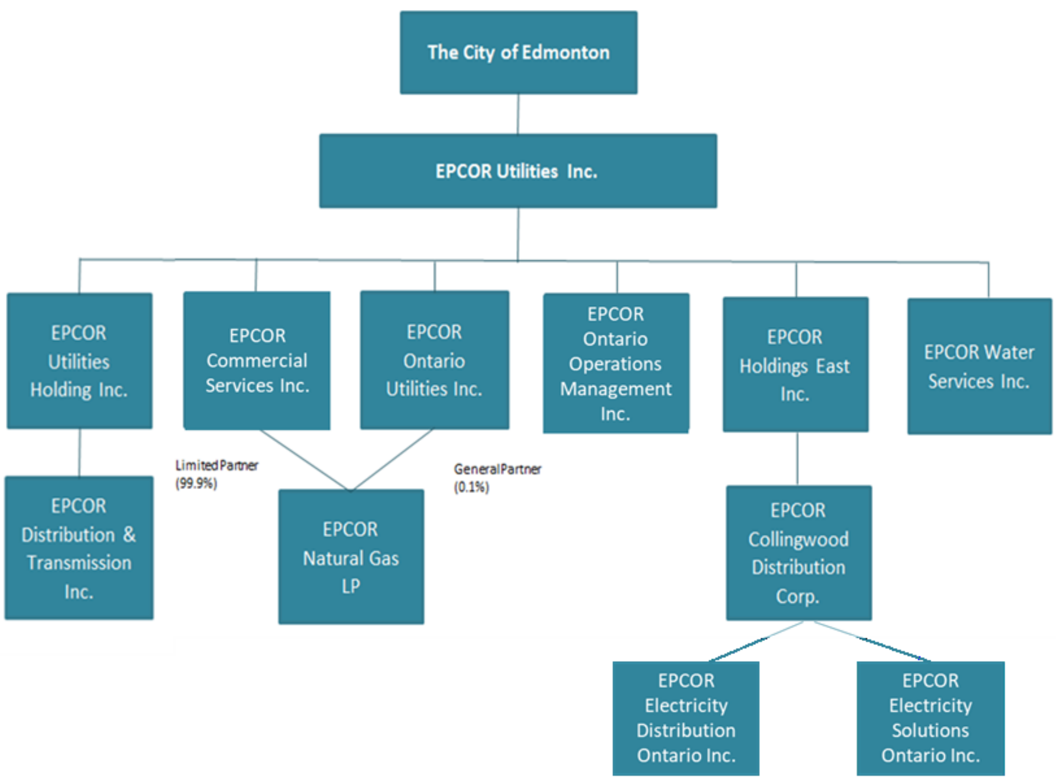


Table 4.4.2-2

Affiliate Shared Services Allocated to EEDO

($)

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

Shared Services Provided by EWSI

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

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

The Shared Services costs are determined on a cost recovery basis in accordance with the ARC and and are reflected in a SLA between the parties. The allocation methodologies have been designed to ensure that the allocation of EWSI's Shared Services costs are fair and reasonable, where the services are more dependent on the relative size of the business/operation that the service are being provided to.

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

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

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

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

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

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

Table 4.4.2-7

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

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

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

Corporate Shared Services from EUI

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

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

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

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

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

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

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

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

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	B	C	D
		2013A	**2023 Test Year**	**Variance**	**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**

Table 4.4.2-10

Corporate Shared Services Allocation Percentages 2022

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

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

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.

in the control room, it is more a matter of paying for more control room operator time to increase the use of the functions within these applications in supporting EEDO's operations.

c) Please explain why it is a more effective and efficient use of resources for these services to be provided by EDTI rather than having these services being performed in-house. Does EDTI provide analogous services to other affiliated companies?

EEDO Response:

EDTI's system control room provides for 24/7 operational surveillance of EEDO's operating system. When there is an unplanned outage, system control is able to provide that first response, and potentially remotely respond without having to engage EEDO local resources. As more field sensors and remotely operated switches are added to the system, this should improve outage recovery time. In the event local resources are required, system control is able to start trouble shooting so that when resources are ready, they can be efficiently directed.

For planned outages, system control is in the best position to be able to create and validate switching orders within their controlled environment using the SmartMap model as their tool. The internal leadership within EEDO is often not available due to competing demands to build the switching orders on a timely basis. This can lead to mistakes and safety incidents. System control, having full visibility of the state of the system, can safely build, test, and validate switching orders.

4-Staff-53
Shared Services Provided by EOOMI/EOUI
Ref: Exhibit 4 / Tab 1 / Schedule 1 / pages 65-74, 90

Preamble:

EPCOR Electricity Distribution Ontario states that due to various changes in the businesses/operations which EOUI/EOOMI were servicing, the 2021 and prior years allocations to EPCOR Utilities' 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 in Exhibit 4.

EPCOR Electricity Distribution Ontario also provided the 2019 to 2023 EOOMI/EOUI affiliated shared services costs allocated to EPCOR Electricity Distribution Ontario in Table 4.4.2-7 in Exhibit 4.

Question(s):

a) Please discuss the triggers for the changes in EOOMI's shared services cost allocation methodology in 2022 (changed from a time basis to specific allocator basis). Please provide the background information for this methodology change.

EEDO Response:

EPCOR has been in the process of setting up an operating hub, with multiple businesses being conducted

As future operations are added in Ontario, it will be increasingly difficult and administratively burdensome for EOOMI staff to adequately and accurately estimate, track and record time spent on the various Ontario operations. A specific allocator also allows for the efficient apportionment of costs when a service being provided by an EOOMI employee is for the benefit of all entities receiving the services (for example when working on rolling out a new policy to all employees in Ontario, the Human Resources function would need to determine how to allocate this shared time to all service recipient entities). A cost allocation methodology allows for easy addition of new operations into the allocation model and provides a consistent methodology to allocate costs to various operations.

In addition, most of the services being provided lend themselves quite well to using a specific allocator to reasonably apportion the costs to the entities receiving the services. For example, headcount is a highly correlated functional cost causation allocator used to allocate costs for Human Resources, and use of the specific allocator versus tracking employee time specifically will reduce administrative time required and can allow the EOOMI employees to focus on providing the required services to the service recipients.

b) Please calculate and provide the total dollar impact for 2023 Test Year of the methodology change. (Please compare the total EOOMI costs allocated to EPCOR Electricity Distribution Ontario based on time spent vs. total costs based on the specific allocators.)

EEDO Response:

Regulatory: Time spent allocation (estimate) 33%, 2023 Test Year cost would be $39,715.

Human Resources: Time Spent Allocation (estimate) 55%, 2023 Test Year cost would be $67,771.

HSE: Time Spent Allocation (estimate) 33%, 2023 Test Year cost would be $68,066.

Customer Service: Time Spent Allocation (estimate) 50%, 2023 Test Year cost would be $68,371.

- 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.

TAB 5

Table 4.4.1-1

Appendix 2-K Employee Costs

Appendix 2-K
Employee Costs

	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
Number of Employees (FTEs including Part-Time)[1]												
Management (including executive)	2.75	3.75	4.06	4.43	4.74	5.33	4.73	5.23	4.34	3.47	2.93	2.60
Non-Management (union and non-union)	20.17	18.60	18.91	19.39	20.66	22.14	24.00	23.27	25.10	24.69	25.75	25.59
Total	22.92	22.35	22.97	23.82	25.40	27.47	28.73	28.51	29.45	28.16	28.68	28.19
Total Salary and Wages including ovetime and incentive pay												
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
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
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
Total Benefits (Current + Accrued)												
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
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
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
Total Compensation (Salary, Wages, & Benefits)												
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
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
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
Total Compensation Breakdown (Capital, OM&A)												
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
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
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

Workforce Planning

The workforce plan from the 2013 cost of service application (EB-2012-0116) was predicated on providing non-utility services to the Town of Collingwood which allowed affiliate employees in Collus Solutions to be allocated between utility activities for Collus PowerStream and non-utility activities for the Town of Collingwood. The Collus PowerStream 2013 OEB Approved FTE of 22.92 included 9.35 FTE (17 headcount) allocated from Collus Solutions for providing services to Collus Powerstream. The remaining 7.65 FTE of the 17 Collus Solutions employees were dedicated to providing services for non-utility activities for the Town of Collingwood.

In 2016, the Town of Collingwood reduced the scope of services received from Collus Solutions to customer billing support. The employees who were no longer providing services to the Town of Collingwood could no longer allocate their costs to the Town of Collingwood and were moved to Collus PowerStream mid-year 2016. The remaining Collus Solutions employees who provided customer billing services were moved to Collus PowerStream at the end of 2016. The 2013 filing FTE estimated that 2.70 FTE of the 7.65 FTE provided customer billing support and 4.95 FTE provided non-customer billing services.

Collus PowerStream mitigated the impact of the additional FTEs to the best of its ability by not back-filling some positions vacated through attrition over time. The end result is that by the end of 2017, management and administrative FTE increased 2.07 FTE to 11.12 from the 2013 Test Year.

Since EEDO was acquired by EPCOR in 2018, EEDO has reviewed its operational and business goals against its workforce requirements, financial strength and the impact on customers. EEDO's workforce plan is designed to ensure the size, experience, knowledge, and skills of its workforce can achieve its objectives to provide safe, reliable, secure, cost–efficient and environmentally responsible operation of EEDO's electrical distribution system.

EEDO has sought to optimize its workforce by leveraging a shared service model that is described in greater detail in section 4.4.2. The shared service model allows EEDO to optimize the overall FTE and operating expense impact of management positions and provide services to areas that EEDO would not otherwise be able to support a whole FTE such as Customer Service, Health Safety and Environment and Operations Engineering. Table 4.4.1-2 below provides an overview of the impacts on headcount up to the year before EPCOR's acquisition of EEDO (2017) and the subsequent change in headcount thereafter.

Table 4.4.1-2
Embedded Employees – Headcount

	Category	2013 Test Year	2017 Actual	2023 Test Year	2013 vs 2017	2017 vs 2023	2013 vs 2023
1	Management	6	6	3	-	(3)	(3)
2	Administration	8	6	6	(2)	-	(2)
3	Billing & Collecting	6	7	7	1	-	1
4	Linesperson	7	10	10	3	-	3
5	Locator	1	1	2	-	1	1
6	Meter Technician	2	2	2	-	-	-
7	Stores Assistant	-	1	1	1	-	1
8	**Total**	**30**	**33**	**31**	**3**	**(2)**	**1**

From 2017 to 2023 the three headcount reduction in Management relates to the elimination of one Hydro Services Manager position and moving the HR Manager and Ops Network & Security Manager to shared service resources as further discussed in section 4.4.2.

Further information related to position and FTE changes from the 2013 Approved year to the 2017 Actual year are discussed after Table 4.4.1-3 below.

Per Table 4.4.2-7, the 2023 Test Year amounts for the Executive oversight is included in row 1 Management Oversight for $223,165 and the HR Consultant position is included in row 3 Human Resources for $58,851.

4.0 -VECC -32
Reference: Exhibit 4, Tab 1, Schedule 1 page 55

"*The majority of EEDO's staff are unionized (1 2023 - 25.6 FTE) through the PWU CUPE Local 1000. There are two collective agreements with PWU, one for Outside workers and one for Inside workers. The PWU Inside workers agreement is new since the previous cost of service filing (EB- 2012-0116) and was established July 1, 2017.*"

a) When do the two agreements reference above expire?

EEDO Response:

Inside employees: expires Dec 17, 2022

Outside employees: expires Dec 16, 2023

4.0 -VECC -33
Reference: Exhibit 4, Tab 1, Schedule 1 Section 4.4.2

a) Please provide a list of the position/FTE eliminations since 2018 that were the result of the replacement of responsibilities to EEDO affiliates.

EEDO response:

Manager, HR (1 FTE)

Manager, Ops Network (1 FTE)

Manager, Billing (0.5 FTE)

Manager, Hydro Services (1 FTE)

b) Do the affiliates of EEDO bill for services on a rendered basis or on the basis of prorated costs of the affiliate?

EEDO Response:

EOOMI and EUI Shared Services are charged to EEDO based on budgeted costs and trued up at the end of the year.

EWSI and EDTI Shared Services are charged to EEDO on a rendered basis.

First, some direct activities are performed through corporate shared services which would otherwise have to be performed directly by EEDO (such examples include payroll processing, accounts payable processing, Treasury-related items, all Tax activities, as well as others). EEDO would have to self perform these activities.

Second, corporate shared services provide governance and oversight to the required activities of EEDO. While services such as HR and HSE are provided to EEDO by EOOMI, a portion of a FTE could not provide all governance and policy support required to ensure proper working of these vital areas. In addition, the individuals providing these services need management support and oversight of their activities and corporate shared services provide this support and oversight.

c) Has there been a cost-benefit study conducted on the shared services (including corporate shared services) that EPCOR Electricity Distribution Ontario receives? If yes, please discuss the major findings of the study and provide a copy in responses.

EEDO Response:

No study has been conducted.

4-Staff-49
Organizational Structure and Number of Employees
Ref: Exhibit 4 / Tab 1 / Schedule 1 / pages 41, 44, 51, 65-68
Exhibit 1 / Tab 1 / Schedule 1 / page 32, Figure 1.3-2

Preamble:

EPCOR Electricity Distribution Ontario states that it employs 32 people and has provided its organizational structure in Figure 1.3-2 in Exhibit 1.

Question(s):

a) Please confirm if the organizational structure provided in Figure 1.3-2 reflects the structure for current year (2022) and/or Test Year 2023.

EEDO Response:

An updated org chart has been included in response to 1g.

b) Are there any proposed changes in the organizational structure in 2023 compared to 2022?

EEDO Response:

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.)

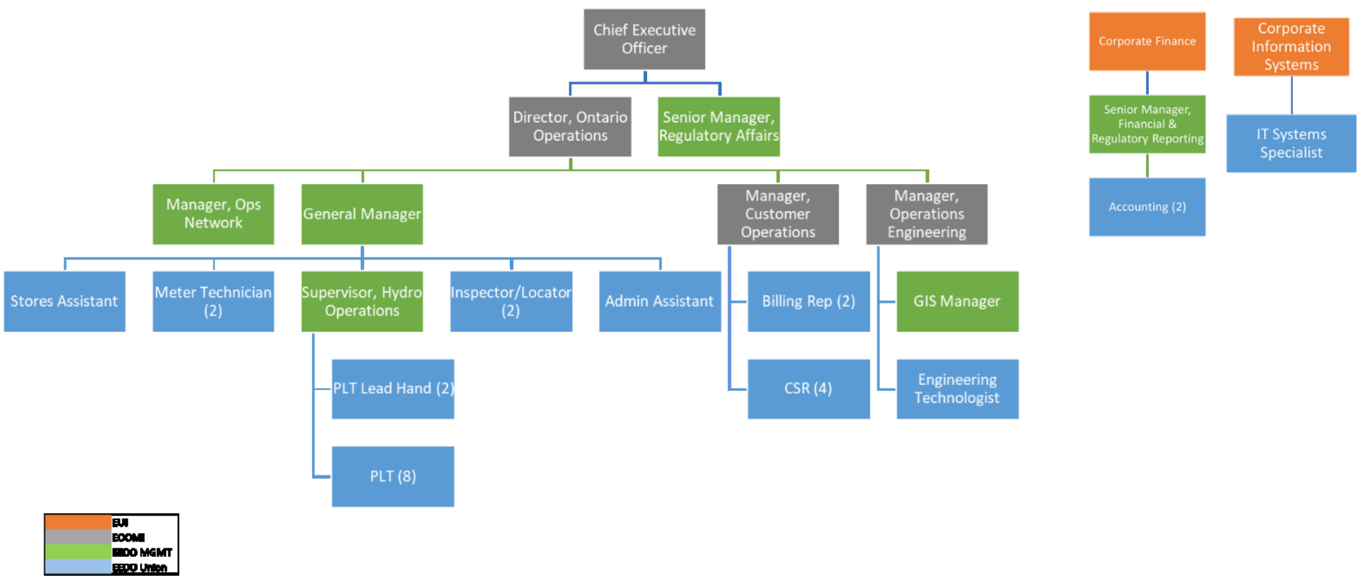
EEDO Response:

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

1-SEC-9
[Figure 1.3-2] Please explain in which company the various positions shown in the Figure reside.

EEDO Response:

An updated org chart has been provided below (consistent with response to 4-Staff-49 g).



1-SEC-10
[Ex.1, p.33] The application states 'EEDO has structured its business operations to reasonably and prudently take advantage of economies of scale and scope through the appropriate use of corporate and affiliate services.' Please provide more details on the savings resulting from EEDO having access to and leveraging the expertise of EPCOR's entities, including an estimation of quantum.

EEDO Response:

There are a number of changes that EEDO has made to take advantage of the corporate and shared services model. More significant examples include:

1. Having access to EOOMI Affiliate Services to provide the following services, which would otherwise likely require a FTE in EEDO given the importance of each of the functions:
    - Management Oversight replacing a full CEO and Manager, Hydro Operations – approximately $120k and 160k respectively

- HR – approximate savings $63k
- Customer Service – approximate savings $59k
- HSE – approximate savings $114k
- OT and SCADA Support (previously 0.60 FTE, now 0.37 FTE) – approximate savings $36k

These amounts do not include oversight and management of these positions (which is largely provided by EUI through Corporate Shared Services), which would not be possible if a single FTE was providing the support with no shared service support. EEDO would either have to take this risk on (i.e. a single individual providing these services, with no oversight or support) or would need to hire out support as needed (to help with things like policy development and implementation, training development and implementation, etc.).

2. Having access to Corporate Shared Services allows EEDO to no longer have a Controller position, which it had in its 2013 approved rates, as various finance functions previously performed at EEDOs level are now performed by Corporate Shared Services (including things like arranging for financing for EEDO, taking care of all tax-related filings and undertakings for EEDO, providing payroll services to EEDO, providing overall financial reporting policy support, etc.). Approximate savings - $125k

1-SEC-11
[Ex., p.52, Table 1.6.3] For the Activities and Program Benchmarking: 2020 Results, please explain the following:

a) Why EEDO's Stations O&M is so much lower than the Ontario Average?
b) Why there is no value for Stations CAPEX?
c) Why Lines Transformers CAPEX is lower than the Ontario Average?

EEDO Response:

a) EEDO notes that the median Station O&M is approximately $8k compared to the Distributor average of $68k which indicates that the average is skewed significantly by LDCs such as Hydro One. It is difficult to determine why EEDO's results differ from the Ontario average without having access to the underlying data for the other LDCs.

b) There was no planned capex in 2020 for stations CAPEX as a result of no identified need for station capital investment in 2020.

c) It is difficult to say why EEDO's results differ from the Ontario average without having access to the underlying costs of the other LDCs.

1-SEC-12
[Ex. 1, p.55] The application states 'EEDO has recently been selected as a delivery organization for NRCan grant funding towards electric vehicle charging infrastructure. This is expected to result in an

TAB 6

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

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

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

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

ii) N/A

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

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

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

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

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

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

Question(s):

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

EEDO Response:

Confirmed

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

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

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

EEDO Response:

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

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

EEDO Response:

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

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

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

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

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

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.

EEDO Response:

The same market-based debt pricing approach was used to price the December 15, 2021 long-term debt, and the same process was followed. The relevant components which the process yielded were as follows:

		A **Date**	B **Value**
1	GoC 30 Year Rate – GoC per bank (from Bloomberg)	15-Dec-21	1.74%
2	EEDO Credit Spread – EUI Credit Spread (1.42%) and A- versus BBB (0.20%)	15-Dec-21	1.62%
3	Transaction Fee		0.05%
4	**Total Rate**		**3.41%**

c) For the two $1.2 million new affiliated debts with start date of December 31, 2022 and December 31, 2023 added in the 2023 Test Year Debt Instruments table in Chapter 2 Appendix 2-OB, EPCOR Electricity Distribution Ontario estimated debt rates of 5.25% and 5.03% respectively. Please provide supporting evidence of the proposed methodology and explanations on how the proposed debt rates are reasonable and market-based.

EEDO Response:

As actual market data for future debt issuances is not available for forecast debt issuances, EEDO had to obtain different market data to estimate rates for 2022 and 2023 debt issuances.

In terms of the OEB deemed long-term debt rates per the OEB's October 28, 2021 Cost of Capital Parameters Letter, EEDO believes these are not appropriate rates for 2022 long-term debt rates. When this application was being prepared, Bloomberg data for May 2022 30 Year GoC rates were 2.89% on average and 10 Year CoG rates were2.92% on average. These values are materially above the average 30 year GoC rates and 10 Year GoC rates (1.80% and 1.26%) respectively used in the OEB's October 28, 2021 letter. In addition, credit spreads are very elevated since September 2021 due to macro-economic factors such as increased geo-political risk and historically high inflation. EPCOR has an A-/Alow credit rating and indicative credit spread data obtained from its banks (which is based on secondary trading in the market) had a range of 1.78% to 1.88% for the May 2022 period. Given this observable market data when the EEDO application was being prepared, it was not reasonable for EEDO to file for rates based on the 3.49% OEB deemed long-term debt rate. Both the underlying market rates and market-based credit spread data were materially elevated, due to material changes in the debt markets.

EEDO's approach to forecasting 2022 and 2023 debt rates was as followed:

1. Forecasts for 2022 and 2023 underlying GoC rates for 30 year debt were calculated as the average of publicly available forecasts from Scotiabank, CIBC and RBC.
2. Current indicative credit spreads for EUI 30 year debt were obtained from the banks (based on secondary market transactions and information on other entities with similar credit ratings).
3. EUI's credit spread was 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.
4. A 0.05% transaction fee is added to the totals from 1) and 3) above.

The relevant components which the process yielded were as follows:

		A **Dated**	B **2022 Bridge Year**	C **2023 Test Year**
1	GoC 30 Year Rate	Forecast	3.07%	2.85%
2	EEDO Credit Spread	Current Market Data	2.13%	2.13%
3	Transaction Fee		0.05%	0.05%
4	**Total Rate**		**5.25%**	**5.03%**

d) Will EPCOR Electricity Distribution Ontario update the estimated debt rate(s) to the OEB's 2023 deemed long-term debt rate once it is issued later in 2022, in a situation that any of the current estimated rates (5.25% and 5.03%) is higher than the 2023 OEB deemed long-term debt rate?

EEDO Response:

Per the response to c) above, EEDO believes that the forecast rates were established using a reasonable, market based approach. In terms of actual debt issued, EEDO will price the debt, using the same methodology noted in a) above on the date the debt is actually issued, using the same market-based data approach. Given that the actual rates for the 2022 and 2023 debt issuances will not be known until these debt issuances are completed, the actual debt rate for the 2022 and 2023 debt issuances may be higher or lower than the forecast rates, due to market movements in both the underlying GoC rates and market movements in utility credit spreads.

EEDO notes that this market-based approach can result in actual debt rates which are below the OEB deemed rates (given that long-term debt rates are determined by the debt market, and the market can move in both directions). For example, the December 1, 2020 rate was 2.88% and this is well below the deemed 2020 OEB rate of 3.21%.

e) As stated in the 2009 Cost of Capital Report, for any new affiliated debt, the deemed long-term debt rate is a ceiling on the allowed rate. The onus is on the distributor to demonstrate that the applied for rate is prudent and comparable to a market-based agreement and rate on arms-length commercial term. If the answer to part b) above is no (considered as a depart from OEB policy), EPCOR Electricity Distribution Ontario is required to fully support its proposed methodology with evidence (including data, analysis and related information) and explanation about how the proposed debt rates are reasonable and market-based debt rates.

EEDO Response:

See responses to a) and b) above. EEDO believes that the methodology used is a market-based approach which takes into effect market data on the day that long-term debt is issued.

f) It’s noted that in the 2023 table in Appendix 2-OB, EPCOR Electricity Distribution Ontario applied proration for principle and interest amounts for the new affiliated debts added. However, this proration has not been applied to the new affiliated debts added in years 2018, 2020 and 2021. Please update the related tables in Appendix 2-OB with the appropriate proration calculations. Otherwise, please provide explanations.

EEDO Response:

EEDO has updated Appendix 2-OB to reflect proration for the new affiliate debt for the years 2018, 2020, 2021, and 2022.

Year: 2021 Test Year

Row	Description	Lender	Affiliated or Third-Party Debt	Fixed or Variable Rate	Start Date	Term (years)	Principal ($)	Rate (%)	Interest ($)	Additional Comments, if any
1	Promissory Note	Town of Halton Hills	Affiliated	Fixed Rate			$13,000,000	4.120%	$133,900	Jan 01- March 31, 2021
2	Promissory Note	Town of Halton Hills	Affiliated	Fixed Rate			$10,200,000	3.210%	$245,565	Apr 01- Dec 31, 2021
3	Smart Meter Term Loan	TB Bank	Third-Party	Fixed Rate			$2,137,212	3.630%	$32,359	Jan 01- May 25, 2021
4	Capital Term Loan #1	TB Bank	Third-Party	Fixed Rate			$1,423,822	3.710%	$22,014	Jan 01- May 25, 2021
5	Capital Term Loan #2	TB Bank	Third-Party	Fixed Rate			$1,835,109	3.710%	$28,366	Jan 01- May 25, 2021
6	Capital Term Loan #3	TB Bank	Third-Party	Fixed Rate			$2,334,807	3.760%	$36,558	Jan 01- May 25, 2021
7	Capital Term Loan #4	TB Bank	Third-Party	Fixed Rate			$3,334,910	3.830%	$53,155	Jan 01- May 25, 2021
8	Capital Term Loan #5	TB Bank	Third-Party	Fixed Rate			$4,406,503	3.860%	$70,745	Jan 01- May 25, 2021
9	Interest Rate Swap #1	TB Bank	Third-Party	Fixed Rate	6-Sep-19	30	$22,080,143	4.095%	$913,540	Jan 01- Dec 31, 2021
10	Capital Term Loan #7	TB Bank	Third-Party	Fixed Rate			$4,049,261	3.910%	$65,829	Jan 01- May 25, 2021
11	Capital Term Loan #8	TB Bank	Third-Party	Fixed Rate			$4,350,436	3.350%	$60,609	Jan 01- May 25, 2021
12	Capital Term Loan #9	TB Bank	Third-Party	Fixed Rate			$4,101,146	3.080%	$52,544	Jan 01- May 25, 2021
13	Capital Term Loan #10	TB Bank	Third-Party	Fixed Rate			$3,063,091	2.800%	$35,682	Jan 01- May 25, 2021
14	Capital Term Loan #11	TB Bank	Third-Party	Fixed Rate	1-Apr-21		$2,800,000	2.450%	$51,450	Apr 01- Dec 31, 2021
15	Interest Rate Swap #2	TB Bank	Third-Party	Fixed Rate	25-May-21	30	$31,077,000	2.951%	$532,176	May 25- Dec 31, 2025
16	Capital Term Loan #13	TB Bank	Third-Party	Fixed Rate			$3,403,896	2.450%	$83,395	Jan 01- Dec 31, 2021
Total							$69,561,039	3.476%	$2,417,887	

5.3 OEB APPENDIX 2-OB COST OF DEBT INSTRUMENTS

Appendix 2-OB below presents capital structure for all required historical years, the Bridge Year (2021) and Test Year (2022), illustrating the weighted average cost of long-term debt.

Table 3a - OEB Appendix 2-OB Cost of Debt Instruments

Year 2022

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Promissory Note	City of Pembroke	Affiliated	Variable Rate			$4,364,000.00	2.78%	$121,319.20
2	Promissory Note	Mississippi Mills	Affiliated	Variable Rate			$902,490.00	2.78%	$25,089.22
3	Promissory Note	Whitewater Region	Affiliated	Variable Rate			$147,000.00	2.78%	$4,086.60
4	Promissory Note	Killaloe, Hagarty	Affiliated	Variable Rate			$172,348.00	2.78%	$4,791.27
5	Capital Financing Loan - Almonte Municipal Substation #4	Infrastructure Ontario	Third-Party	Fixed Rate	30-Jun-20	30	$1,683,654.66	2.56%	$43,101.56
Total							$7,269,492.66	0.02729	$198,387.86

Year 2021

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Promissory Note	City of Pembroke	Affiliated	Fixed Rate			$4,364,000.00	5.37%	$234,425.32
2	Promissory Note	Mississippi Mills	Affiliated	Fixed Rate			$902,490.00	5.37%	$48,479.95
3	Promissory Note	Whitewater Region	Affiliated	Fixed Rate			$147,000.00	5.37%	$7,896.54
4	Promissory Note	Killaloe, Hagarty	Affiliated	Fixed Rate			$172,348.00	5.37%	$9,258.19
5	Capital Financing Loan - Almonte Municipal Substation #4	Infrastructure Ontario	Third-Party	Fixed Rate	30-Jun-20	30	$1,725,318.43	2.56%	$44,168.15
Total							$7,311,156.43	0.04708	$344,228.15

Table 5 - 1: Long-Term Debt

Loan Detail	Year	Term	Interest Rate	P&I Payments	Loan Date	Loan Amount	2021 Test Year Year-End Balance	2021 Test Year Average Principal Balance
Infrastructure Ontario - due April 15, 2021	2011	10	3.90%	$29,403	April 15, 2011	$3,500,000	$0	$24,416
TD - SWAP - due October 2024 - 2014 term loan	2014	10	3.095%	$38,800	October 2, 2014	$4,000,000	$1,261,455	$1,489,758
TD - SWAP - due October 2025 - 2015 term loan	2015	10	2.45%	$56,426	October 15, 2015	$6,000,000	$2,475,013	$2,805,796
TD - SWAP - due November 2036 - CNB replacement loan	2016	20	2.50%	$103,331	November 1, 2016	$19,500,000	$15,425,765	$15,884,080
TD - SWAP - due November 2026 - 2016 term loan	2016	10	2.36%	$46,817	November 30, 2016	$5,000,000	$2,607,760	$2,875,847
TD - SWAP - due October 2027 - 2017 term loan	2017	10	2.88%	$48,004	October 2, 2017	$5,000,000	$3,089,771	$3,350,660
TD - SWAP - due December 2028 - 2018 term loan	2018	10	3.55%	$44,604	December 3, 2018	$4,500,000	$3,313,178	$3,536,310
TD - SWAP - due September 2029 - 2019 term loan	2019	10	2.37%	$51,524	September 3, 2019	$5,500,000	$4,373,491	$4,650,886
TD - SWAP - due September 2030 - 2020 term loan	2020	10	1.56%	$54,034	September 15, 2020	$6,000,000	$5,300,147	$5,604,744
TD - SWAP - forecast - 2021 term loan	2021	10	2.06%	$57,215	December 1, 2021	$6,200,000	$6,200,000	$516,667
Total Principal Balances							**$44,046,579**	**$40,739,163**

2.5.1.3 Cost of Debt: Short Term

For the purposes of preparing this Application, NBHDL has used the cost of capital parameters issued by the Board on November 9, 2020 for 2021 COS rate applications which reflects a deemed short term debt rate of 1.75%. NBHDL proposes no deviation from the Board's cost of capital methodology.

2.5.2 COST OF CAPITAL (RETURN ON EQUITY AND COST OF DEBT)

Table 5-2 below is a reproduction of Appendix 2-OA that demonstrates the elements of the capital structure and cost of capital for the 2015 Board-approved and 2021 Test Year. For 2021, the weighted average cost of capital of 4.80% will be applied to the rate base of $76,227,486, which is explained in detail in Exhibit 2, to determine a return on rate base of $3,655,772 that is included in the proposed revenue requirement.

5.0 COST OF CAPITAL AND RATE OF RETURN (EXHIBIT 5)

5.0-VECC-37

Reference: Exhibit 5

a) For each of the 4 EPCOR Utilities Inc. affiliated debentures listed in Appendix 2-OB please provide the OEB long and short-term deemed debt rate issued with respect to rate changes in the year of the Start Date of the EPCOR debenture.

EEDO Response:

Loan Amount	Start Date	OEB Long-Term Deemed Debt Rate	OEB Deemed Short-Term Debt Rate
$8,100,000	3-Dec 18	4.16%	2.29%
$2,020,000	1-Dec 20	3.21%	2.75%
$2,000,000	15-Dec 21	2.85%	1.75%
$1,200,000	31-Dec 22	3.49%	1.17%
$1,200,000	31-Dec 23	TBD	TBD

b) Where the EPCOR rate is higher than the respective OEB deemed rate please explain the rationale for using the higher rate (For example, at the time of the start date of the 3-DEC-18 debenture issued at 4.30% the Board had issues 2019 cost parameters for long-term debt at 4.13%).

EEDO Response:

Please see the response to 5-Staff-56.

c) What expert is EEDO relying upon when it makes the statement: "*EEDO does not believe that using the 2022 OEB deemed cost of long-term debt is reasonable for the 2022 Bridge Year nor the 2023 Test Year debt 9 issuances anticipated.*" Please provide that expert's report.

EEDO Response:

EEDO, through services provided by the Treasury Shared Service, which is part of the Corporate Shared Services provided to EEDO, is able to current access market data from the various banks which EPCOR uses in debt capital market transactions in order to get current market information for underlying government of Canada yields, as well as current credit spread information. All current market data shows that the underlying rates and credit spreads used in the OEB's 2022 deemed rate calculation are much lower than current market data.

See response to 5-Staff-56 for further information on EEDO's market-based approach to setting long-term borrowing rates included in the application.

6.0 CALCULATION OF REVENUE DEFICIENCY/SURPLUS (EXHIBIT 6)

6.0-VECC-38

Reference: Exhibit 6, page 14

a) Please provide the 2021 and 2022 revenues for each of the accounts set out in Table 6.3-2 for the first 6 months of each year.

b) How many microFit customers does EEDO have and in which account are the revenues recorded?

c) What was the pole attachment charge used for purposes of forecasting the 2023 revenues for Account 4210?

EEDO Response:

a) See the table below,

Account	2021 June YTD	2022 June YTD
4082 Retail	3,693	3,583
4084 STR Retail	31	14
4082 SSS Admin	27,312	27,374
4210 Pole Rental	72,380	71,854
4235 Misc Service	41,611	39,584
4225 - Late Payment	39,017	45,774

b) EEDO has 73 microFit customers. The MicroFit administrative revenues are recorded in USoA 4235.

TAB 7

9.2 Establishment of New Deferral and Variance Accounts

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

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

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

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

Non-Electricity Billing Deferral Account – NBDA

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

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

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

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

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

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

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

Recovery of Income Taxes Deferral Account - RITDA

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

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

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.

9.0 –VECC -53
Reference: Exhibit 9, Tab 1, Schedule 1, page 9 /Table 9.1-5

a) In EB-2017-0373 EEDO proposed, and the OEB granted, a deferral of 5 years for a new rebasing (which normally would have been for a 2018 test year based on its last cost of service application). Had the Utility rebased on the normal timelines it would have incorporated the new OEB cost assessment methodology in its rates from 2018 going forward. Given that, and given the subsequent greater probability of intergenerational customer inequities that now exist due to the prolonged deferment or rebasing, why is it reasonable for current ratepayers pay for the cost deficiency for OEB cost assessments since 2018?

EEDO Response:

OEB cost assessments are a normal condition of license for a distributor and EEDO expects that costs incurred are prudent and recoverable. While the decision to defer was a condition of EEDO's sale, the changes in policy were not an EEDO decision or based on any specific action by EEDO. As a result, EEDO does not believe it to be unreasonable to recover these costs in alignment with Board guidance.

b) Please provide the number of account changes in each year since 2018.

EEDO Response:

See below for the changes in account by rate class since 2018 (*as per RRR*)

	2018	2021	Variance	Variance %
Residential	15,512	16,540	1,028	7%
GS<50	1,768	1,821	53	3%
GS>50	128	124	(4)	-3%
Streetlight	3	3	-	0%
USL	30	30	-	0%
Total	**17,441**	**18,518**	**1,077**	**6%**

9.0 –VECC -54
Reference: Exhibit 9, Tab 1, Schedule 1, page 10

"*As EEDO has completed this transition and no additional costs were incurred*

TAB 8

Source: Interrogatory Responses, Updated Load Forecast Model (20220825), Summary Tables Tab (line 10)

CDM Adjusted (kWh)

kWh	2023 Weather Normal Forecast	CDM Adjustment	2023 CDM Adjusted Forecast
Residential	137,753,321	140,637	137,612,684
GS < 50	45,416,700	569,114	44,847,586
GS > 50	133,307,696	1,738,246	131,569,449
Street Light	1,242,766		1,242,766
USL	396,233		396,233
Total	318,116,716	2,447,998	315,668,719

Source: Settlement Proposal, RRWF (20221209), Tab 10 (Load Forecast)

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Interrogatory Responses

	Customer Class	Initial Application			Interrogatory Responses			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual
1	Residential	17,012	137,646,072		17,012	137,612,684				
2	GS<50kW	1,833	44,991,441		1,833	44,847,586				
3	GS>50kW	127		325,120	127		324,247			
4	Streetlighting	3,318		3,496	3,318		3,496			
5	USL	30	396,233		30	396,233				
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**183,033,746**	**328,616**		**182,856,503**	**327,743**		**-**	**-**

Source: **Settlement Proposal, Cost Allocation Model (20221209), Tab I6.1 (Revenue)**

			1	2	3	7	9
	ID	Total	Residential	GS <50	GS >50	Street Light	Unmetered Scattered Load
Billing Data							
Forecast kWh	CEN	315,668,719	137,612,684	44,847,586	131,569,449	1,242,766	396,233
Forecast kW	CDEM	327,743			324,247	3,496	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		185,000			185,000		
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-					
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	313,087,315	137,612,684	44,847,586	128,988,046	1,242,766	396,233

Source: **Interrogatory Responses, Updated Load Forecast Model (20220825), GSIt 50 Normalized Tab**

Date	Year	Month	GSIt50kW_NoCI	COVID_AM		const	HDD14	CDD14	MonthDays	COVID_AM	Shoulder	Predicted kWh
Dec-21	2021	12	4,419,794	0.50	COVID	492,239	979,504	-	3,005,087	(232,610)	-	4,244,220
Jan-22	2022	1		0.25	0.5	492,239	1,214,683	-	3,005,087	(116,305)	-	4,595,704
Feb-22	2022	2		0.25	0.5	492,239	1,114,886	-	2,714,272	(116,305)	-	4,205,092
Mar-22	2022	3		0.25	0.5	492,239	927,516	4,977	3,005,087	(116,305)	(77,442)	4,236,072
Apr-22	2022	4		0.25	0.5	492,239	561,050	8,735	2,908,148	(116,305)	(77,442)	3,776,426
May-22	2022	5		0.25	0.5	492,239	202,797	156,855	3,005,087	(116,305)	(77,442)	3,663,232
Jun-22	2022	6		0.25	0.5	492,239	24,891	382,777	2,908,148	(116,305)	-	3,691,750
Jul-22	2022	7		0.25	0.5	492,239	-	715,277	3,005,087	(116,305)	-	4,096,298
Aug-22	2022	8		0.25	0.5	492,239	276	671,637	3,005,087	(116,305)	-	4,052,934
Sep-22	2022	9		0.25	0.5	492,239	34,291	341,743	2,908,148	(116,305)	(77,442)	3,582,675
Oct-22	2022	10		0.25	0.5	492,239	264,526	82,947	3,005,087	(116,305)	(77,442)	3,651,052
Nov-22	2022	11		0.25	0.5	492,239	653,675	11,782	2,908,148	(116,305)	(77,442)	3,872,098
Dec-22	2022	12		0.25	0.5	492,239	979,504	-	3,005,087	(116,305)	-	4,360,525
Jan-23	2023	1		0.125	0.25	492,239	1,214,683	-	3,005,087	(58,153)	-	4,653,856
Feb-23	2023	2		0.125	0.25	492,239	1,114,886	-	2,714,272	(58,153)	-	4,263,245
Mar-23	2023	3		0.125	0.25	492,239	927,516	4,977	3,005,087	(58,153)	(77,442)	4,294,224
Apr-23	2023	4		0.125	0.25	492,239	561,050	8,735	2,908,148	(58,153)	(77,442)	3,834,579
May-23	2023	5		0.125	0.25	492,239	202,797	156,855	3,005,087	(58,153)	(77,442)	3,721,384
Jun-23	2023	6		0.125	0.25	492,239	24,891	382,777	2,908,148	(58,153)	-	3,749,903
Jul-23	2023	7		0.125	0.25	492,239	-	715,277	3,005,087	(58,153)	-	4,154,451
Aug-23	2023	8		0.125	0.25	492,239	276	671,637	3,005,087	(58,153)	-	4,111,086
Sep-23	2023	9		0.125	0.25	492,239	34,291	341,743	2,908,148	(58,153)	(77,442)	3,640,828
Oct-23	2023	10		0.125	0.25	492,239	264,526	82,947	3,005,087	(58,153)	(77,442)	3,709,205
Nov-23	2023	11		0.125	0.25	492,239	653,675	11,782	2,908,148	(58,153)	(77,442)	3,930,250
Dec-23	2023	12		0.125	0.25	492,239	979,504	-	3,005,087	(58,153)	-	4,418,678

Model 3: Prais-Winsten, using observations 2012:01-2021:12 (T = 120)				
Dependent variable: GSIt50kW_NoCDM				
rho = 0.484588				
	coefficient	std. error	t-ratio	p-value
const	492,239	300039.8067	1.640580485	0.103640895
HDD14	2,122	95.28114871	22.27068097	2.49E-43
CDD14	3,386	261.3004684	12.95676167	3.74E-24
MonthDay:	96,938	10089.12655	9.608193316	2.28E-16
COVID_AI	(465,220)	79994.57765	-5.815649763	5.62E-08
Shoulder	(77,442)	26415.68367	-2.931654971	4.08E-03