EB-2022-0028

EPCOR Electricity Distribution Ontario Inc.

Responses to OEB Staff Interrogatories

August 25, 2022

EB-2022-0028

EEDO RESPONSE TO OEB STAFF INTERROGATORIES

Exhibit 1- Administrative Documents

1-Staff-1
Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2023 Electricity Distributor Rate Applications webpage.

Note that the 2023 PILs Workform has been updated to reflect the change in small business rate from the 2022 federal budget that updated the range over which the small business deduction is reduced to $10 million to $15 million.

Please note that the 2023 RTSR Workform has been updated with the 2022 UTRs, and 2021 billed usage from the RRRs. Please ensure that 2021 wholesale volumes are also used.

EEDO Response:

EEDO has filed updates to the following models:

EEDO_2023 Revenue Requirement Workform_20220825

- Update to the gross fixed asset balance
- Revised cost of power
- Updated cost allocation

These change has resulted in a revised rate base and revenue requirement:

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses
1	Gross Fixed Assets (average)	(2)	$42,620,963	($255,198)	$42,365,765
2	Accumulated Depreciation (average)	(2)	($11,515,826)	$16,453	($11,499,373)
3	Net Fixed Assets (average)	(2)	$31,105,137	($238,746)	$30,866,392
4	Allowance for Working Capital	(1)	$3,121,641	$16,401	$3,138,043
5	**Total Rate Base**		$34,226,778	($222,344)	$34,004,434

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$6,530,315		$6,530,315		$6,530,315	
2	Amortization/Depreciation	$1,688,100		$1,668,751		$1,668,751	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$25,600		$25,600		$25,600	
7	Return						
	Deemed Interest Expense	$778,865		$773,805		$702,396	
	Return on Deemed Equity	$1,185,616		$1,177,914		$1,069,212	
8	**Service Revenue Requirement (before Revenues)**	$10,208,496		$10,176,385		$9,996,274	
9	Revenue Offsets	$792,010		$792,010		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$9,416,486		$9,384,375		$9,996,274	
11	Distribution revenue	$9,416,486		$9,384,375		$9,384,375	
12	Other revenue	$792,010		$792,010		$792,010	
13	**Total revenue**	$10,208,496		$10,176,385		$10,176,385	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$180,111	(1)

EEDO_2023 Cost Allocation Model_20220825

- Various updates as referenced in the IR responses

EEDO_2023 Chapter 2 Appendices_20220825

- Various updates as referenced in the IR responses

EEDO_2023_GA Analysis Workform_20220825

- Correction of the GA rates used as referenced in the IR responses

EEDO_2023 DVA_Continuity_Schedule_20220825

- Updated carrying charges based on OEB interest rates
- Removal of several balances as referenced in the IR responses
- Adjustment of the COVID-19 balance as referenced in the IR responses
- Reallocation of DVA balances as per existing guidance
- Updated rate riders

EEDO_2023 RTSR WorkForm_20220825

- Updated based on newer version available since original filing

EEDO_2023_LRAMVA_Workform_20220825

- Updated carrying charges based on OEB interest rates
- Adjusted persistence values resulting in a modified claim

EEDO_2023 Tariff Schedule & Bill Impact Model_20220824

- Updated rates and bill impacts based on updates in other exhibits.

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 4.95	18.3%	$ 7.49	19.8%	$ 7.45	15.1%	$ 6.98	5.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 10.79	19.3%	$ 18.96	22.8%	$ 18.90	17.2%	$ 17.71	5.8%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 389.27	37.8%	$ 689.70	38.6%	$ 699.00	22.9%	$ 677.04	4.6%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 1.24	48.8%	$ 1.46	30.5%	$ 1.46	21.4%	$ 1.37	6.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (2,034.80)	-29.5%	$ (1,913.71)	-26.8%	$ (1,910.88)	-25.4%	$ (2,178.97)	-20.9%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 4.95	18.3%	$ 6.36	16.3%	$ 6.33	12.6%	$ 5.92	4.8%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 4.95	18.3%	$ 5.82	18.7%	$ 5.80	16.6%	$ 5.45	9.2%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - Non-RPP (Retaile	kWh	$ 10.79	19.3%	$ 13.75	15.9%	$ 13.69	12.1%	$ 12.81	4.1%

	Current Charges		Proposed Charges		Dx Bill Impact	
	Fixed Charge	Variable Charg	Fixed Charge	Variable Charge	Fixed Charge	Variable Charge
Residential	$ 27.24	-	$ 31.29	$ -	14.87%	
GS <50	$ 23.07	0.0153	$ 26.39	$ 0.02	14.39%	14.38%
GS >50	$ 110.21	3.6042	$ 110.21	$ 4.52	0.00%	25.43%
Street Light	$ 4.03	16.8079	$ 1.95	$ 6.69	-51.61%	-60.20%
Unmetered Scattered Lo	$ 0.56	0.0132	$ 0.79	$ 0.02	41.07%	40.91%

1-Staff-2
Letters of Comment

Following publication of the Notice of Application, the OEB received two letters of comment. Section 23.03 of the OEB's *Rules of Practice and Procedure* states that "Before the record of a proceeding is closed, the applicant in the proceeding must address the issues raised in letters of comment by way of a document filed in the proceeding." If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

EEDO Response:

EEDO received two letters of comment:

- M Rubes: 20220629
- H Singh: 20220628

A response has been submitted via the OEB RESS portal and will be available in the OEB document repository for this proceeding:

https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber=EB-2022-0028&sortBy=recRegisteredOn-&pageSize=400

Attachment: 1-Staff-2_EEDO_Response to Letters of Comment

1-Staff-3
Costs Related to the Premium Paid for Share Acquisition
Ref: Decision and Order, EB-2017-0373 and EB-2017-0374, August 30, 2018, page 14

Preamble:

In the above noted Decision and Order, the OEB approved the sale of the shares of Collus PowerStream Corporation (Collus PowerStream) to EPCOR Utilities Inc. (EPCOR Utilities) with a purchase price of $36.8 million, which included a premium of $17.1 million. As stated in this Decision and Order, assurance that there are no costs related to the premium paid for the acquisition in future rates can be achieved through examination when new rates are proposed.

Question(s):

a) Please confirm that EPCOR Electricity Distribution Ontario has not included any costs related to the premium paid for the share acquisition in the current rebasing application.

EEDO Response:

EEDO confirms that no costs related to the premium paid for the share acquisition are included in the current rebasing application.

1-Staff-4
Achieved Return on Equity (ROE)
Ref: 2016 to 2021 ROE Data

Preamble:

As summarized in the table below, for 2019 to 2021 period, EPCOR Electricity Distribution Ontario has achieved less than the deemed regulated ROE, and the achieved ROEs are outside the dead band of +/-300 basis points.

Table 1-1: Return on Equity

ROE	2016	2017	2018	2019	2020	2021
Deemed	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%
Achieved	10.03%	11.65%	11.94%	2.77%	-1.77%	3.47%
ROE delta	1.05%	2.67%	2.96%	-6.21%	-10.75%	-5.51%

Question(s):

a) EPCOR Electricity Distribution Ontario underearned in 2019 to 2021. Please explain the drivers for the low achieved ROE in these recent years. Please consider all significant changes in the factors involved in the calculation of the achieved ROE.

EEDO Response:

2019

The ROE delta of 6.21% can be broken down into two parts,

1. Return component (-3.93%)

The return component is lower as a result of several factors,

- Higher operating expenses ($1.1M) that have not been fully offset by the increase in revenues ($0.7M) as a result of annual IRM increases and customer growth. The increase in operating expenses not related to inflation is primarily related to higher shared service costs from affiliates and integration costs in excess of cost savings.

- Higher depreciation ($0.3M) as a result of growth in ratebase that has not been fully offset by the increase in revenues ($0.2M) as a result of annual IRM increases and customer growth.
- Temporary decrease of 1% in residential rates as part of the approved acquisition of Collus Powerstream
- These decreases to the return component are partially offset by the increase in revenue relating to the return on ratebase as a result of annual IRM increases and customer growth.

2. Deemed equity (-2.38%)

The deemed equity is $2.7M higher relative to the 2013 filing primarily as a result of growth in PP&E ($5.8M) higher over the seven year term since the last rebasing in 2013. PP&E also increased in 2019 as a result of the IFRS change for property under finance lease which accounts for $1.7M of the increase.

In addition, the working capital allowance has increased primarily due to the increase in cost of power ($6.5M) and higher operating expenses ($1.1M).

2020

The ROE delta of 10.75% can be broken down into two parts,

1. Return component (-7.74%)

The return component is lower as a result of several factors,

- Higher operating expenses ($1.5M) that have not been fully offset by the increase in revenues ($0.8M) as a result of annual IRM increases and customer growth. The increase in operating expenses not related to inflation is primarily related to higher shared service costs from affiliates and higher labour OM&A as a result of a lower proportion of labour spent on capital work as a result of COVID-19 mitigation measures.
- Higher depreciation ($0.3M) as a result of growth in ratebase that has not been fully offset by the increase in revenues ($0.2M) as a result of annual IRM increases and customer growth.
- Lower income tax as a result of lower net income ($0.1M)
- Higher interest expense ($0.3M) that has not been fully offset by the increase in deemed interest expense in revenues ($0.1M) as a result of annual IRM increases and customer growth.

- Temporary decrease of 1% in residential rates as part of the approved acquisition of Collus Powerstream

These decreases to the return component are partially offset by the increase in revenue relating to the return on deemed equity as a result of annual IRM increases and customer growth.

2. Deemed equity (-3.01%)

   The deemed equity is $4.0M higher relative to the 2013 filing primarily as a result of growth in PP&E ($8.2M) higher over the eight year term since the last rebasing in 2013.

   In addition, the working capital allowance has increased primarily due to the increase in cost of power ($12.0M) and higher operating expenses ($1.5M).

2021

The ROE delta of 5.51% can be broken down into two parts,

1. Return component (-2.34%)

The return component is lower as a result of several factors,

- Higher operating expenses ($1.0M) that have not been fully offset by the increase in revenues ($0.9M) as a result of annual IRM increases and customer growth. The increase in operating expenses not related to inflation is primarily related to higher shared service costs from affiliates in excess of cost savings.
- Higher depreciation ($0.3M) as a result of growth in ratebase that has not been fully offset by the increase in revenues ($0.2M) as a result of annual IRM increases and customer growth.
- Lower income tax as a result of lower net income.
- Higher interest expense ($0.3M) that has not been fully offset by the increase in deemed interest expense in revenues ($0.1M) as a result of annual IRM increases and customer growth.
- Temporary decrease of 1% in residential rates as part of the approved acquisition of Collus Powerstream
- These decreases to the return component are partially offset by the increase in revenue relating to the return on deemed equity as a result of annual IRM increases and customer growth.

2. Deemed equity (-3.18%)

The deemed equity is $4.3M higher relative to the 2013 filing primarily as a result of growth in PP&E ($9.6M) higher over the eight year term since the last rebasing in 2013.

In addition, the working capital allowance has increased primarily due to the increase in cost of power ($8.0M) and higher operating expenses ($1.0M).

1-Staff-5
Customer Engagement
Ref: Chapter 2A Filing Requirements for Small Utilities, page 10

Question(s):

As required in the Chapter 2A Filing Requirements, please document any communications with unmetered load customers, including street lighting customers, and how EPCOR Electricity Distribution Ontario assisted them in understanding the regulatory context in which distributors operate and how it affects unmetered load customers.

EEDO Response:

EEDO currently has 3 Streetlight and 30 USL Customers. Along with all forms of customer engagement activities submitted as part of Appendix 2-AC, EEDO also held regular touch points with the Town of Collingwood staff to discuss rate impacts along with changes to connection counts to align with new development activity. The largest component of change in customer bills was the LRAMVA recovery due to substantial streetlighting projects that took place in 2017. Further to this, EEDO also explained the process of rebasing along with the rationale for the decrease in streetlighting rates as this is the first rebasing that has taken place since the projects were completed.

1-Staff-6
APB
Ref: Exhibit 1 / Tab 1 / Schedule 1 / page 52

Preamble:

The OEB issued an updated APB report dated April 29, 2022, with 2020 results included.

Question(s):

a) Please discuss EPCOR Electricity Distribution Ontario's year-over-year performance for each of the ten APB programs with 2020 results.

EEDO Response:

1. Billing O&M – ($30.03/customer in 2020 vs $28.37 in 2019) – Primarily due to increased postage, billing system and billing contractor costs.
2. Metering O&M – ($23.22/customer in 2020 vs $25.32 in 2019) – Primarily due to lower operations meter costs from decreased contractor costs due to timing of usage and lower training costs due to training cycle.
3. Vegetation Management O&M – ($21.03/pole in 2020 vs $30.86 in 2019) – Primarily due to vegetation management cycle, EEDO follows a 3-year plan and 2020 costs represent a low point in the cycle.
4. Lines O&M ($2,248/circuit km in 2020 vs $1,862 in 2019) – Primarily due to increase in performing disconnect/reconnects starting in September of 2019 vs full year in 2020 and increased storm restoration work in 2020 compared to 2019.
5. Stations O&M ($33,275 MVA per station in 2020 vs $12,794 in 2019) – Primarily due to increase in contractor costs to remediate deficiencies identified through review upon acquisition.
6. Poles, Towers O&M ($21/pole in 2020 vs $10 in 2019) – Primarily due to increased time spent by linecrew on pole maintenance relative to 2019.
7. Stations Capex (nil/MVA per station in 2020 vs nil in 2019) – No planned capex in either year
8. Poles Capex ($11,151/pole addition vs $15,114 in 2019) – Decrease in pole capex per pole partly due to performing work internally once EEDO obtained pole stringing equipment vs contracting out.
9. Line Transformers Capex ($8,893/line transformer addition vs $1,834 in 2019) – Increase due to timing of putting assets into service, transformers that were indicated as additions in 2019 were put in service in 2020.
10. Meters Capex ($0.26/customer vs $7.00 in 2019) – EEDO believes the 2020 reported number only reflects interval meters and excludes smart meters. When smart meter capex ($126k) is included the year over year capex per unit is similar

1-Staff-7
Implementing the Green Button Initiative
Ref: OEB Letter dated November 1, 2021

Preamble:

Distributors are required to implement Green Button by November 1, 2023. The OEB has approved the establishment of a generic deferral account for rate regulated distributors to record the incremental costs directly attributable to the implementation of the Green Button initiative.

Question(s):

a) Please provide EPCOR Electricity Distribution Ontario's current progress of implementing the Green Button initiative. Does EPCOR Electricity Distribution Ontario have a project plan in place to implement Green Button? If yes, please provide a high-level description of those plans. If not, please advise when the distributor expects to have a project plan in place.

EEDO Response:

EEDO is in process of procuring a vendor to assist with the management and implementation of a Green Button solution with an expected selection to be made by the end of September 2022. An implementation timeline will be developed along with the third party. EEDO is also participating in a pilot project led by its ODS (Operational Data Store) provider, which is currently among the potential vendors being investigated.

b) Please clarify if EPCOR Electricity Distribution Ontario has recorded any incremental costs directly attributable to the implementation of the Green Button initiative in the generic deferral account.

EEDO Response:

EEDO has incurred approximately $300 in incremental costs for the purchase of the Green Button NAESB Standard, which is a requirement.

c) Please confirm EPCOR Electricity Distribution Ontario has not proposed any capital or OM&A costs associated with the implementation of the Green Button initiative for the 2022 bridge year and the 2023 test year.

EEDO Response:

Confirmed

1-Staff-8
Adoption of IFRS
Ref: Exhibit 1 / Tab 1 / Schedule 1 / page 28
Accounting Procedures Handbook, Article 510, page 9

Preamble:

Subsequent to EPCOR Electricity Distribution Ontario's last rebasing for 2013 rate year, EPCOR Electricity Distribution Ontario transitioned to International Financial Reporting Standards (IFRS) effective January 1, 2014. EPCOR Electricity Distribution Ontario indicated that there were no material differences in the 2023 revenue requirement between Canadian Generally Accepted Accounting Principles (GAAP) and IFRS.

Article 510 of the Accounting Procedures Handbook indicates that there is an exemption that allows an entity to recognize all cumulative actuarial gains and losses in opening retained earnings on the transition date independent of the previous accounting policy under previous GAAP.

Question(s):

a) Please confirm that any impact from the recognition of actuarial gains and losses in opening retained earnings on the transition date was not material. If not confirmed, please quantify the cumulative actuarial gains or losses that was recognized in opening retained earnings on the transition date.

EEDO Response:

EEDO confirms that the impact of the transition to IFRS on January 1, 2014 opening retained earnings was immaterial.

Under Canadian GAAP, the corporation amortized the excess of the net actuarial gains or losses over 10% of the accrued benefit into the statement of comprehensive income on a straight-line basis over the remaining service period of active employees to full eligibility. At the date of transition, all previously unamortized actuarial gains were recognized in other comprehensive income, which resulted in an increase of $58,639 to the employee future benefits on the balance sheet and a decrease of $58,639 to accumulated other comprehensive income.

1-Staff-9
Leases
Ref: Exhibit 1 / Tab 1 / Schedule 1 / page 146 / Appendix B – 2021 Audited Financial Statements
Exhibit 4 / Tab 1 / Schedule 1 / page 17
Chapter 2 Appendix 2-BA

Preamble:

Note 11 and Note 17 of EPCOR Electricity Distribution Ontario's 2021 Audited Financial Statements indicates that EPCOR Electricity Distribution Ontario has a right-of-use asset of $1,160,526 and lease liability of $1,268,814 as at the 2021 year-end. Note 17 further indicates that the lease was effective in 2018. In Appendix 2-BA, Account 2005 – Property Under Finance Lease has a net book value of $1,160,526 as of December 31, 2021 and $816,867 as at December 31, 2023.

In Exhibit 4, it states that the variance in General & Admin OM&A is partially due to $216k in lease costs from Collingwood Public Utilities Services Board as EPCOR Electricity Distribution Ontario's lease with the Town of Collingwood has been included as a capital lease and lease amortization has been included in Account 6045.

Question(s):

a) IFRS 16 – Leases was effective for reporting periods beginning on or after January 1, 2019. Please discuss whether the adoption of IFRS 16 had a material impact on EPCOR Electricity Distribution Ontario's financial statements.

EEDO Response:

The implementation of IFRS 16 on January 1, 2019, did not result in any adjustment to the opening balance of retained earnings. However, it had an impact on the statement of financial position as a result of the recognition of Right of Use (ROU) assets and lease liabilities with respect to the lease of the EEDO's building. On the initial application of IFRS 16, EEDO recognized the ROU assets of $1,676,316 and lease liabilities for the same amount.

The impact of the application of IFRS 16 related to EEDO's lease contracts, on the statements of comprehensive income has not been material as the depreciation expense related to ROU assets and finance expenses on lease liabilities recognized under IFRS 16 are largely offset by reduction in operating lease expense, which were recognized in net income before applying the new standard.

b) Please confirm that the lease from Collingwood Public Utilities Services Board included in EPCOR Electricity Distribution Ontario's 2013 cost of service rate application has expired, and the lease with the Town of Collingwood has not been previously included in EPCOR Electricity Distribution Ontario's rates. If not confirmed, please explain.

EEDO Response:

Confirmed, the lease with Collingwood Public Utilities Service Board that was included in the 2013 cost of service rate application was terminated on acquisition of Collus PowerStream and the lease with the Town of Collingwood was entered into on October 1, 2018.

c) For each lease, if any, that EPCOR Electricity Distribution Ontario had included for recovery in a prior rate application and is continuing to request recovery of these leases in the current application, please:

   i. indicate whether these leases were treated as operating or finance leases for regulatory purposes, and whether costs were included in OM&A or rate base in the prior application.

   ii. indicate whether these leases are proposed to be treated as operating or finance leases for regulatory purposes, and the corresponding amounts included in OM&A or rate base in the current application.

   iii. quantify the revenue requirement difference between including the costs in OM&A versus capital in the current application.

EEDO Response:

There are no leases that had been included in recovery in a prior rate application that EEDO is continuing to request recovery of in the current application.

d) For any leases where there was a change in accounting treatment between a prior application and the current application, please explain how EPCOR Electricity Distribution Ontario plans to treat this revenue requirement difference for rate purposes.

EEDO Response:

There are no leases noted that had a change in accounting treatment between a prior application and the current application. For the new lease with the Town of Collingwood, EEDO proposes including the PP&E right of use asset in ratebase with the return of and return on ratebase being included in revenue requirement. Payments related to the lease (interest portion and principal) have been excluded from OM&A.

Exhibit 2 – Rate Base

2-Staff-10
2022 Bridge Year Actual
Ref: Appendix 2-AA

Question(s):

a) Please update actual capital expenditures for 2022 bridge year in Appendix 2-AA format (and update other related tabs in Chapter 2 Appendices accordingly). Please specify for which months actual data has been used versus forecast.

EEDO Response:

To prepare the forecast, actual data through June 2022 has been used.

The following Appendix 2 tabs have been updated to reflect the updated 2022 capital expenditures.

Appendix 2-AA

Appendix 2-AB

Appendix 2-BA

Appendix 2-C

2-Staff-11
Controllable Expenses in Working Capital Allowance Calculation (WAC)
Ref: Exhibit 2 / Tab 1 / Schedule 1 / page 4 Table 2.1.1-1
RRWF Tab 4 Rate Base
Exhibit 2 / Tab 1 / Schedule 1 / page 55 Table 2.5-1
Exhibit 4 / Tab 1 / Schedule 1 / page 2

Preamble:

The amount of Controllable Expenses for 2023 that is included in Table 2.1.1-1 in Exhibit 2 and Tab 4 of RRWF is $6,555,915. In Table 2.5-1 on page 55 of Exhibit 2, the amount for 2023 Controllable Expenses is $6,442k. In Exhibit 4 (and related Chapter 2 Appendices), the estimated total OM&A for 2023 Test Year is $6,530,315.

Question(s):

a) Please provide explanations for differences among the above three noted OM&A expenses values (especially why the OM&A amount used in the WAC calculation is different than the one estimated in Exhibit 4).

EEDO Response:

The controllable expenses of $6,555,915 includes an additional $25,600 of other expenses to the $6,530,315 OM&A in the 2023 test year. The $25,600 of other expenses are for letter of credit and guarantee costs that are not accounted for in the OM&A USoA accounts and have been included separately in the RRWF. The letter of credit and guarantee costs relate to parental guarantees which have been issued by EEDO's parent for the IESO and the Town of Collingwood loans as required by the IESO and Town of Collingwood.

The amount on Table 2.5-1 on page 55 of Exhibit 2 is incorrect and should have been $6,556k.

b) Please confirm the correct OM&A amount to be used in the WAC and rate base calculations and make updates to related models and workforms if necessary.

EEDO Response:

The correct controllable expense amount is $6,555,915 which is comprised of OM&A of $6,530,315 and other expenses of $25,600 as described in the response to a).

2-Staff-12
Fixed Asset Continuity Schedule
Ref: Chapter 2 Appendix – 2-BA
Exhibit 1 / Tab 1 / Schedule 1 / page 146 / Appendix B – 2021 Financial Statements

Preamble:

The 2021 fixed asset net book value in Chapter 2 Appendix 2-BA appears to be different than the corresponding amounts in EPCOR Electricity Distribution Ontario's 2021 financial statements by $148,005. The difference is shown in the table below.

In the EPCOR Electricity Distribution Ontario's Reporting and Record Keeping Requirements (RRR) 2.1.13 Financial Statement Reconciliation filed with the OEB, there are adjustments to property plant and equipment netting to $148,005 relating to MIST meters.

Table 2-1

	USoA in Appendix 2-BA	Appendix 2-BA ($)	Audited Financial Statements ($)	Difference ($)
Total PP&E	All remaining USoA	33,018,462	33,166,468	-148,006

Intangibles	1609, 1611, 2060	908,420	908,420	0
Right of Use Asset	2005	1,160,526	1,160,526	0
Deferred Revenue	2440	- 6,264,120	- 6,264,120	0
Total Capital		**28,823,289**	**28,971,294**	**- 148,005**

Question(s):

a) Please reconcile and explain the 2021 fixed asset net book value difference between Appendix 2-BA and EPCOR Electricity Distribution Ontario's financial statements.

EEDO Response:

The difference is due to the financial statement classification of the MIST meters. Under IFRS the MIST meters are presented as PPE which differs from the regulatory accounting treatment where it is presented as a regulatory deferral account. This item has been shown in the annual reconciliation between our annual audited financial statements and OEB trial balance as part of the RRR reporting requirement (2.1.13).

2-Staff-13
Depreciation
Ref: Exhibit 2 / Tab 1 / Schedule 1 / page 7
Chapter 2 Appendix 2-C, 2-BA

Preamble:

In Chapter 2 Appendix 2-C, the book values used to calculate depreciation is as follows:

Table 2-2

	Accounting Standard	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1)	Opening Gross Book Value of Assets Acquired After Policy Change
2013	CGAAP	$0	$31,038,990
2014	CGAAP	$15,119,880	$0
2014	MIFRS	$15,119,880	$0
2015	CGAAP	$15,119,880	$1,801,231
2015	MIFRS	$8,599,156	$1,801,231

Question(s):

a) EPCOR Electricity Distribution Ontario adopted the deemed cost exception upon transition to IFRS, where the deemed cost under CGAAP became new IFRS cost basis and accumulated depreciation was set to $0. This is represented by the 2014 opening net book value of $15,119,880 in Appendix 2-C. The opening net book value of existing assets as at the policy change is generally not expected to be revised after. Please explain why the 2015 opening net book value in Appendix 2-C was revised to $8,599,156, how this amount was determined, and the impact to depreciation expense.

EEDO Response:

The revision to opening net book value of existing assets in 2015 MIFRS from $15,119,880 to $8,599,156 was done in error. The following accounts were impacted:

Account	Description	Opening NBV difference
1830	Poles, Towers & Fixtures	82,398
1835	Overhead Conductors & Devices	755
1840	Underground Conduit	1,410
1845	Underground Conductors & Devices	2,570
1850	Line Transformers	34,623
1855	Services (Overhead & Underground)	847
1995	Contributions and Grants	6,398,121
Total		6,520,724

The impacts of the error is listed included in the table below, note that the largest opening NBV difference (1995 - Contributions and Grants) had no impact to the depreciation calculation as a result of using a nil average useful life in Appendix 2-C.

Year	Depreciation impact
2015	5,158
2016	4,708
2017	4,669
2018	4,665
2019	4,664
2020	4,299
2021	4,299
2022	4,298
2023	4,297

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

	Burden, administration and other general overhead costs ($000's)	716.47	668.48	693.66
	Total Capitalized OM&A ($000's)	1,407.13	1,332.82	1,378.67

Question(s):

a) Please explain how the capitalized overhead on self-constructed assets in table 2-10.1 correlates to the capitalized OM&A amounts in Appendix 2-D. Please explain what other costs are capitalized in the amounts shown in Appendix 2-D.

EEDO Response:

i. The capitalized overhead correlates with the proportion of direct wages spent on capital work relative to operating work. The allocation of overhead costs to capital versus operating is dependent on proportion of capital work to operating work being performed. All other things being equal, as more wages are charged to capital work, more overhead would be charged to capital vs operating.

ii. The other costs included in capitalized overhead include salaries of staff from the Storekeeper, Engineering staff, IT and GIS staff, Hydro Supervisor and senior management to the extent their work was capital in nature. In addition, the other costs include departmental OM&A costs from the Storekeeper, Engineering, and IT.

2-Staff-16
Historical Expenditures
Ref: Chapter 2 Appendix 2-AA

Preamble:

In Appendix 2-AA, EPCOR Electricity Distribution Ontario provided historical aggregated spending for road authority and customer demand from 2013-2023.

Question(s):

a) Please separate road authority and customer demand spending for both capital expenditures and capital contributions.

EEDO Response:

EEDO has updated Appendix 2-AA to separate road authority and customer demand spending for capital expenditures and capital contributions.

2-Staff-17
Historical Expenditures
Ref: Chapter 2 Appendix 2-AB

Preamble:

Between 2013 and 2017 EPCOR Electricity Distribution Ontario's actual capital expenditures were $10.1 million but the planned capital expenditures were $14.5 million. EPCOR Electricity Distribution Ontario's spending was $4.4 million (30%) below planned expenditures.

Question(s):

a) Please explain the reasons for the underspend over 2013 through 2017.

EEDO Response:

There was not a planned capital expenditure underspend of 30%. Certain projects were deferred to subsequent years, and thus appear in more than one annual budget.

The planned capital expenditures for each of the years in 2013 through 2017 represent the planned budget of capital expenditures in that year. A significant amount of the variance from plan relates to projects that were budgeted in subsequent years due to deferring projects to subsequent years.

For example, the 10^{th} Line – Poplar to Mountain Road pole line rebuild project was included in the 2013 budget for $0.5 million but was delayed until 2014, this project was included again in the 2014 budget where it was completed on budget. This example would result in a variance of the actual capital expenditures being less than planned capital expenditures by $0.5 million over the 2013-2017 period.

One of the main drivers behind deferring projects was due to a shortage of power line technicians, especially in 2013 and 2014. It was very difficult to recruit and retain into Collingwood. This drove EEDO to develop a strategy to build apprentices within the organization.

b) Please list the capital projects that were not completed in EPCOR Electricity Distribution Ontario's 2013 to 2017 plan.

EEDO Response:

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

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

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

Preamble:

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

Question(s):

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

EEDO Response:

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

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

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

EEDO Response:

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

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

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

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

2-Staff-19

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

Preamble:

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

Question(s):

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

EEDO Response:

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

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

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

Preamble:

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

Question(s):

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

EEDO Response:

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

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

b) How has EPCOR Electricity Distribution Ontario planned for the electrification of vehicles given that Canada's Emissions Reduction Plan mandates that all new light-duty vehicle sales will be net-zero emission vehicles by 2035?[1] What challenges will the uptake of EVs bring to EPCOR Electricity Distribution Ontario during the DSP period? Has EPCOR considered the use of Level 1 versus Level 2 EV chargers and the difference in load associated with each?

EEDO Response:

As mentioned above, EEDO is ensuring that it has the necessary tools to be able to properly identify areas of potential constraint or overloading caused by customers charging electric vehicles. While public charging applications can be assessed and planned, residential charging can be more problematic. EV charging will challenge the design principle of load diversity. Load diversity implies that not all customers on a distribution transformer will be at peak demand at the same time. EV charging behaviour may result in peak consistently occurring when owners return home and plug in.

EEDO anticipates that there will be distribution transformers that may require upgrading to manage increased EV adoption. It is not anticipated that this will be material enough to pre-emptively upgrade transformers during this DSP period. However, should EV adoption accelerate, it is possible that EEDO may need to propose a plan in the form of an interim capital module should the investment be deemed large enough.

EEDO does not have an implementable solution to resolve this issue that other utilities do not have. This will present a universal challenge of electrification. Infrastructure will have to be increased in order to manage this increase in electrical loading. To avoid over building, data analytics and grid intelligence will be key to making optimal infrastructure investments. EEDO's investment into SmartMap and its GIS model is setting itself up to be able to operate in this complex environment mitigating the impact to our rate payers in the long run.

EEDO has not considered the difference between level 1 and level 2 chargers. EEDO is aware though that level 3 (fast chargers) are becoming more common in public spaces. In addition to that, EEDO has learned that it is becoming more common to install 100KW level 3 chargers than that of 50KW given the increased speed of charge.

c) Through the federal Greener Home Initiative, residents are being encouraged to switch to cold climate heat pumps for space heating.[2] Has EPCOR Electricity

[1] 2030 Emissions Reduction Plan – Canada's Next Steps for Clean Air and a Strong Economy
[2] NRCan, Canada Greener Home Initiatives

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

EEDO Response:

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

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

EEDO Response:

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

2-Staff-21

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

Preamble:

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

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

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

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

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

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

Question(s):

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

EEDO Response:

This statement should read 891.

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

EEDO Response:

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

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

EEDO Response:

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

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

EEDO Response:

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

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

Preamble:

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

Question(s):

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

EEDO Response:

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

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

EEDO Response:

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

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

EEDO Response:

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

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

d) Please explain the underspending between 2020 and 2022.

EEDO Response:

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

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

EEDO Response:

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

2-Staff-23
Asset Condition Assessment (ACA) - Poles
Ref: METSCO Asset Condition Assessment, pages 9, 39

Preamble:

According to the asset condition assessment, wood poles only have a 20% data availability indicator (DAI) for remaining pole strength and 60% DAI for visual inspections. On page 39, it states that for an asset to have a valid health index, it must meet 70% DAI across the condition parameters. It is also recommended that EPCOR Electricity Distribution Ontario consider collecting accurate hammer tests and a more robust visual inspection.

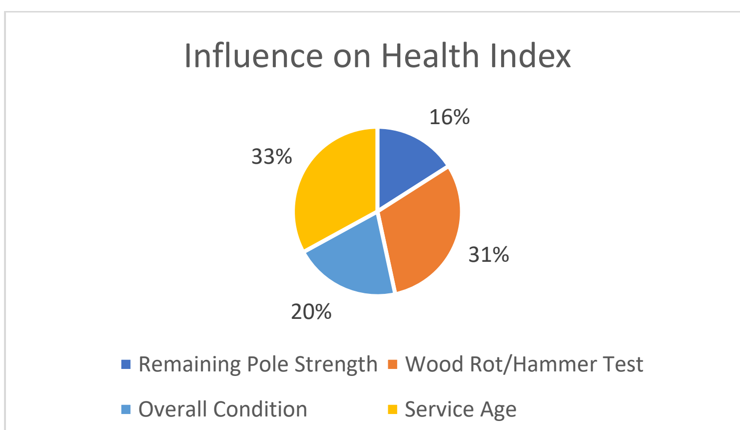
Question(s):

a) Please confirm that the health index is still largely based on pole age. If not, please explain how the low DAI for pole strength and visual inspections does not decrease the accuracy of the health index.

EEDO Response:

(From Metsco) The condition criteria used in the Health Index formulation have the weights and DAI shown below. The product of these represents the influence that each condition criterion has on the overall Health Index. The figure below highlights the influence of each criterion, where service age is the largest individual influence but is far from a majority.

Degradation Factor	DAI (%)	Weights
Remaining Pole Strength	18%	8
Wood Rot/Hammer Test	46%	6
Overall Condition	46%	4
Service Age	99%	3



Indeed, the accuracy of the Health Index calculation will increase as EEDO digitizes more pole testing and inspection results. As these data are collected, EEDO will be able to continuously rerun the calculation and verify which poles have the greatest need for replacement each year.

b) When will EPCOR Electricity Distribution Ontario implement the recommendations to improve its ACA and when will those recommendations be implemented?

EEDO Response:

EEDO will be implanting a new inspection/condition assessment process in accordance with the new CSA regulations for overhead and underground inspections. Our auditor of ESA 22/04 recommended that this be implemented in 2023 along with the release of the CSA regulation and new policies and standards for ACA.

2-Staff-24
Telecommunications
Ref: Distribution System Plan, page 9
OEB Letter – Capital Planning to Support Telecommunications Projects, January 11, 2022

Preamble:

Reference 2 states the new regulation made under Part VI.1 of the Ontario Energy Board Act, which was added by the Supporting Broadband and Infrastructure Expansion Act, requires a distributor to consult telecommunications entities in its service areas and provide the number of consultations, a summary of the consultations, and whether the consultations were reflected in the capital plans. EPCOR Electricity Distribution Ontario stated that it has not held specific consultations but incorporates accommodation for future communications technology when planning its electrical infrastructure.

Question(s):

a) Please provide a plan where EPCOR Electricity Distribution Ontario will consult with any telecommunication entity in its service area in the future. The plan should include an estimate of when the consultations would happen and the process EPCOR Electricity Distribution Ontario will use to incorporate those consultations into its infrastructure planning.

EEDO Response:

Once our filing is complete, EEDO will reach out to the telecommunication entities in our service area to explain all of our approved pole line rebuilds. This will be done in the fall of 2022.

b) Please confirm if all of EPCOR Electricity Distribution Ontario's poles can accommodate future communications infrastructure. If not, please provide the percentage of poles that can accommodate future communications infrastructure.

EEDO Response:

Not all of our poles can accommodate communication infrastructure because they do not meet current day standards for clearances. These poles would be addressed on a project by project basis. EEDO does not have definitive data on the number of poles in this situation, but estimates approximately 25%.

c) When was the last time that telecommunications entities were consulted?

EEDO Response:

Telecommunication entities are consulted on a project by project basis. The last time may have been when Bell conducted the fibre to the home project between 2015 to 2016.

2-Staff-25
Reliability
Ref: Distribution System Plan, pages 22-23

Preamble:

Defective equipment is the second largest cause of the frequency of outages.

Question(s):

a) Please break down the defective equipment cause code by the equipment that failed.

EEDO Response:

Please refer to the table below:

	2017	2018	2019	2020	2021
5.11-Overhead Transformer	2		3	2	3
5.12-Overhead transformer Fuse		1	1		
5.13-All Other Fuses	1		2	1	2
5.14-Overhead Transformer Switch	1	2	5	2	1
5.15-Overhead Transformer Lightning Arrestor					
5.16-Overhead Transformer Conductor		1		1	
5.17-Overhead Transformer Connection	4	5	1		
5.18-Overhead Transformer Insulator	1				
5.21-Cable Joints					
5.22 -Padmount Transformer			1		1
5.23-Pad Mount Switchgear-MVI					
5.24 -Recloser					
5.25 -Underground - Elbow, terminator, pothead, bushing		1			1
5.26-Cutomoer-Owned Equipment					
5.27-Blown Fuse on DIP or Riser		1	1		
5.28-Dip or Riser Switch				1	
5.3-Lightning, surge or elbow arrestor					
5.4-U/G Primary Cable					3
5.5-U/G Secondary Cable				3	
5.6-Line Harware			3	3	2
5.7-Station Equiptment			1		
5.8-Terminations/Elbows					1
5.91-Overhead Primary Cable					
5.92-Overhead Secondary Cable	1		1		
5.93-Other Equiptment		2			

The majority of the customer outage hours are due to loss of supply and tree contacts.

b) How has EPCOR Electricity Distribution Ontario addressed loss of supply? Please break down the tree conact cause code by growth and fallen tree.

EEDO Response:

EEDO has included investment in this DSP period to implement fault line indicators at key points on its system. These fault line indicators will better pin point where either EEDO or Hydro One has suffered a tree contact. This will improve the speed of time it takes to resolve an outage caused by a tree contact. Many loss of supply outages in EEDO are due to tree contacts on Hydro One's feeders.

c) What clearance standard does EPCOR Electricity Distribution Ontario uses for tree trimming?

EEDO Response:

1m for secondary lines and 4m for primary lines in accordance with Ontario Electrical Safety Code Regulation 75-712.

The outage hours for tree contacts are 10 times longer than defective equipment.

d) What is EPCOR Electricity Distribution Ontario's vegetation management budget?

EEDO Response:

EEDO has a plan to spend $417,361 in aggregate over the next three years of the DSP on vegetation management. EEDO has signed a three year MSA for this work in order to contain costs. EEDO anticipates extending this contract through the back two years of this DSP period.

e) How does EPCOR Electricity Distribution Ontario optimize the balance between capital expenditures and OM&A to maximize improvement in reliability (i.e., spending less on pole replacement and spending more on tree trimming)?

EEDO Response:

Pole replacement is conditioned based maintenance, whereas vegetation management is a cyclical area maintenance program. A pole line failure will have a much greater impact to reliability and public safety than a single tree contact driving the need for greater investment and condition assessment.

For example if a tree fails and faults a line, operations clears the tree and restores power within hours. If a pole line fails, this would involve a rebuild under an outage condition resulting in a greater reliability impact.

Based on data provided by EPCOR Electricity Distribution Ontario, adverse weather interruption hours have increased in 2020 and 2021.

Table 2-6: Adverse Weather Customer Hours of Interruption

Year	Adverse Weather Hours of Interruption	Total Hours of Interruption	% of Total
2017	1,005	76,996	1%
2018	1,304	43,333	3%
2019	459	62,953	1%
2020	6,880	67,192	10%

2021	20,354	80,703	25%

f) What was the reasoning for the increase in customer hours of interruption due to adverse weather in 2020 and 2021?

EEDO Response:

EEDO's operating area experienced an increase in wind related storm outages in the years 2020 and 2021 as compared to historical years.

g) Please provide sub-cause code adverse weather hours of interruption from 2017 to 2021 (wind, ice, snow, major storm, and other).

EEDO Response:

The majority of adverse weather hours were due to wind. EPCOR does not maintain any further breakdown of adverse weather in our system.

2-Staff-26
Pole Replacement
Ref: Distribution System Plan – System Renewal – Misc. Pole Replacement, page 63

Preamble:

EPCOR Electricity Distribution Ontario stated that on average it replaces 40 poles per year in this program.

Question(s):

a) Please provide the number of poles replaced for each year in this program between 2017 to 2021.

b) Of the poles provided in part A please provide the number of poles that were replaced on a reactive basis.

EEDO Response:

a) Please refer to EEDO's response to 2-Staff-18-(b)
b) This data is not readily available, EEDO projects the vast majority of poles were not replaced on a reactive basis (i.e. windstorm or car accident etc..)

2-Staff-27
Pole Replacement Program Cost
Ref: Distribution System Plan, page 62

Preamble:

The following table outlines the cost breakdown for the miscellaneous pole replacement program as outlined in App.2-AA_Capital Projects:

Table 2-7: Miscellaneous Pole Replacement Program Actual Cost (2018-2022)

2018	2019	2020	2021	2022
$370,665	$196,641	$587,011	$595,826	$582,540

The following table outlines the cost breakdown for the miscellaneous pole replacement program in the 2023-2027 DSP:

Table 2-8: Miscellaneous Pole Replacement Program Forecasted Cost (2023-2027)

2023	2024	2025	2026	2027
$582,540	$582,540	$582,540	$582,540	$582,540

Both programs were expected to address approximately 40 pole replacements per year.

Question(s):

a) How were the increased cost of lumber and the increase to inflation implemented into the capital cost of the program from 2023 to 2027, given that future program spending is less than 2020 spending?

EEDO Response:

There are various factors that influence the actual costs of pole replacement beyond just the cost of the material. Productivity, weather, ground and ground conditions are examples. Inflationary increases will have to be offset through productivity and planning.

2-Staff-28
Pole Line Rebuilds 2023
Ref: Distribution System Plan – System Renewal – Pole Line Rebuilds, page 68

Preamble:

EPCOR Electricity Distribution Ontario provided three individual neighborhood projects in the pole line rebuild program in 2023.

Question(s):

a) Please provide the project description for the Osler Bluff Road – Feeder Tie project.

EEDO Response:

The Osler Bluff Road - Feeder Tie project involves the replacement of approximately 26 existing poles at the South end of Osler Bluff Rd as well as to install new poles between the North and South feeds to provide a tie in point between the two.

Currently, EEDO's distribution system feeds customers on Osler Bluff Rd from Hwy 26 in the North to Mountain Road in the South. The North part of Osler Bluff Road is radial fed by MS6 Feeder 4 from Forest Drive to 223 Osler Bluff Rd with a three phase circuit. The South end of Osler Bluff is fed from Mountain Road to 207 Osler Bluff Rd with a single phase circuit from MS2 Feeder 3. From a reliability and safety perspective, the replacement of existing poles and installation of new poles will not only provide a tie-in point between the North and South feeds, but also allow EEDO to have all of their poles within their service territory as currently the poles feeding Osler Bluff Rd from the North are not.

b) The average cost per pole replacement in the Osler Bluff Road project is $21k per pole but for the other two projects is $60k per pole. Please explain the driver for the higher costs.

EEDO Response:

There are many line items that make up the cost estimate of a pole line rebuild project. Each one is somewhat different depending on the design, area, and number of ancillary assets impacted. For example the Osler Bluff Road project involves the replacement of 26 poles, while Clarkson Crescent Rear Lot is only 6. However, Clarkson Crescent Rear Lot will require an estimated $110,532 of restoration, rock excavation, crane, easements or upgraded services in the scope. This scope is not required on the Osler Bluff Road project. For actual pole costs, the Osler Bluff project includes 26 x 60' poles at $1597.01/pole while Clarkson Crescent Rear Lot includes 4 x 35' poles at $445.14, 1 x 40' pole at $621.50, and 1 x 45' pole at $806.00.

2-Staff-29
SCADA Controlled 44kV Overhead Switch
Ref: Distribution System Plan – System Service – SCADA Controlled 44kV Overhead Switch, page 89

Preamble:

EPCOR Electricity Distribution Ontario stated that it plans to automate and sectionalize the 44kV system to improve restoration times in the event of an outage.

Question(s):

a) Please explain which reliability cause codes this is intended to improve and what is the expected improvement in terms of hours.

EEDO Response:

EEDO customers have been impacted by some material outages that could have been mitigated by having some automated and/or remotely operated switches. The first relates to cause code 5, defective equipment. A piece of customer owned 44KV equipment failed twice in 2021, resulting in the entire 44 KV feeder being taken out right back to the TS. As this was a result of non-EEDO equipment, the cause code entered was loss of supply, cause code 2. If we were able to sectionalize the 44 KV feeder remotely, we would have been able to isolate the faulted section and bring customers back on line much faster than having to manually isolate and restore. It is estimated that this may have saved 11,000 customer hours of interruption.

In another case, EEDO customers were impacted two years straight by trees not in our right of way, which had rotted at the base and fallen on our 44 KV lines. The resulted in large tree contact outages in 2020 and 2021. EEDO applied for MED status given these trees were weakened during storms and rotting conditions, but were denied this status. 44KV automated and/or remotely operated switches will permit for EEDO to quickly isolate the faulted section of line and pick up the load from adjacent 44 KV feeders. This could potentially have an impact of mitigating roughly 10 to 20,000 customer hours if these types of events are mitigated.

b) Does EPCOR Electricity Distribution Ontario’s 44kV system have the capability to back feed itself through automated tie switches?

EEDO Response:

EEDO does have capacity on adjacent 44 KV circuits to be able to pick up load, however, this is not through automated switches.

2-Staff-30
ArcGIS Pro
Ref: Distribution System Plan – System Service – ArcGIS Pro and Utility Network Migration, page 91

Preamble:

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

Question(s):

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

EEDO Response:

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

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

EEDO Response:

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

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

Preamble:

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

Question(s):

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

EEDO Response:

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

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

EEDO Response:

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

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

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

EEDO Response:

The above was the peak at each station.

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

MS1 Concurrent Value: 2207.875 kW

MS2 Concurrent Value: 3749.686 kW

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

EEDO Response:

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

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

EEDO Response:

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

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

EEDO Response:

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

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

EEDO Response:

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

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

EEDO Response:

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

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

Preamble:

EPCOR Electricity Distribution Ontario stated that it has enhanced its preventative maintenance practices in vegetation management and the tree trimming program has been set to a 3-year cycle.

Question(s):

a) What was the tree trimming cycle prior to be being set to a 3-year cycle.

EEDO Response:

In the past, tree trimming was completed during the winter months in areas on an as required basis.

b) Please provide EPCOR Electricity Distribution Ontario's vegetation management standards or practices.

EEDO Response:

EPCOR meets Ontario Electrical Safety Code Regulation 75-712 for vegetation management.

c) Does EPCOR Electricity Distribution Ontario survey its service area for vulnerable trees in danger of falling in its vegetation management program? If not, why?

EEDO Response:

EPCOR responds to any indication that a tree has become compromised and is at risk of falling on one of our lines as communicated by stakeholders, but it not possible to inspect all vegetation in the area with our resources outside of the three year vegetation management program.

2-Staff-33
Capital Project Prioritization
Ref: Distribution System Plan, page 61

Preamble:

EPCOR Electricity Distribution Ontario has provided a list of capital projects for the DSP period of 2023 to 2027 categorized by system access, system renewal, system service, and general plant.

Question(s):

a) How were projects prioritized?

EEDO Response:

Projects were prioritized following the risk ranking process as described in sections 5.3.1d of the DSP.

b) Please provide the project rankings for each project.

EEDO Response:

Please see attachment 2-Staff-33_DSP Risk Ranking Matrix_20220825

2-Staff-34
Engagement Survey
Ref: Distribution System Plan, page 10

Preamble:

EPCOR Electricity Distribution Ontario retained Stone Olafson to administer a customer engagement survey between November 18 to December 8, 2021. The survey aimed to canvass customer opinions on a number of key areas, including customer satisfaction and priorities related to customers' electricity service.

Question(s):

a) Please provide the engagement survey that was administered to customers.

EEDO Response

Please see attachment – 2-Staff-34 Attachment 1.

b) Please explain how the engagement survey results were used to prioritize capital investment projects.

EEDO Response:

The Customer survey engagement results helped to prioritize projects in two ways. One from a macro level, it confirmed where customer priorities are. These are discussed in the DSP from pages 9 to 14. This feedback helped to define the vision for a cost effective, responsive and reliable electricity serviced delivered through a resilient system that can continue to meet climate change impacts.

At a micro level, in the risk assessment part of the asset management process, as explained on page 28 and 29 of the DSP, customer alignment is part of the project ranking and weighting.

2-Staff-35
Fleet Vehicle Condition Assessment
Ref: Distribution System Plan, page 62

Preamble:

EPCOR Electricity Distribution Ontario developed its own fleet vehicle condition assessment in 2021. Eight vehicles were deemed to require replacement before the end of the DSP period.

Question(s):

a) One of the criteria that is assessed in each vehicle is engine hours. Please define engine hours.

EEDO Response:

An engine hour corresponds to the amount of hours the engine has been running both while driving and stationary idling.

b) How are engine hours captured?

EEDO Response:

Engine hours are captured by using a gauge or off of Geotab.

c) How was the assessment criteria/point evaluation developed?

EEDO Response:

This process was developed by information provided from a consultant who assisted in the development of the EPCOR's (Collus PowerStream) initial DSP filing 2019-2023 DSP.

d) Was the assessment criteria/point evaluation peer-reviewed?

EEDO Response:

Yes, this methodology was provided from another utility as an accepted assessment practice.

On page 255 of 353 of Exhibit 2 (fleet vehicle condition assessment), the CW14-04 small dump truck has a proposed replacement year of 2023. The assessment also states that the truck has 6 more years of service.

e) Please reconcile the year of replacement for CW14-04.

EEDO Response:

This should not read 6 more years of service as it will reach replacement condition in 2023.

f) Please provide a risk assessment if this truck replacement is deferred to 2024.

EEDO Response:

In late 2021,this truck was assessed at 28, fair condition. In 2022/2023, it will reach 29, replacement condition because it will have another year of life. In 2024, this vehicle will be at 30+ due to having another year of service, and may also pass another milestone in kilometers in use and engine hours.

2-Staff-36
Distribution System Plan – CDM Considerations
Ref: Exhibit 2 / Section 5.3.5
2021 CDM Guidelines, Chapter 3.1

Preamble:

EPCOR Electricity Distribution Ontario's DSP notes there are no planned rate-funded CDM activities in the planning period 2023-2027 to defer distribution infrastructure.

Question:

a) Please describe how EPCOR Electricity Distribution Ontario has addressed or plans to address the requirement in OEB's CDM Guidelines for distributors to "make reasonable efforts to incorporate consideration of CDM activities into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure."

EEDO Response:

EEDO reviewed a potential CDM initiative as a means to defer adding an additional feeder to one of our municipal stations. The proposed pilot CDM program's scope included the addition of smart thermostats and residential battery systems. The cost of the additional feeder was estimated at $57,675 due to its short length and use of existing infrastructure. The cost of the CDM program, aiming to achieve a reduction of 0.7 MWs when called upon, was deemed to be much higher than that (~$500K), and the collator didn't feel the economics would work. EEDO provides this as an example that it has considered and will continue to consider CDM or non-wires alternatives when it is looking at system capacity projects.

Exhibit 3 – Customer and Load Forecast

3-Staff-37
Residential Load forecast
Ref: Exhibit 3 / Tab 1 / Schedule 1 / page 7

Preamble:

A set of COVID/weather interaction variables were considered to capture the incremental consumption caused by people working from home and more generally staying at home due to lockdowns. These variables, "COVID HDD" and "COVID CDD" are equal to the relevant HDD and CDD variables from March 2020 to December 2021 and equal to 0 in all other months. The coefficients reflect incremental heating and cooling load from people working from home, public health lockdowns, and people generally staying at home.

Question(s):

a) Please include a scenario in which the COVID related variable take a value of 0 in 2022 and 2023 for the Residential rate class.

b) Please comment on how the issue of multicollinearity is being dealt with due to HDD, CDD and the COVID/HDD, COVID/CDD interaction variables?

EEDO Response:

a) The scenario is provided as 3-Staff-37 Attachment 1.

b) Multicollinearity between HDD/CDD and the COVID interaction HDD/CDD is not an issue because the variables have zero correlation in 98 out of 120 observations.

3-Staff-38
GS<50 kW Load forecast
Ref: Exhibit 3 / Tab 1 / Schedule 1 / page 17

Preamble:

Weather-normalized consumption and forecast values are calculated for the General Service < 50 kW class in Table 3.1-10 below, which incorporates the 10-year weather normal HDD and CDD, month days, binary shoulder variable, and COVID_AM. Forecast COVID-related values are adjusted downward by 50% in 2022 and 75% in 2023 to reflect the gradual declining impacts of COVID.

Question(s):

a) Please include a scenario in which the COVID related variable take a value of 0 in 2022 and 2023.

EEDO Response: The scenario is provided as 3-Staff-38 Attachment 1.

3-Staff-39
Load Growth
Ref: Load Forecast

Question(s):

a) How has EV penetration been factored into load growth expectation over the forecast period?

b) Has EPCOR Electricity Distribution Ontario developed a load forecast specifically for EV growth?

c) Has EPCOR considered the impact of Distributed Energy Resources (DERs) or other emerging technologies on its load forecast?

EEDO Response:

a) EV penetration has not been specifically factored into the load forecast as there isn't reliable data available to accurately project impacts.

b) No.

c) The load forecast does not specifically consider DERs or other emerging technologies.

3-Staff-40
Load Forecast Model – CDM adjustments
Ref: Exhibit 3 / Section 3.1.4
EB-2021-0020 Excel LRAMVA Workform, Tab 5 (2015-2027 LRAM)

Preamble:

EPCOR Electricity Distribution Ontario states that CDM data for each rate class used in the load forecast is from their last approved LRAMVA Workform under EB-2021-0020.

Questions:

a) Please explain the discrepancy between the CDM values per column D, E and F of the "CDM" tab of the Load Forecast Model as compared to Tab 5 of the last approved LRAMVA Workform for Residential, GS<50 kW and GS>50 kW customer classes. Please update the Load Forecast Model where applicable.

EEDO Response:

Please see 3-Staff-40 Attachment 1, which includes the "CDM" tab from the load forecast and Tab 3 (2015-2020 LRAM) from the EB-2021-0020 LRAMVA Workform. Figures in the "CDM" tab are linked to the relevant values from Tab 5 of the LRAMVA workform, demonstrating there are no discrepancies. A modified version of Tab 5 (2015-2020 LRAM) with values extended to 2023 is also included in the attachment.

Please note the GS>50 kW and Streetlight billing determinant has been changed from kW to kWh so all savings figures are kWh consumption and lost revenue calculations for these classes are overstated within the attachment.

3-Staff-41
Load Forecast Model – CDM adjustments
Ref: Exhibit 3 / Section 3.1.10
Excel LRAMVA Workform / Tab 5 (2015-2027 LRAM)
Load forecast model / CDM adjustment tab
Load forecast model / CDM tab
Load forecast model / Monthly data tab
Load forecast model / normalized annual summary
Load forecast model / summary tables

Preamble:

EPCOR Electricity Distribution Ontario describes how it has accounted for CDM in its load forecast by means of a manual adjustment formulated by external consultant, Elenchus (section 3.1.10). The CDM adjustments have been made to reflect impact of CDM activities that are expected to be implemented from 2021 to 2023. CDM activities have been forecasted based on EPCOR Electricity Distribution Ontario's share of consumption within the province using 2016-2020 OEB yearbooks and IESO's 2021-2024 CDM Framework.

Questions:

a) Please confirm 2023 forecast values in Table 3.1-28 of Exhibit 3 Section 3.1.10 should reflect the 2023 CDM adjusted forecast values per the Load forecast model under "Summary Tables" tab. Is a CDM adjustment also proposed for the 2022 Bridge Year? If so, please provide.

b) Please explain why CDM savings used for the historical impact of CDM in the load forecast ("CDM" tab) is not consistent with CDM savings used to dispose of LRAMVA balances (Tab 5 of LRAMVA Workform). For Example: 2020 in-year savings for GS>50 class shows 651kWh per the LRAMVA Workform, whereas the load forecast shows 298,133kWh.

c) How, if at all, is the impact of in-year 2021 energy savings from the 2021-2024 CDM Framework (Table 3.1-24) accounted for in the multivariate regression modelling approach described in section 3.1 (which utilized actual data from January 2012 to December 2021)?

d) Please clarify the rationale for EPCOR Electricity Distribution Ontario's use of a weighting factor of 0.5 for the contribution of 2021 in-year energy savings from the 2021-2024 CDM Framework to the proposed manual CDM adjustment to the 2023 Test Year (Table 3.1-24), and describe how this relates to the treatment of these savings within the multivariate regression modelling approach.

EEDO Response:

a) Not confirmed. Table 3.1-28 is erroneously a copy of Table 3.1-26, which includes actual 2017-2021 consumption figures and forecast 2022 and 2023 consumption **before** the CDM adjustment. The 2022 and 2023 forecasts with CDM adjustments are provided in the following two tables.

kWh	2022 Weather Normal Forecast	CDM Adjustment	2022 CDM Adjusted Forecast
Residential	137,569,214	68,670	137,500,544
GS < 50	44,762,094	270,812	44,491,281
GS > 50	130,541,505	725,008	129,816,497
Street Light	1,232,119		1,232,119
USL	396,233		396,233
Total	314,501,164	1,064,491	313,436,674

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

b) The savings figures included in the "CDM" tab of the load forecast are all kWh consumption savings figures as these figures are used to adjust class kWh consumption figures within the load forecast. The savings figures included in Tab 5 of the LRAMVA workform for the GS > 50 kW class are billed kW savings figures because this class is demand-billed. Savings are consistent when the "kW" in cell AG1155 of Tab 5 is changed to kWh. Please see the attachment provided with 3-Staff-40.

c) The impact of in-year 2021 CDM savings was not included in the multivariate model class, however, as half of these savings are included in the CDM adjustment then half should also be included within the dependant variable of the regressions. A version of the load forecast with half of 2021 CDM savings included in the Residential, GS<50 kW, and GS>50 kW dependant variables is provided as 3-Staff-41 Attachment 1. The load forecast filed with interrogatories includes this revision.

d) See part c).

Exhibit 4 – Operating Expenses

4-Staff-42
2022 Bridge Year Actual
Ref: Appendix 2-JC

Question(s):

a) Please update actual OM&A costs for 2022 bridge year in Appendix 2-JD format (and update other related tabs in Chapter 2 Appendices accordingly). Please specify for which months actual data has been used versus forecast.

EEDO Response:

To prepare the forecast, actual data through June 2022 has been used.

The following Appendix 2 tabs have been updated to reflect the updated 2022 OM&A.

Appendix 2-AB

Appendix 2-D

Appendix 2-JA

Appendix 2-JB

Appendix 2-JD

Appendix 2-L

Appendix 2-N

4-Staff-43
OM&A Costs from 2013 to 2023
Ref: Exhibit 4 / Tab 1 / Schedule 1 / pages 15-18

Preamble:

As stated in the application, the 2023 Test Year OM&A of $6,530k has increased from 2013 OEB-approved of $4,585k by $1,945k (42.4%). EPCOR Electricity Distribution Ontario explains (on page 17 of Exhibit 4) that the OM&A increase in the Administration and General category of $1,234k over the 10 years is primarily due to:

i. Inflation – EPCOR Electricity Distribution Ontario estimated that the costs attributable to inflation is approximately $285k.
ii. Shared Services - EPCOR Electricity Distribution Ontario notes that the total shared service costs in 2023 Test Year are $1,665k, and there are several offsetting costs which have been removed since 2013.

Question(s):

a) With respect to part ii above, please confirm the total estimated shared service costs for 2023 in amount of $1,665k are fully pertaining to the Administration and General portion in OM&A.

EEDO Response:

Confirmed

b) Please quantify the increase in Administration and General costs (2023 vs. 2013) attributable to shared service costs in part ii above. Please briefly discuss the calculation.

EEDO Response:

As shown in b) on page 17 Exhibit 4, increases in shared services of $1,665k were offset by movements in various other items shown in this bullet totaling $814k (CEO and HR positions - $278k, Controller position - $72k, Service Fee $132k, $94k costs charged from Collingwood PUSB, $22k costs from Torn of Collingwood, $216k building lease). The difference in these amounts is $851k.

c) Based on the answer to b) above, does the total dollar impact of inflation and shared service costs on the Administration and General cost increase reconcile to the $1,234k increase noted in the application? If not, please provide explanations.

EEDO Response:

The impact in b) above $851k plus the inflation estimate of $285k per a) on page 17 Exhibit 4 totals $1,136k. The remainder is due to various miscellaneous differences, likely differences in actual inflation versus the estimate in a) and other items.

4-Staff-44
COVID-19 Impacts on Capitalized Labour and Vehicle Costs in 2020
Ref: Exhibit 4 / Tab 1 / Schedule 1 / page 28

Preamble:

As stated in the application, the 2020 actual OM&A costs increased $517k compared to 2019 actuals. EPCOR Electricity Distribution Ontario explains that $304k of the increase was due to higher operations FTE as well as lower capitalized labour and vehicle costs due to lower time spent on capital projects primarily due to impacts of COVID-19 on operational crew availability and effectiveness, and adverse weather conditions.

Question(s):

a) Please provide more information about how COVID-19 impacted operational crew's availability and effectiveness in 2020 which resulted in lower capitalized labour and vehicle costs. Which months in 2020 were considered affected by the impacts of COVID-19 discussed in this question?

EEDO Response:

EEDO responded to the safety and operational risks posed by COVID-19 by quarantining and separating crews and staggering shift times for crews.

The months affected by COVID-19 in 2020 were from March through December.

b) Please quantify the amount of OM&A increase in 2020 pertaining to the COVID-19 impacts discussed in part a).

EEDO Response:

EEDO estimates that OM&A increased approximately $230k as a result of COVID-19 impacts discussed in part a).

4-Staff-45
Labour Allocation Due to Termination of Services to the Town of Collingwood
Ref: Exhibit 4 / Tab 1 / Schedule 1 / pages 27 and 40

Preamble:

As stated in the application, the Collus PowerStream 2013 OEB-approved FTEs of 22.92 included 9.35 FTEs (17 headcount) allocated from its affiliate company, Collus PowerStream Solutions Corporation (Collus Solutions) for providing services (utility activities) to Collus PowerStream. The remaining 7.65 FTEs of the 17 Collus Solutions employees were dedicated to providing services for non-utility activities for the Town of Collingwood. The Collus Solutions employees (who provided non-utility services to the Town of Collingwood) were moved to Collus PowerStream in mid-year 2016 and at the end of 2016, as the Town of Collingwood terminated the services provided by these employees (7.65 FTEs as estimated in 2013 proceeding).

EPCOR Electricity Distribution Ontario estimated that in 2016 and 2017, the labour costs increased by $203k and $150k respectively, as a result of increased FTE due to the termination of services to the Town of Collingwood.

Question(s):

a) Please confirm that the above noted incremental 7.65 FTEs were fully conducting utility activities after they were reallocated to Collus PowerStream. Please provide brief information about the major tasks and responsibilities assigned to the incremental resources on an ongoing basis, as well as the related department/position information.

EEDO Response:

Of the 7.65 FTE that were reallocated to Collus PowerStream, 2.7 of those 7.65 FTE remained working on non-utility billing activities for the Town of Collingwood as the remaining scope of services provided was limited to customer billing support as described on page 40 of Exhibit 4.

The 2.7 FTE for billing staff who continued to provide services have been excluded from the table below.

Department	Position	Tasks/Responsibilities
Executive	CEO	Provide Executive oversight for the utility

Executive	CFO	Provide Financial oversight for the utility including the financial and regulatory reporting, treasury, and preparation of financial planning and analysis
Executive	VP Operations	Provide Operational oversight for the utility
Management	HR Manager	Human resources function including labour relations, setting HR policy, monitoring compliance with labour law.
Management	Billing & Regulatory Manager	Oversight of customer service and regulatory function.
IT	Computer Systems & Network Technician	Implementation and maintenance of operational and information technology, oversight of cybersecurity.
IT	System Support Technician	Providing technical support to employees, assisting with hardware and software deployment.
GIS/Engineering	Engineering & Smart Grid facilitator	Preparing engineering and design of capital projects
GIS/Engineering	GIS Technician	Administration of the GIS system
Finance	Payroll/Benefits Coordinator/Finance Assistant	Administration of benefits and payroll and assistance with accounting bookkeeping.
Finance	Controller	Preparation of monthly financial and regulatory reporting.

b) Before the incremental FTEs were added to Collus PowerStream in 2016, how did Collus PowerStream use its existing resources to complete the portion of activities and tasks discussed in part a)?

EEDO Response:

When incremental FTE were added to Collus PowerStream in 2016-2017 as a result of the transfer from Collus Solutions, the additional FTEs were largely consumed in performing activities for the utility. EEDO was more fully completing capital work in-house (versus using external resources), was ramping up capital programs and completing more O&M activities in-house. This not only consumed additional Executive oversight time to implement these changes, it also used up additional GIS/Engineering and IT time to support these activities.

While there was some excess capacity, this pertained to small fractions of job positions and there was generally ample work found to use up the incremental time. And some of the capacity was used to reduce unpaid management overtime. Some attrition resulted, for example the CEO and Controller positions were vacated and not filled. This however did leave the utility somewhat short on resources and in need of some additional services when EPCOR acquired EEDO.

c) Please discuss how Collus PowerStream ensured efficiency in dealing with the reallocation of labour from Collus Solutions.

EEDO Response:

Collus PowerStream responded to the reallocation of labour by not backfilling positions as attrition occurred (CEO and Controller positions) and ensuring time spent on non-utility work was charged out appropriately. When EPCOR acquired Collus PowerStream, some embedded positions (as discussed in greater detail in 4.0-VECC-33) were moved to affiliates. In addition, where there was opportunity for embedded staff to use their expertise on affiliate work, their time was charged out and recovered from the affiliate (Regulatory, IT, and GIS).

4-Staff-46
Compensation and Short Term Incentive (STI) Program & Incentive Compensation Paid to Corporate Services Employees
Ref: Exhibit 4 / Tab 1 / Schedule 1 / pages 42, 53, 54, 84
Exhibit 4 / Tab 2 / Appendix A EPCOR Management & Salaried Compensation Administration Guidelines

Preamble:

EPCOR Electricity Distribution Ontario states that its compensation strategy and structure are based on EPCOR Utilities' compensation philosophy, which targets the "mid-market" or 50th percentile of a defined peer group for total employee compensation. EPCOR Electricity Distribution Ontario notes that EPCOR Utilities has defined peer group is comprised of energy, utility and pipeline organizations of similar size to EPCOR Utilities.

On page 53 of Exhibit 4, EPCOR Electricity Distribution Ontario states:

> EPCOR's STI program is designed to provide employees a competitive incentive plan that focuses on Business Unit ("BU") performance and the performance of the individual and includes a minor component related to EPCOR ("Corporate") financial performance. Target payout levels under the STI program are expressed as a percentage of salary in accordance with EPCOR's STI program.

EPCOR Electricity Distribution Ontario introduced its STI program (with the measures and related weightings) which is applicable to the non-represented employees. EPCOR

Electricity Distribution Ontario has included its target STI amount in 2023 Test Year revenue requirements.

As stated in bullet l. on page 84 of Exhibit 4, Incentive Compensation (paid to corporate services employees) is one of the categories of EPCOR Utilities' corporate costs that is allocated to EPCOR Electricity Distribution Ontario based on the corporate cost allocation. This bullet describes EPCOR Utilities' compensation for non-union and unionized staff, consisting of base compensation, employer-paid benefits, short-term incentive (STI) and medium-term incentive (MTI). The application states that the costs of any incentives are tracked separately.

Question(s):

a) Appendix A of Exhibit 4 indicates that EPCOR Utilities Board has established two main comparator groups in Canada that are used to determine EPCOR Utilities' competitive positioning. Please provide information about how often EPCOR Utilities Board normally conducts the review of the comparator groups. When was the last time this review was conducted? Please briefly discuss the major results and corresponding adjustments made to the compensation plan (if any) based on the most recent review.

EEDO Response:

As part of the terms of reference of the Human Resources and Compensation (HR&C) committee, established by the EPCOR Utilities Board, the Human Resources group is required to review the Comparator groups on a bi-annual basis with the HR&C committee. This includes a discussion with EPCOR's third party consultants, who review the comparators based on the principles established in the EPCOR's compensation philosophy and recommends any potential deletions or additions to the group.

This review was last completed in July 2022 and has led to an update to the compensation guidelines disclosed as of December 2021 which is the version included in Appendix A of the application. The only recommended changes to the policy relate to an update in geography to include comparator companies in Canada with operations in Ontario (previously it only included Western Canada) and for the US to include companies with operations in the South Central regions of the US (previously only included operations in the Lower Mountain regions of the US).

b) When did EPCOR Electricity Distribution Ontario start to implement the STI program discussed on pages 53 to 54 of Exhibit 4?

EEDO Response:

EEDO implemented the STI program when Collus PowerStream Corp was acquired by EPCOR in 2018.

c) Has there been any major change(s) to the STI program methodologies which influenced EPCOR Electricity Distribution Ontario's total STI cost by a material amount for a year? If yes, please briefly discuss the change(s) and the related outcomes in total STI costs.

EEDO Response:

There have been no material changes to the STI program methodologies since 2018.

d) In the Section 4.4.2 Shared Services and Corporate Cost Allocation, with respect to tables earlier than page 84, such as Table 4.4.2-2, on allocated costs from all affiliates, please confirm that any labour-related costs included in costs allocated to EPCOR Electricity Distribution Ontario from affiliates would consist of base compensation and employee benefits, and would not include costs for STIs and MTIs. In the alternative, please explain in detail.

EEDO Response:

For EOOMI, STI expense has been included in the labour-related costs. While EOOMI believes all incentive costs are a reasonable cost of the employee providing services to EOOMI, MTI costs have been excluded in order to reduce total costs allocated to service recipients by EEOMI.

For EWSI, STI and MTI are not included in the allocated costs.

For EDTI, STI and MTI are included in the allocated costs.

e) In Table 4.4.2-13, $56,441 is shown as the allocated incentive compensation for the 2023 Test Year. Bullet d. on page 85 states that this amount is the forecasted expense at Target. Please explain what "Incentive Compensation amounts at Target" means.

EEDO Response:

Incentive compensation has ranges of payout based on actual performance of the metrics used to calculate the incentive amount. For example, refer to the explanation of STI per pages 53 and 54 of Exhibit 4. The forecast of costs note in Table 4.4.2-13 includes incentive compensation at the Target level for each of the employees providing the services. Actual results for incentive metrics could be above or below Target based on actual results, but the forecast is set at the Target level.

4-Staff-47
OPEBs
Ref: Exhibit 4 / Tab 1 / Schedule 1 / page 58
Exhibit 4 / Tab 2 / Appendix B – Actuarial Report

Preamble:

In Table 4.4.1-7, OPEB OM&A amounts for 2019 to 2022 agree to the Total Defined Benefit Cost line in Appendix – Detailed Accounting Schedule of the Actuarial Report. Actuarial gains and losses included in Other Comprehensive Income are included in the Total Defined Benefit Cost. For 2019, there is an actuarial loss of $50,698, while there are no actuarial gains or losses for 2020 to 2022. Therefore, actuarial gains and losses are included in OPEB OM&A amounts presented in Table 4.4.1-7.

Actuarial gains and losses are included in Other Comprehensive Income and not OM&A, and therefore, should not be included in revenue requirement. There is no impact to EPCOR Distribution Ontario’s 2023 test year OM&A since there are no actuarial gains or losses forecasted for 2023.

Question(s):

a) Please confirm that EPCOR Electricity Distribution Ontario accounts for actuarial gains and losses for regulatory purposes in Other Comprehensive Income and not in OM&A. If not confirmed, please confirm that EPCOR Electricity Distribution Ontario will account for actuarial gains and losses in Other Comprehensive Income going forward.

EEDO Response:

EEDO confirms that actuarial gains/losses for regulatory purposes have been accounted for historically in Other Comprehensive Income (USoA 7010) and EEDO will continue to do so going forward.

The amounts included in Row 3 of Table 4.4.1-7 (OPEB in OM&A) incorrectly included the actuarial gain/loss in those amounts, specifically in the year 2013, 2016, and 2019.

4-Staff-48
Shared Services and Corporate Cost Allocation
Ref: Exhibit 4 / Tab 1 / Schedule 1 / section 4.2.2
Exhibit 4 / Tab 1 / Schedule 1 / pages 10, 17-30

Preamble:

EPCOR Electricity Distribution Ontario states that it obtains shared services from its affiliated companies EPCOR Water Services Inc. (EWSI), EPCOR Distribution and Transmission Inc. (EDTI), EPCOR Ontario Operations Management Inc. (EOOMI) and EPCOR Ontario Utilities Inc. (EOUI), as well as its parent EPCOR Utilities (for corporate shared services). Various types of services have been provided to EPCOR Electricity Distribution Ontario by the affiliated companies and EPCOR Utilities.

Page 10 of Exhibit 4 notes that in October 2018, EPCOR Utilities acquired Collus PowerStream and has worked to create efficiencies by implementing a shared service model that maximizes the value of services being provided. In the OM&A cost driver analysis provided in the application, the year-over-year OM&A increases pertaining to the increases in shared service costs are about:

- $186k in 2018
- $904k in 2019
- $458k in 2022 Bridge Year
- $115k in 2023 Test Year
- $226k in 2023 Test Year compared to 2013 actual

Question(s):

a) Please briefly discuss the processes that have been followed to establish, review and update the shared services structure (the list of shared services, associated amount of FTE and corresponding providers) for EPCOR Electricity Distribution Ontario. Please include the information related to the basis that the structure has been developed on and the parties involved in the relevant decision making.

EEDO Response:

EEDO reviews and evaluates all services required to prudently and safely run the utility on an ongoing basis, including affiliate shared services.

Since the acquisition of EEDO in 2018, senior management overseeing EEDO operations (located in EOOMI/EOUI) have evaluated services required to operate, maintain and expand the EEDO system. Based on this ongoing and periodic review, services are added or removed to ensure prudent and safe operation of the system.

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

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

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

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

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

EEDO Response:

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

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

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

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

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	Management	3	• General Manager • Senior Manager, Regulatory Affairs, • Senior Manager, Financial & Regulatory Reporting
2	Administration	6	• Admin Assistant • Accounting (1 of 2) (Administrator, Accounting) • IT Systems Specialist • Engineering Technolgoist • GIS Manager • Supervisor, Hydro Operations
3	Billing & Collecting	7	• CSR (4) • Billing Rep (2) • Accounting (1 of 2) (Customer Relations/Accounts Payable)
4	Linesperson	10	• PLT Lead Hand (2) • PLT (8)
5	Locator	2	Inspector/Locator (2)
6	Meter Technician	2	Meter Technician (2)
7	Stores Assistant	1	Stores Assistant

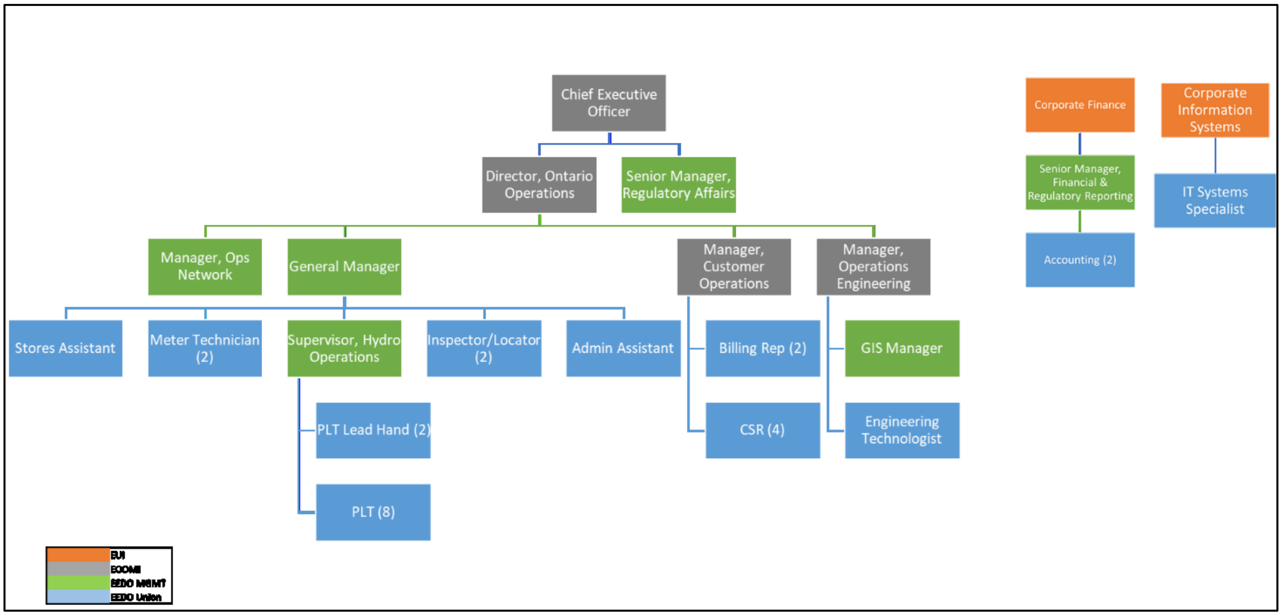
g) It's noted in Exhibit 4 that the following four positions are included in the shared services provided by EOOMI:

- Vice President, Ontario Region
- Director, Operations Ontario Region
- Manager, Customer Operations
- Manager, Operations Engineering

If these roles are included in the organizational structure chart, please indicate this information in a note or using color code. Please include a color code legend for the different colors used in the structure chart.

EEDO Response:

An updated org chart is included below.



EEDO notes that in addition to the four positions noted above, the Computer System & Network Technician noted in Exhibit 4 page 67 is also providing shared services from EOOMI to EEDO (Manager, Ops Network in org chart).

h) Please confirm if any shared service positions are counted in the total employee number of EPCOR Electricity Distribution Ontario (headcount).

EEDO Response:

There are no shared service positions included in the total employee headcount of EEDO

i) Please update the organizational structure chart (with number of employee information in each position box) to address the above questions.

EEDO Response:

An updated org chart is included the response to 4-Staff-49 g above.

4-Staff-50
Affiliate Companies and Organizational Chart

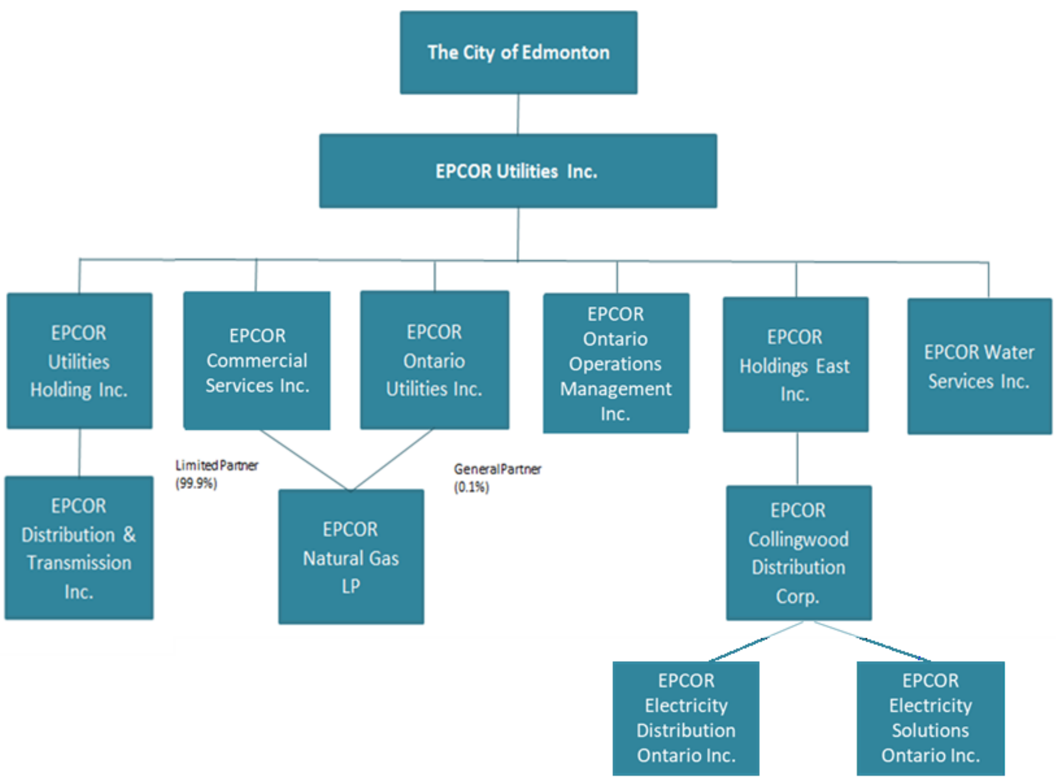
Ref: Exhibit 4 / Tab 1 / Schedule 1 / page 60
Exhibit 1 / Tab 1 / Schedule 1 / page 31, Figure 1.3-1

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.



4-Staff-51
Cost Recovery Basis for Shared Services Costs
Ref: Exhibit 4 / Tab 1 / Schedule 1 / page 60

Preamble:

EPCOR Electricity Distribution Ontario states that its shared services costs are determined on a cost recovery basis in accordance with the *Affiliate Relationships Code for Electricity Distributors and Transmitters* (ARC) and the services are delivered in accordance with a Service Level Agreement (SLA). The allocation of shared services is assessed regularly and adjusted as appropriate.

The ARC states that where a reasonably competitive market exists for a service, product, resource or use of asset, a utility shall pay no more than the market price when acquiring that service, product, resource or use of asset from an affiliate. The ARC defines that cost-based pricing shall only be applied where there is no competitive market for the service, product, resource or use of asset that a utility acquires from an affiliate or in the case of shared corporate services.

Question(s):

a) Please confirm if EPCOR Electricity Distribution Ontario has complied with the pricing mechanisms defined in the ARC in determining its shared services costs with its affiliate companies.

EEDO Response: Confirmed.

b) Please explain if the shared service costs are determined on a cost-based pricing, or determined with reference to the market price (following instructions defined in the ARC). If the costs are determined on a cost-based pricing, please provide reasons for this pricing mechanism which is not compliant with the ARC.

EEDO Response: Costs associated with shared corporate services are determined on a fully-allocated cost-based pricing in accordance with section 2.3.5.1 of the ARC. There is currently no market for the bundle of services received by EPCOR from its affiliate companies.

4-Staff-52
Shared Services Provided by EDTI
Ref: Exhibit 4 / Tab 1 / Schedule 1 / pages 64-65

Preamble:

It's noted that the shared service costs that EPCOR Electricity Distribution Ontario paid to EDTI increased from $25k in 2021 to $40k in 2022 Bridge Year. EPCOR Electricity Distribution Ontario states that the increase in costs is the result of adding the following two services in 2022:

- Monitoring SmartMap in addition to monitoring SCADA
- Developing switching orders for both planned and unplanned outages

Question(s):

a) Table 4.4.2-4 on page 64 appears to be cut off due to the page break, as there is no line 2 shown in the table. Please provide a complete version of Table 4.4.2-4.

EEDO Response:

Table 4.4.2-4 is reproduced below. Note that the table was complete, but there was an error in the row labelling. This has been updated in the table below.

Table 4.4.2-4

EDTI Shared Services Costs Allocated to EEDO

($)

		A	B	C	D	E
	Shared Service	**2019A**	**2020A**	**2021A**	**2022 Bridge Year**	**2023 Test Year**
1	System Controls	-	24,155	24,888	40,000	40,800
2	**Total**	**-**	**24,155**	**24,888**	**40,000**	**40,800**
3	Variance		24,155	733	15,112	800

b) Please explain why the service functionality being added in 2022 and 2023 for monitoring SmartMap in addition to SCADA and for developing switching orders for planned and unplanned outages is being charged solely as an ongoing operating expense. Are there not one-time costs associated with the increased functionality?

EEDO Response:

There are no one-time costs associated with the integration of SmartMap and SCADA into the control room. These applications already exist, the models developed and are available 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.

OT and SCADA Support: Time Spent Allocation (estimate) 50%, 2023 Test Year cost would be $80,275.

Operational Support: Time Spent Allocation (estimate) 40%, 2023 Test Year cost would be $73,358.

Management Oversight: Time Spent Allocation (estimate) 75% of 33% for the Vice President, Ontario Region position and 33% for the Director, Operations Ontario, 2023 Test Year cost would be $204,250.

c) Please discuss the rationale and necessity of implementing the cost allocation methodology change.

EEDO Response:

Please refer to the response in a) above.

d) On page 70 of Exhibit 4, it's stated that the percentages in the Table 4.4.2-6 will translate approximately into FTEs based on the number of positions providing the relevant services multiplied by the percentages shown in the table. Please explain how the equivalent FTEs are calculated with examples for some services. Please reconcile the calculated equivalent 2023 FTEs with the FTE figures included on pages 66 to 68 for each specific service.

EEDO Response:

The percentages show in Table 4.4.2-6 represent the amount of each Shared Service area being allocated to EEDO for the 2023 Test Year. The Shared Service cost pool build up is equal to the employee related costs for each of the individuals providing the services to EEDO and then the relevant % from Table 4.4.2-6 is applied to the cost pool to get EEDO's allocation. In this way, the % from Table 4.4.2-6 multiplied by the number of employees in the Shared Service area will result in an approximate FTE amount.

For example, for Human Resources, there is one Consultant Human Resources in EOOMI providing services. Per Table 4.4.2-6 the 2023 Test Year percent allocation of 48% will represent 48% of the costs of this employee and therefor results in an approximate 0.48 FTE being allocated to EEDO.

The FTE figures in pages 66 to 68 should match the column E percentages in Table 4.4.2-6. There were a few inadvertent errors in the number presented in pages 66 to 68. The approximate FTE numbers should have matched the amounts shown in Table 4.4.2-6.

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

EEDO Response:

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

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

EEDO Response:

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

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

EEDO Response:

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

h) On page 66 of Exhibit 4, the application states that the allocated resource of the VP Ontario Region and the Director Operations Ontario equates to 0.61 FTE in 2023 (in place of the former CEO position at Collus PowerStream). On page 90, it states that the VP Ontario Region and Director Ontario Operations is allocated at 0.7 FTE in 2023 in shared services. Please confirm the FTE equivalency of the VP Ontario Region and the Director Ontario Operations for 2023. Please confirm that this is used consistently in all applicable tables and calculations for shared services costs of this application. In the alternative, please explain and provide any necessary corrections.

EEDO Response:

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

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

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

Preamble:

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

Question(s):

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

EEDO Response:

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

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

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

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

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

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

EEDO Response:

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

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

EEDO Response:

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

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

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

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

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

EEDO Response:

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

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

EEDO Response:

Table 4.4.2-13

EUI Corporate Shared Services Costs Allocated to EEDO ($)

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

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

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

Preamble:

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

Question(s):

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

EEDO Response:

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

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

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

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

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

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

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

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

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

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

EEDO Response:

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

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

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

EEDO Response:

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

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

EEDO Response:

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

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

EEDO Response:

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

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

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

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

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

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

Exhibit 5 – Cost of Capital and Capital Structure

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

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.

Exhibit 6 – Revenue Requirement

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

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

EEDO Response:

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

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

Preamble:

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

EPCOR Electricity Distribution Ontario states that:

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

Question(s):

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

EEDO Response:

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

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

EEDO Response:

Confirmed.

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

EEDO Response:

Updated table 6.2-2 is provided below.

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

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

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

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

EEDO Response:

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

2023 – $112,666

2024 - $199,693

2025 - $575,342

2026 - $740,173

2027 - $860,919

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

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

Preamble:

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

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

Question(s):

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

EEDO Response:

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

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

EEDO Response:

As noted in the response to a), EEDO does not intend to take any accelerated CCA so there should not be any double counting between the two accounts.

6-Staff-60
PILs Workform
Ref: Exhibit 6 / Tab 2 / Appendix B – PILs Workform

In Schedule 8 of the PILs Workform for the bridge and test years, there are Adjustments and Transfers in column 5 of -$1,616,036 excluding CWIP for the bridge year, and -$994,401 for the test year. Please explain what these amounts represent and why adjustments to UCC are necessary.

EEDO Response:

The Transfers and adjustments for the Bridge Year and Test Year are summarized below:

Bridge Year

Class	Description	Contributions from Customers ($)	Vehicle Burden Adjustment ($)	Total ($)
8	General Office Equipment, Furniture, Fixtures		-2,443	-2,443
10	Motor Vehicles, Fleet		-29,711	-29,711
12	Computer Applications Software		-1,789	-1,789
47	Distribution System	-1,391,830	-173,234	-1,565,064
50	General Purpose Computer Hardware & Software		-9,184	-9,184
47	Smart Meters		-7,845	-7,845
Total	Bridge Year Total	-1,391,830	-224,206	-1,616,036

Note that updated 2022 Bridge Year forecast values for contributions is $1,253,036 and the Vehicle Burden Adjustment is $223,993. These adjustments are taken into consideration for the taxable income forecast in response to 6-Staff-58.

Test YearClass	Description	Contributions from Customers ($)	Vehicle Burden Adjustment ($)	Total ($)
8	General Office Equipment, Furniture, Fixtures			
10	Motor Vehicles, Fleet		-11,018	-11,018
12	Computer Applications Software		-30,096	-30,096
47	Distribution System	-730,672	-194,636	-925,308
50	General Purpose Computer Hardware & Software		-8,153	-8,153
47	Smart Meters		-19,826	-19,826
Total	Test Year Total	-730,672	-263,729	-994,401

Per the tables above, contributions from customers will reduce the tax basis of the asset class for which the contributions were made if a valid Income Tax Act Subsection 13(7.4) election is provided with the EEDO T2 tax return. This election functions to deduct contributions from taxable income and reduce the tax basis of the asset classes instead. EEDO's intention is to file the election on a go forward basis to reduce taxable income.

Vehicle burden adjustments represent internal fleet services charged to projects for accounting purposes that need to be removed from additions on the CCA schedule. The reduction in tax basis is made on a pro-rata basis based on additions made to each UCC class.

6-Staff-61
PILs Workform
Ref: Exhibit 6 / Tab 2 / Appendix B – PILs Workform
Chapter 2 Appendix 2-BA

Preamble:

In the PILs Workform, the following depreciation related amounts are added back to regulatory net income in tabs B1 and T1:

Additions to net income	**PILs Workform**	
	2023	**2022**

Amortization of tangible assets	$1,397,064	$1,282,677
Amortization of intangible assets	$119,207	$59,702
Right of use asset	$171,830	$171,830
Vehicle burden	$356,391	$302,982
Total depreciation added back	**$ 2,044,492**	**$1,817,191**

The following is a breakdown of depreciation expense in Chapter 2 Appendix 2-BA:

Depreciation	**Appendix 2-BA 2023**	**Appendix 2-BA 2022**
Tangible and intangible assets excluding finance lease, deferred revenues	$1,872,661	$1,645,360
Property under finance lease	$171,830	$171,830
Depreciation excluding deferred revenue	**$2,044,491**	**$1,817,190**
Amortization of deferred rev	-$204,069	- $172,924
Gross depreciation	**$1,840,422**	**$1,644,266**
Remove transportation depreciation	-$356,391	- $302,982
Net depreciation in revenue requirement*	**$1,484,031**	**$1,341,284**

*Amortization of deferred revenues is included in revenue requirement through other revenues

Question(s):

a) Please explain the methodology in determining the amount of depreciation to be added back to net income in the PILs Workform, and how it reconciles the depreciation expense in Appendix 2-BA. Please include a discussion on the treatment of amortization of deferred revenue and vehicle burden.

EEDO Response:

Total depreciation added back for B1 and T1 PILs work form agree to the Depreciation excluding deferred revenue per Appendix 2-BA. The amortization of deferred revenue is deducted from taxable income for both the B1 and T1 in the T1 PILs work form on Tab "B1 Sch1 Taxable Income Bridge" and Tab "T1 Sch 1 Taxable Income Test". This amount should not be taxable as it represents accounting amortization of contributions received.

The recovery of vehicle burden amounts are deducted from taxable income to the extent that they relate to vehicle fleet charges to capital projects. These deductions are included in for both the B1 and T1 in the T1 PILs work form on Tab “B1 Sch1 Taxable Income Bridge” and Tab “T1 Sch 1 Taxable Income Test”.

Exhibit 7 – Cost Allocation

7-Staff-62
Weighting Factors
Ref: Exhibit 7 / Tab 1 / Schedule 1 / pages 2-4

Preamble:

EPCOR Electricity Distribution Ontario states that "an analysis of accounts 5305 – 5340 was conducted." The meter reading weight for the meter type "Demand with IT and Interval Capability" is 0.38.

Question(s):

a) Please provide the analysis which supports the proposed weighting factors.

b) Please provide the derivation of the weighting factors for Meter Reading.

c) Please confirm that the costs used in part b) are the same costs that are recorded in account 5310.

EEDO Response:

a) EEDO's review of meter reading concluded there are no differences among the three types of AMI meters (AMI Meters, AMI Meters Commercial, and AMI Commercial with IT). For the Demand with IT and Interval Capability, EEDO relied on the weighting factor used in its last COS proceeding.

b) As described in part a), EEDO relied on the Demand with IT and Interval Capability weighting factor from its last COS proceeding. The weighting of the costs within account 5310 do not differ for the three types of AMI meters so derivations were not required and all three were assigned a weighing of 1.0.

c) Confirmed, though as noted in part b), a calculation of the costs within account 5310 was not required.

7-Staff-63
Meter Count
Ref: Cost Allocation Model / Sheet I7.1 Meter Capital / I7.2 Meter Reading

Preamble:

In the GS < 50 kW rate class, on sheet I7.1, 1,733 meters reads are identified as Smart Meters, while 100 are identified as demand with IT meters. On sheet I7.2, total meter unit count is 1733.

Question(s):

a) Please explain the apparent discrepancy for the GS < 50 rate class.

EEDO Response:

Tab I7.2 Meter Reading should include 100 demand meters for the GS<50 kW rate class, consistent with tab I7.1 Meter Capital and the total number of GS<50 kW customers (1,833) in tab I6.1 Revenue. This has been corrected in 7-Staff-63 Attachment 1 and in the cost allocation model filed with interrogatory responses.

7-Staff-64
Load Profiles
Ref: Exhibit 7 / Tab 1 / Schedule 1 / pages 5-10
Demand Data Model / Sheet Res
Cost Allocation Model / Sheet I8 Demand Data

Preamble:

EPCOR Electricity Distribution Ontario has provided a regression model for Residential and noted that “other classes and historic weather data has been removed to reduce the size of the model.” The included regression model was estimated based on 24840 observations (hourly data for the three years from 2019-2021). A single HDD or CDD value is used for each day.

The 1CP and 4CP values in the Demand Data model do not match the same values in the cost allocation model.

Question(s):

a) Please provide the regression output for all rate classes (comparable to the information found on the Res sheet, columns B through F).

b) As a scenario, please provide regression output that results from only using 2019 historic data.

c) For any rate classes that weren’t estimated using regression, please explain the methodology used to produce the 2023 load profiles.

d) Is hourly temperature data available for the Collingwood area? If so, please explain why daily temperature data was used.

e) Please explain the apparent inconsistency between the cost allocation model and the demand data model or revise.

EEDO Response:

a) The regression outputs are provided in 7-Staff-64 Attachment 1.

b) The regression outputs from using only 2019 data is provided in 7-Staff-64 Attachment 2.

c) The two rate classes that weren't estimated using a regression model are the Streetlight and USL rate classes, which are not weather sensitive. The USL profiles are based on average hourly consumption in each month in 2019, scaled so that the sum of 2023 hourly demand is equal to forecast 2023 USL consumption from the load forecast. The Streetlight profiles are based on a typical street lighting profile, also scaled to forecast 2023 consumption.

d) Hourly temperature data is generally available for the Collingwood area, however there is missing data in each year. Using hourly temperature data would add additional complexity to the weather normalization process within the demand data model.

e) The 1CP and 4CP demand data in the Cost Allocation model is inadvertently based on demands in months that are not the 1CP or 4CP months. The figures should include demands from the peak months in the 2023 forecast year, but a cell reference error caused the 1CP and 4CP to be based on the months with that were peak months in 2021. The data is corrected in the Cost Allocation model filed as 7-Staff-64 Attachment 3. Coincidently, the 12CP is the coincident peak allocator used in the Cost Allocation model so this correction does not have an impact on the results of the model.

Exhibit 8 – Rate Design

8-Staff-65
Fixed / Variable Charge
Ref: Exhibit 8 / Tab 1 / Schedule 1 / pages 2-3
Cost Allocation Model / Sheet O2 Fixed Charge|Floor|Ceiling

Preamble:

EPCOR Electricity Distribution Ontario states:

> The Street Light monthly service charge, after a revenue adjustment to bring the revenue to cost ratio to 120%, has a monthly service charge that is lower than the floor from the 'O2 Fixed Charge|Floor|Ceiling' tab". EEDO proposes to increase the monthly service charge to the minimum.

The proposed fixed charge for the street lighting rate class is $1.94.

Question(s):

a) Please confirm that the minimum system with peak load carrying capability (PLCC) for the street lighting rate class from the cost allocation model is $1.94, and that this is in fact the ceiling.

b) Please confirm that the Avoided Cost is $0.00, and that this is in fact the floor.

c) Is EPCOR Electricity Distribution Ontario's proposal therefore to reduce the fixed charge in the street lighting rate class to the ceiling?

d) As a scenario, please provide the fixed and variable charges that would result from maintain the existing proportions of 73.2% fixed, 26.8% variable.

Response:

a) Confirmed.

b) Confirmed.

c) Confirmed.

d) Maintaining the existing 73.2% fixed and 26.8% variable split would result in a $1.84 fixed charge and $7.6554 variable charge.

8-Staff-66
Low Voltage Service Rates
Ref: Exhibit 8 / Tab 1 / Schedule 1 / page 15

Preamble:

EPCOR Electricity Distribution Ontario has estimated the Low Voltage charge for the 2023 Test Year to be $1,031,829. It has calculated Low Voltage Rates by Rate Class using the 2021 actual costs as a basis for calculation, while removing the impact of rate riders.

Question(s):

a) Please provide the low voltage expense that would result if 2022 Hydro One rates excluding rate riders were applied to a 5-year average of 2017-2021 volumes

EEDO Response:

Using the five year average at 2022 rates, the low voltage expense would be $1,081,655.

Primary Metering Entity	Rate Name	Rate $	5 year average kW	Total
Creemore	Shared LV DS	$1.69	1,933	$39,172
Wasaga	Shared LV DS	$1.69	655	$13,280
Thornbury	Common ST Lines	$1.62	3,984	$77,486
Stayner	Common ST Lines	$1.62	45,529	$885,516
9 Wholesale Points	Fixed Charge	$612.97	9	$66,201
Total				$1,081,655

8-Staff-67
Loss Factors
Ref: Exhibit 8 / Tab 1 / Schedule 1 / page 18

Preamble:

The RRR values for 2.1.5.3 Supply indicate 307,339,771 kWh for Collus PowerStream in 2017 (reported 2018), and 315,450,702 kWh, 309,631,324 kWh, and 306,437,609 kWh for 2018-2020 for EPCOR Electricity Distribution Ontario for 2018-2020. Embedded Generation is additional.

The losses in the distribution system have been increasing every year from 2017 to 2021, including an increase from 1.0209 in 2019 to 1.0307 in 2020.

Question(s):

a) Please ensure that embedded generation is included in the power delivered to the distributor as it reflects part of the supply used in the delivery of power to customers.

EEDO Response:

Embedded generation has been added to the revised schedule App.2-R_Loss Factors accompanying this submission. There is no change to the total loss factor.

b) Please provide any insight EPCOR Power Distribution Ontario has into the cause of the increased losses from 2019 to 2020.

EEDO Response:

The cause of the losses may be attributable to changes in consumption patterns as a result of the COVID-19 pandemic (specifically higher residential usage which operates off of lower voltage transformers).

Exhibit 9 – Deferral and Variance Accounts

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

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

> EEDO proposes for the purposes of determining the amount to record in the RITDA for a given year that the taxable income (or losses) for the 2022 Bridge Year and any subsequent period will reduce (or increase) this loss carry-forward balance for regulatory purposes and in the year that the loss carry-forward balances is fully utilized. And for subsequent years, that amounts are added to the RITDA based on the taxable income for years once the loss carry-forward balance is fully utilized.
>
> EEDO proposes that for the purposes of determining the amount to record in the RITDA, the actual cash income taxes each year are calculated based on the tax rate in place at the time of this Application. This will ensure no double counting of a recovery between the RITDA and Account 1592 – PILS and Tax variances due to changes in legislation.

The draft accounting order in Appendix D states

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

Question(s):

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

EEDO Response:

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

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

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

EEDO Response:

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

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

EEDO Response:

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

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

EEDO Response:

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

9-Staff-69
GA Analysis Workform

Ref: GA Analysis Workform
GA Analysis Workform Instructions for 2023 Rates, dated May 27, 2022

Preamble:

Due to the timing of EPCOR Electricity Distribution Ontario's application filing, it does not appear that the 2023 version of the GA Analysis Workform was used.

Question(s):

a) The GA rates used in EPCOR Electricity Distribution Ontario's GA Analysis Workform appear to be different than the rates in the GA Analysis Workform for 2023 rate applications and the rates posted on the Independent Electricity System Operator website (which includes the 2021 GA recovery rates). The rates are as follows:

Table 9-1

	GA Rate Billed ($/kWh)		GA Actual Rate Paid ($/kWh)	
2021	**Per EPCOR**	**IESO Posted Rates**	**Per EPCOR**	**IESO Posted Rates**
January	0.13331	0.09092	0.13307	0.08798
February	0.16191	0.10485	0.12132	0.05751
March	0.12749	0.0842	0.14960	0.09668
April	0.14439	0.06969	0.17484	0.11589
May	0.16651	0.10531	0.16264	0.10675
June	0.1641	0.11352	0.14472	0.09216
July	0.11662	0.07612	0.12940	0.07918
August	0.14107	0.08734	0.09679	0.05107
September	0.09812	0.05519	0.14255	0.08234
October	0.14233	0.07402	0.11204	0.0584
November	0.1185	0.06342	0.11367	0.06012
December	0.10312	0.05443	0.11438	0.06515

Please explain the differences and update the GA Analysis Workform for the appropriate GA rates.

EEDO Response:

As EEDO submitted this application before the 2023 GA analysis workbook was available, the data had to be manually entered into an older template. During this process, the data source for the GA rates was incorrect. EEDO has filed an updated version of the GA Analysis workform accompanying these responses.

b) As noted in the GA Analysis Workform Instructions for 2023 Rates, a reconciling item for the Impacts of GA Deferral is optional depending on the materiality of the reconciling item. Please confirm that this reconciling item is not material for EPCOR Electricity Distribution Ontario. If not confirmed, please quantify the reconciling item.

EEDO Response:

This reconciling item is not material.

9-Staff-70
GA Analysis Workform
Ref: GA Analysis Workform
GA Analysis Workform Instructions for 2023 Rates, dated May 27, 2022

Preamble:

In the GA Analysis Workform, unbilled to actual revenue differences are identified as reconciling items (2a and 2b) and principal adjustments. In the calculation of the expected GA variance in the table under Note 4, unbilled consumption is used.

Per pages 10-11 of the GA Analysis Workform Instructions, the scenario where a reconciling item and principal adjustment is required for unbilled to actual revenue differences is when the expected GA balance is calculated based on actual consumption, and the GA balance in the general ledger excludes the unbilled to actual revenue true-up.

Question(s):

a) Please confirm that the unbilled consumption included in the table under Note 4 that was used to calculate the expected GA variance represents actual consumption. If not confirmed, please revise the reconciling items and principal adjustments according to the GA Analysis Workform Instructions.

EEDO Response:

Confirmed.

9-Staff-71
Account 1550 – LV Variance Account
Ref: DVA Continuity Schedule

In the DVA Continuity Schedule, the 2020 ending interest for Account 1550 – LV Variance Account was not carried into the 2021 opening interest, resulting in $0 2021 opening interest. Please revise the DVA Continuity Schedule to update the 2021 opening interest.

EEDO Response:

Referring to tab EEDO_DVA_Continuity_Schedule_20220608_2a. Continuity Schedule, a value of $23,181 has been included in the 2020 closing and 2021 opening interest amount. A screen capture is included below. EEDO does not believe this to be an error.

				2021									
Account Descriptions	Account Number	Interest Adjustments (1) during 2020	Closing Interest Amounts as of Dec-31-20	Opening Principal Amounts as of Jan-1-21	Transactions Debit / (Credit) during 2021	OEB-Approved Disposition during 2021	Principal Adjustments(1) during 2021	Closing Principal Balance as of Dec-31-21	Opening Interest Amounts as of Jan-1-21	Interest Jan-1 to Dec-31-21	OEB-Approved Disposition during 2021	Interest Adjustments (1) during 2021	Closing Interest Amounts as of Dec-31-21
Group 1 Accounts													
LV Variance Account	1550	$23,181	$23,181	$1,785,442	$1,148,400	$700,993		$2,232,849	$23,181	$10,499	$17,214		$16,466

9-Staff-72
Pole Attachment Account
Ref: Exhibit 9 / Tab 1 / Schedule 1 / pages 9, 11
Exhibit 6 / Tab 1 / Schedule 1 / page 14
Accounting Guidance on Wireline Pole Attachment Charges, July 20, 2018

Preamble:

In Table 9.1-8 of Exhibit 9, the pole attachment revenues under “Updated OEB Rates” appear to be different than that in the Account 4210 Pole Attachment Revenues in Table 6.3-2 of Exhibit 6. The amounts are as follows:

Pole Revenues	**2018***	**2019**	**2020**	**2021**	**2022**
Table 9.1-8	$62,738	$273,820	$279,179	$279,179	$219,181
Table 6.3-2	$36,167	$142,733	$136,505	$146,473	$143,707
Difference	$26,572	$131,087	$142,674	$132,706	$75,474

*2018 revenues from Table 6.3.-2 is on an annual basis, whereas revenues from Table 9.1-8 is for Sept. to Dec. 2018. The revenue for Table 6.3-2 has been divided by 4 to be comparable to revenues in Table 9.1-8.

Question(s):

a) Please explain the difference in revenues between Table 9.1-8 and Table 6.3-2.

EEDO response:

The revenues presented in Table 6.3-2 in account 4210 represents the pole attachment revenue recorded annually based on what was previously approved in EEDO’s existing rates. These balances include the regulatory impact of the Account 1508, Sub-account Pole Attachment Revenue variance which reduces what would ordinarily be the “Updated OEB Rates” revenue to what was previously approved in EEDO’s existing rates.

b) Please revise the balance in Account 1508, Sub-account Pole Attachment Revenue Variance as necessary, and provide the supporting calculation. If a revision is required, please ensure that the balance is calculated based on the difference in pole attachment rates multiplied by number of poles as per the OEB's accounting guidance referenced above (under footnote 1).

EEDO Response:

EEDO confirms it believes that the balance requested for disposition has been calculated in accordance with OEB accounting guidance. EEDO has provided a detailed calculation of the balance requested for disposition in the table below.

		2018 (4 months)	2019	2020	2021	2022
A	# of Full Poles	5898	5898	5898	5898	5898
B	Wireline rate per EB-2020-0288	$28.09	$43.63	$44.50	$44.50	$34.76
C	EEDO approved rate	$22.35	$22.35	$22.35	$22.35	$22.35
D	Full Pole difference per pole (B-C)	$5.74	$21.28	$22.15	$22.15	$12.41
E	# of Partial Poles	524	524	524	524	524
F	Wireline rate per EB-2020-0288 (divided by 2)	$14.05	$21.82	$22.25	$22.25	$17.38
G	EEDO approved rate (divided by 2)	$11.17	$11.17	$11.17	$11.17	$11.17
H	Partial Pole difference per pole (F-G)	$2.88	$10.65	$11.08	$11.08	$6.21
I	Full Pole Difference (A x D)	$11,285	$125,509	$130,641	$130,641	$73,194
J	Partial Pole difference (E x H)	$503	$5,578	$5,806	$5,806	$3,254
K	Annual Total (I + J)	$11,788	$131,087	$136,447	$136,447	$76,448
L	Cumulative	$11,788	$142,874	$279,321	$415,768	$492,216

9-Staff-73
Account 1508, Sub-account ICON F&G Meter Disposal
Ref: Exhibit 9 / Tab 1 / Schedule 1 / page 13
EB-2012-0116 Rate Order, October 24, 2013
DVA Continuity Schedule

Preamble:

EPCOR Electricity Distribution Ontario is requesting disposition of Account 1508, Sub-account ICON F&G Meter Disposal (i.e. Sub-account Stranded Meters Net Book Value) for $569,403, which includes $56,910 of carrying charges.

Question(s):

a) In the decision referenced above that discussed the establishment of the 1508 sub-account, the OEB noted that it was premature to determine whether the stranded FG meters will ultimately attract interest. Please explain EPCOR Electricity Distribution Ontario's rationale for including interest on the sub-account for disposition.

EEDO Response:

EEDO has revised the carrying charge amount it is requesting disposition for to $12,175 from $56,910. The $12,175 represents carrying charges from 2013 to 2022 for the portion of 2013 meters that were replaced and not included in 2013 approved rates ($92,250).

OEB Staff's submission on October 11, 2013 (EB-2012-0116) argued that carrying charges should not be recorded to the extent that the distributor is earning a return on the stranded asset in rates.

In the settlement agreement rate base was revised to remove the existing 2013 meters from ratebase and include the 2013 replacement meters in the same manner as other 2013 capital additions. Consequently, half of the 2013 replacement meter value would be included in 2013 approved rates.

Of the $512,493 in stranded costs for meter replacements in 2013 to 2015, $92,250 or half of the 2013 replacement meter cost is not earning a return in the 2013 approved rates.

For clarity, EEDO is requesting no recovery of carrying charges relating to the remaining principal balance of $420,243 which represents the other half of 2013 replacement NBV and 2014 and 2015 stranded assets.

The DVA continuity schedule has been updated with this information.

b) In tab 5 of the DVA Continuity Schedule, the 1508 sub-account balance is proposed to be allocated based on kWh. Please explain why this allocator was chosen and whether there is another more appropriate allocator (e.g. # of customers in affected rate classes). Please revise the DVA Continuity Schedule as necessary.

EEDO Response:

Tab 5. Allocation of balances on the DVA schedule has been updated with this information

9-Staff-74
Group 2 Accounts
Ref: Exhibit 9 / Tab 1 / Schedule 1 / pages 12-15
Accounting Order for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Customer Choice Initiative
Ontario Energy Board File No. EB-2020-0152, September 16, 2020
March 2015 Accounting Procedures Handbook Guidance #4
July 2012 Accounting Procedures Handbook Frequently Asked Questions #8

Preamble:

EPCOR Electricity Distribution Ontario is requesting disposition of Account 1508, Sub-account Customer Choice Initiative for $8,634, Account 1508, Sub-account Energy East Consultation Costs for $2,501 and Account 1508, Sub-account Late Payment Penalty for ($2,217).

For the Customer Choice Initiative and Energy East sub-accounts, the guidance documents referenced above note that materiality thresholds apply to the sub-accounts. For the Late Payment Penalty sub-account, the guidance document referenced above noted that the OEB did not approve a approve a variance account for to record any differences between the Late Penalty Payment cost and related revenue recovered in rates through the rate rider.

Question(s):

a) Please explain why EPCOR Electricity Distribution Ontario requesting the above noted sub-accounts for disposition, considering the guidance regarding the materiality of these accounts. Please revise the DVA Continuity Schedule to remove the balances of these sub-accounts.

EEDO Response:

The above noted amounts have been removed the from the revised DVA continuity schedule accompanying this submission.

9-Staff-75
Account 1509 - COVID-19
Ref: Exhibit 9 / Tab 1 / Schedule 1 / pages 9, 15
Exhibit 1 / Tab 1 / Schedule 1 / page 146 / Appendix B – 2021 Financial Statements
Report of the OEB: Regulatory Treatment of Impacts Arising from the COVID-19 Emergency (EB-2020-0133), June 17, 2021 (COVID-19 Report)
Guidance for Electricity Distributors with Forgone Revenues Due to Postponed Rate Implementation from COVID-19, August 6, 2020

Preamble:

EPCOR Electricity Distribution Ontario is requesting disposition of Account 1509 – Impacts Arising from the COVID-19 Emergency.

Page 39 of the COVID-19 Report indicated that Account 1509, Sub-account Forgone Revenues from Postponing Rate Implementation is not in scope for the COVID-19 consultation. Separate accounting guidance (as referenced above) was issued for this sub-account.

Note 5 of EPCOR Electricity Distribution Ontario's 2021 Audited Financial Statements state:

> …the Company has not experienced any significant impact of COVID-19 on its operations and financial results except for a decline in services to commercial customers mainly due to business closures resulting from government imposed restrictions, which has largely been offset by an increase in services to residential customers. Overall, the COVID -19 pandemic did not result in any material impact on the financial results of the Company for the years ended December 31, 2021 and 2020.

Per page 3 of the OEB's COVID-19 report referenced above, the OEB is expecting requests for disposition of Account 1509 to be filed only on an exceptional basis for costs not related to mandated government or OEB-initiated programs; and utilities should generally have been able to manage pandemic-related impacts within existing budgets.

Question(s):

a) Please separate out the Account 1509, Sub-account Forgone Revenues from Postponing Rate Implementation for ($17,475) from the other 1509 sub-accounts in the DVA Continuity Schedule as different guidance applies to this sub-account.

EEDO Response:

EEDO has revised its claim for this account to only include lost revenues as a result of waived interest charges. EEDO has revised the DVA schedule accompanying this submission to include a 50% recovery allocation:

	2020	2021	2022	100%	50%	Total Claim
Lost Revenues	43,464	43,464	43,464	43,464	21,732	21,732
Carrying Charges	177	425	1,076	1,076	320	320
Total	**43,641**	**43,889**	**44,540**	**44,540**	**22,052**	**22,052**

b) Given that the OEB's expectation is that utilities generally be able to manage pandemic-related impacts within existing budgets, and EPCOR Electricity Distribution

Ontario's financial statements that state that the COVID-19 pandemic did not result in a material impact on the financial results of the company, please explain why EPCOR Electricity Distribution Ontario is requesting disposition of the Account 1509, Sub-account Other Costs and Savings for incremental business operating costs of $29,221.

EEDO Response:

This balance has been removed from the disposition request.

c) Page 24 of the COVID-19 Report stated that the OEB will apply the criteria of causation, prudence and materiality to amounts in Account 1509. Furthermore, the COVID-19 Report indicated that materiality will be calculated based on the annual total of the amounts recorded in the Account, net of any offsetting cost savings recorded, and exclusive of any amounts recorded in the Exceptional Pool. Please discuss the materiality criteria on the annual amounts in the Account 1509, Sub-account Other Costs and Savings and revise the claim amount to remove annual amounts that do not meet the materiality criteria.

   i. Page 26 of the COVID-19 Report states that the onus will be on the utility to demonstrate that these savings have been identified and that all reasonable avenues of cost reduction have been explored and prudently acted upon. Please discuss how EPCOR Electricity Distribution Ontario has assessed and identified savings applicable to Account 1509.

   ii. Please update the DVA Continuity Schedule for any revisions in the claim amount.

   iii. Per page 48 of the COVID-19 Report, please ensure that amounts disposed are allocated based on the distribution revenue by rate class and the amount recovered is based on a monthly fixed charge, using the number of customers for each rate class as a denominator. Please note that in the 2023 DVA Continuity Schedule, a separate rate rider is established for disposition of Account 1509.

EEDO Response:

EEDO has revised its claim to only include amounts lost due to waived interest amounts, and at a 50% recovery and adjusted the allocation identified in point iii. above.

d) In Table 9.1-5, Account 1509 is proposed to be continued. On page 16 of Exhibit 9, it appears that EPCOR Electricity Distribution Ontario has not incurred any amounts for

Account 1509 in 2022. Please explain whether EPCOR Electricity Distribution Ontario anticipates further COVID-19 related costs to be recorded in Account 1509.

i. Per page 38 of the COVID-19 Report, Account 1509 will remain effective until the utility's subsequent rebasing application. Please explain why EPCOR Electricity Distribution Ontario is proposing that the account continue after rebasing.

EEDO Response:

The account was requested to remain open as the COVID-19 pandemic was a going concern there remained uncertainly regarding additional pandemic waves and impacts on operations. Based on more current information and provincial mandates, EEDO withdraws the request to keep the account open.

9-Staff-76
Account 1532 – Renewable Connection OM&A
Ref: Exhibit 9 / Tab 1 / Schedule 1 / page 19

Preamble:

EPCOR Electricity Distribution Ontario is requesting Account 1532 – Renewable Connection OM&A Deferral Account for $45,230 for disposition. The amount represents a prorated portion of the incremental cost built into the UtiliSmart rate (generation accounts as a % of all accounts) offset by the approved MicroFit charge.

Question(s):

a) Please explain what is meant by "incremental cost built into UtilSmart" and how the incremental cost is OM&A in nature and not capital.

EEDO Response:

EEDO's agreement with UtiliSmart includes a variable charge based on the number of active accounts, beyond a certain threshold. For each additional account added, costs of the service increased. UtiliSmart settlement manager is an online software as a service solution, leading to the treatment of costs as OM&A instead of capital.

9-Staff-77
Account 1557 – MIST Meters
Ref: Exhibit 9 / Tab 1 / Schedule 1 / page 21
DVA Continuity Schedule
Exhibit 1 / Tab 1 / Schedule 1 / page 146 / Appendix B – 2021 Financial

Statements

Preamble:

EPCOR Electricity Distribution Ontario is requesting Account 1557 – MIST Meters for $265,324 for disposition.

Question(s):

a) Please provide a breakdown of costs in the account by capital and OM&A.

	Capital	OM&A/Depreciation	Total
Principal	148,005	102,896	250,901
Carrying Charge	12,073	2,350	14,423
Total	160,078	105,246	265,324

b) Please confirm that the amount requested for disposition represents the revenue requirement impact of the meters.

i. If not confirmed, please explain why the revenue requirement impact was not requested for disposition.

EEDO Response:

The amount requested for disposition represents the incremental capital expenditure and operating costs associated with MIST meters. EEDO has excluded the MIST meters from its rate base which is why cost recovery is being sought on the incremental costs rather than the revenue requirement. If approved for disposition EEDO is not seeking continuance of this DVA.

ii. Please provide the revenue requirement calculation for the MIST meters.

EEDO Response:

EEDO has calculated the annual revenue requirement impact for MIST meters from 2017 to 2022 in the table below:

	2017	2018	2019	2020	2021	2022
Opening NBV	-	90,490	188,588	175,176	161,763	148,350
Additions	93,611	107,580	-	-	-	-
Depreciation	(3,120)	(9,482)	(13,413)	(13,413)	(13,413)	(13,413)
Closing NBV	90,490	188,588	175,176	161,763	148,350	134,938
Average NBV	45,245	139,539	181,882	168,469	155,057	141,644
WACC	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%
Return on ratebase	2,689	8,293	10,809	10,012	9,215	8,418
OM&A	1,403	8,150	9,813	9,961	10,192	10,192
Depreciation	3,120	9,482	13,413	13,413	13,413	13,413
Annual revenue requirement	**7,212**	**25,924**	**34,034**	**33,385**	**32,819**	**32,022**

iii. The annual principal balance has increase by approximately $10k annually, please explain why the principal balance has been increasing annually.

EEDO Response:

The balance has been increasing as a result of incremental operating costs associated with the MIST meters, these costs have been included in the deferral account and is being requested for disposition.

c) In EPCOR Electricity Distribution Ontario's 2021 financial statements, note 12 shows the MIST meter account for $201,191 and MIST Meter Capitalized for IFRS ($201,191). Please explain what the MIST Meter Capitalized for IFRS represents.

EEDO Response:

For financial statement reporting purposes the MIST meters were not allowed to be presented as a Regulatory Deferral balance per IFRS, the balance is re-classed from the Regulatory Deferral balance (under regulatory accounting) and presented in Property, Plant, and Equipment.

d) In tab 5 of the DVA Continuity Schedule, the Account 1557 balance is proposed to be allocated based on kWh. Please explain why this allocator was chosen and whether there is another more appropriate allocator (e.g. # of customers in affected rate classes). Please revise the DVA Continuity Schedule as necessary.

EEDO Response:

This has been adjusted to be fully allocated to GS>50kW customers as they are the only group impacted by this change.

9-Staff-78
Account 1568 LRAMVA
Ref: Excel LRAMVA Workform
Exhibit 9 / Section 9.3 Lost revenue adjustment mechanism variance account

Preamble:

2021 CDM Guidelines requires electricity distributors filing an application for 2023 rates to seek disposition of all outstanding LRAMVA balances related to previously established LRAMVA thresholds. EPCOR Electricity Distribution Ontario Inc. is seeking disposition of outstanding LRAMVA debit balance of $185,830 for 2021 and 2022 as part of their 2023 cost of service application.

Preamble response: EEDO has included a revised LRAMVA workform in response to this submission with the changes marked on tab 1-a.

Question(s):

a) Please confirm if EPCOR Electricity Distribution Ontario is seeking disposition of all outstanding LRAMVA balances and whether the LRAMVA would have a zero balance if disposition is approved.

EEDO Response: Confirmed

b) Please confirm that EPCOR Electricity Distribution Ontario is not at this time requesting to use the LRAMVA for any CDM activities for 2023 or beyond.

EEDO Response: Confirmed, subject to relevant government policy change

9-Staff-79
Account 1568 LRAMVA
Ref: Excel LRAMVA Workform / Tab 3 (Distribution Rates)

Preamble:

Tab 3 (Cell P40) under EB-2021-XXXX for rate year 2022, the rate rider for tax sharing under streetlighting shows $0.4031.

Question(s):

a) Please clarify EB-2021-XXXX is in reference to EB-2021-0020.

EEDO Response: Confirmed

b) Per Tariff of Rates and Charges under the Street Lighting Service Classification on page 20 of the Decision and Rate Order issued March 24, 2022 for EB-2021-0020, the rate rider for application of tax change (2022) – effective until April 30, 2023 shows $0.3236/kWh. Whereas the Low Voltage Service Rate shows $0.4031/kWh (which coincides with EPCOR's input in Tab 3, Cell P40). Please clarify the amount for 2022 Rate Rider for Tax Sharing under Streetlighting. If it differs from $0.4031, please update and file a revised LRAMVA Workform with the changes.

EEDO Response: Corrected in revised workform submission.

9-Staff-80
Account 1568 LRAMVA
Ref: Excel LRAMVA Workform / Tab 5 (2015-2027 LRAM) / 2015 Table 5-a
2017 Final Verified Results Report – LDC Savings Persistence Tab

Preamble:

In Table 5-a, savings from 2025 to 2027 could not be reconciled for the following programs:

- Coupon Initiative
- Bi-Annual Retailer Event Initiative
- Efficiency: Equipment Replacement Incentive Initiative
- Direct Install Lighting and Water Heating Initiative
- Process and Systems Upgrade Initiatives – Energy Manger Initiative
- Low Income Initiative
- Save on Energy Coupon Program
- Save on Energy Retrofit Program

Question(s):

a) Please provide the details and calculations (e.g., source documents or rationale for persistence factors) used to arrive at the 2025 to 2027 persisting energy savings.

EEDO Response:

Amounts have been reconciled to the 2017 Final Verified Results Report for all years in the revised workbook. In most cases, savings were combined with adjustments in the same line.

Corrected in revised workform submission. EEDO notes that the 2025-2027 persistence does not impact the proposed LRAMVA claim.

9-Staff-81
Account 1568 LRAMVA
Ref: Excel LRAMVA Workform / Tab 5 (2015-2027 LRAM) / 2016 Table 5-b
2017 Final Verified Results Report – LDC Savings Persistence Tab

Preamble:

In Table 5-b, electricity savings persisting from 2016 to 2025 could not be reconciled for the following programs:

<u>Loblaws Pilot</u>

Persisting savings from 2016 to 2025 reconciles with energy savings for the Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program. The Loblaws P4P Conservation Fund Pilot Program shows energy savings of $nil.

<u>Save on Energy Heating and Cooling Program</u>

Persisting savings from 2016 to 2025 per Tab 5 of the LRAMVA Workform reconciles with the 2017 Final Verified Report for Save on Energy Coupon Program except for verified savings from 2017 to 2025 with "######" input per LRAMVA Workform.

<u>Save on Energy New Construction Program</u>

Persisting savings from 2016 to 2025 reconciles with energy savings for the Save on Energy Heating and Cooling Program.

<u>Business Refrigeration Local Program</u>

Persisting savings from 2016 to 2025 reconciles with energy savings for the Save on Energy Energy Manager Program.

<u>First Nation Conservation Local Program</u>

Persisting savings from 2016 to 2025 reconciles with energy savings for the Business Refrigeration Incentives Local Program.

<u>Enersource Hydro Mississauga Inc. – Performance-based Conservation Pilot Program - Conservation Fund</u>

Persisting savings from 2016 to 2025 reconciles with energy savings for the Social Benchmarking Local Program.

Question(s):

a) With respect to Loblaws Pilot, please clarify if the energy savings reported under Loblaws Pilot in the LRAMVA Workform were for the Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program

    i. If so, please update the LRAMVA Workform accordingly.

    ii. If not, please provide the details and calculations used to arrive at the 2016 to 2025 persisting energy savings for Loblaws Pilot. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

b) With respect to Save on Energy Heating and Cooling Program, please clarify if the energy savings reported under Save on Energy Heating and Cooling Program in the LRAMVA Workform were for Save on Energy Coupon Program.

    i. If so, please confirm whether the “######” input for verified savings from 2017 to 2025 was a typo and should reflect the 2017 Final Verified Report for Save on Energy Coupon Program where persisting savings remained at 1,213,322 from 2017 to 2025 and update the LRAMVA form accordingly.

    ii. If not, please provide the details and calculations used to arrive at the 2016 to 2025 persisting energy savings for Save on Energy Heating and Cooling program. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

c) With respect to Save on Energy New Construction Program, please clarify if the energy savings reported under Save on Energy New Construction Program in the LRAMVA Workform were for the Save on Energy Heating and Cooling Program.

    i. If so, please update the LRAMVA form accordingly.

    ii. If not, please provide the details and calculations used to arrive at the 2016 to 2025 persisting energy savings for Save on Energy New Construction program. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

d) With respect to Business Refrigeration Local Program, please clarify if the energy savings reported under Business Refrigeration Local Program in the LRAMVA Workform were for the Save on Energy Energy Manager Program.

    i. If so, please update the LRAMVA form accordingly.

   ii. If not, please provide the details and calculations used to arrive at the 2016 to 2025 persisting energy savings for Business Refrigeration Local Program. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

e) With respect to First Nation Conservation Local Program, please clarify if the energy savings reported under First National Conservation Local Program in the LRAMVA Workform were for the Business Refrigeration Incentives Local Program.

   i. If so, please update the LRAMVA form accordingly.

   ii. If not, please provide the details and calculations used to arrive at the 2016 to 2025 persisting energy savings for First Nation Conservation Local Program. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

f) With respect to Enersource Hydro Mississauga Inc. – Performance-based Conservation Pilot Program - Conservation Fund, please clarify if the energy savings reported under Enersource Hydro Mississauga Inc. – Performance-based Conservation Pilot Program - Conservation Fund in the LRAMVA Workform were for the Social Benchmarking Local Program.

   i. If so, please update the LRAMVA form accordingly.

   ii. If not, please provide the details and calculations used to arrive at the 2016 to 2025 persisting energy savings for Enersource Hydro Mississauga Inc. – Performance-based Conservation Pilot Program - Conservation Fund. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

EEDO Response (applicable to questions a-f):

Errors occurred in the data when transposing the results from a previous years workform. Amounts for all years (2016-2028) have been revised to align with the 2017 Final Verified Results Report.

9-Staff-82
Account 1568 LRAMVA
Ref: Excel LRAMVA Workform / Tab 5 (2015-2027 LRAM) / 2017 Table 5-c

2017 Final Verified Results Report – LDC Savings Persistence Tab

Preamble:

In Table 5-c, the electricity savings persisting from 2017 to 2026 could not be reconciled for the following programs:

Save on Energy Coupon Program

Persisting savings (verified and true-up) from 2017 to 2026 per Tab 5 of the LRAMVA Workform could not be reconciled to the 2017 Final Verified Report. Only the 2017 energy savings true-up value of 1,679 per cell D486 could be reconciled to the Participation & Cost Report under the LDC Progress tab.

Save on Energy Heating and Cooling Program

Persisting savings (verified and true-up) from 2017 to 2026 per Tab 5 of the LRAMVA Workform was reconciled to the 2017 Final Verified Report with the exception of the following timelines:

- 2017 energy savings – True up (cell D489)
- 2018 energy savings – verified and true up (cell E488 & E489)
- 2019 energy savings – verified and true up (cell F488 & F489)
- 2020 energy savings – verified and true up (cell G488 & G489)
- 2021 energy savings – verified and true up (cell H488 & H489)
- 2022 energy savings – True up (cell I489)
- 2023 energy savings – True up (cell J489)
- 2024 energy savings – True up (cell K489)
- 2025 energy savings – True up (cell L489)
- 2026 energy savings – True up (cell M489)

Save on Energy Retrofit Program

Persisting savings from 2018 to 2026 per Tab 5 of the LRAMVA Workform could not be reconciled to the 2017 Final Verified Report. Only the 2017 verified energy savings could be reconciled to the Final Verified Report with immaterial differences and the 2017 true-up energy savings could be reconciled to the Participation & Cost Report under the LDC Progress tab.

Social Benchmarking Local Program

Persisting savings from 2017 to 2026 per Tab 5 of the LRAMVA Workform reconciles with the 2017 Final Verified Report energy savings for the Social Benchmarking Local Program with the exception of years 2018, 2019 and 2020 with inputs of "######" in the LRAMVA Workform.

Enersource Hydro Mississauga Inc. – Performance-based Conservation Pilot Program – Conservation Fund

Persisting savings from 2017 to 2026 per Tab 5 of the LRAMVA Workform reconciles with the 2017 Final Verified Report energy savings but for the Whole Home Pilot Program.

Question(s):

a) With regards to the Save on Energy Coupon Program, please provide the details and calculations used to arrive at the 2017 to 2026 persisting energy savings for the Save on Energy Coupon Program. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

b) With regards to the Save on Energy Heating and Cooling Program, please provide the details and calculations used to arrive at the persisting energy savings for the Save on Energy Heating and Cooling program for the aforementioned timelines. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

c) With respect to the Save on Energy Retrofit Program, please provide the details and calculations used to arrive at the persisting energy savings for the Save on Energy Retrofit Program from 2018 to 2026. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

d) With respect to the Social Benchmarking Local Program, please clarify the energy savings for 2018, 2019 and 2020. In your response, please provide the details and calculations used to arrive at the persisting energy savings for those years and confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

e) With respect to the Enersource Hydro Mississauga Inc. – Performance-based Conservation Pilot Program – Conservation Fund, please clarify the energy savings reported under Enersource Hydro Mississauga Inc. – Performance-based

Conservation Pilot Program – Conservation Fund per the LRAMVA Workform is for the Whole Home Pilot Program.

i. If so, please update the LRAMVA form accordingly.

ii. If not, please provide the details and calculations used to arrive at the 2017 to 2026 persisting energy savings for Enersource Hydro Mississauga Inc. – Performance-based Conservation Pilot Program - Conservation Fund. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

EEDO Response (applicable to questions a-e):

Errors occurred in the data when transposing the results from a previous years workform. Amounts for all years (2017-2029) have been revised to align with the 2017 Final Verified Results Report. The only deviation is that the 'Instant Discount Program' has been included as an 2017 adjustment to the 'Save on Energy Coupon Program' as there was not a dedicated section for that program.

9-Staff-83
Account 1568 LRAMVA
Ref: Excel LRAMVA Workform / Tab 5 (2015-2027 LRAM) / 2018 Table 5-d
2017 Final Verified Results Report – LDC Savings Persistence Tab

Preamble:

In Table 5-d, the electricity savings persisting from 2018 to 2027 could not be reconciled for the following programs:

<u>Save on Energy Home Assistance Program</u>

Energy Savings in 2018 per Tab 5 of the LRAMVA Workform were reconciled to the Participation & Cost Report under the LDC Progress tab. However, persisting savings from 2019 to 2027 could not be reconciled to any reports.

<u>Save on Energy Retrofit Program</u>

Energy Savings in 2018 per Tab 5 of the LRAMVA Workform were reconciled to the Participation & Cost Report under the LDC Progress tab. However, persisting savings from 2019 to 2027 could not be reconciled to any reports.

<u>Save on Energy Small Business Lighting Program</u>

Energy Savings in 2018 and 2020 per Tab 5 of the LRAMVA Workform were reconciled to the Participation & Cost Report under the LDC Progress tab. However, persisting savings in years 2019 and 2021 to 2027 could not be reconciled to any reports.

Question(s):

a) With regards to the Save on Energy Home Assistance Program, please provide the details and calculations used to arrive at the 2019 to 2027 persisting energy savings for the Save on Energy Home Assistance Program. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

b) With regards to the Save on Energy Retrofit Program, please provide the details and calculations used to arrive at the 2019 to 2027 persisting energy savings for the Save on Energy Retrofit Program. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

c) With regards to the Save on Energy Small Business Lighting Program, please provide the details and calculations used to arrive at the 2019 and 2021-2027 persisting energy savings for the Save on Energy Small Business Lighting Program. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

EEDO Response (applicable to questions a-c):

For all three programs, persistence savings was calculated using the 2017 Program Participation & Cost Report persistence methodology by program. This was submitted as part of EEDO's 2019 IRM filing (EB-2019-0025) and was further used in EEDO's 2020 filing.

2018 unverified results were multiplied by the "Persistence Methodology by Program" for years 1 through 6 (2018-2023). Values from year 6 were carried forward into future years.

Refer to: Participation and Cost Report – Collus PowerStream Corp – 2019 04 – Tab Reference Tables) as part of hearing EB-2020-0018.

9-Staff-84
Account 1568 LRAMVA
Ref: Excel LRAMVA Workform / Tab 5 (2015-2027 LRAM) / 2019 Table 5-e
2017 Final Verified Results Report – LDC Savings Persistence Tab

Preamble:

In Table 5-e, the electricity savings persisting from 2019 to 2028 could not be reconciled to the 2017 Final Verified Report (LDC Savings Persistence tab) or Participation & Cost report for the following programs:

- Save on Energy Heating and Cooling Program
- Save on Energy Retrofit Program
- Save on Energy Small Business Lighting Program
- Save on Energy Process & Systems Upgrades

Question(s):

a) Please provide the details and calculations used to arrive at the 2019 to 2028 persisting energy savings for the aforementioned programs. In your response, please confirm the source documentation of the claimed energy savings. If this documentation was not submitted as part of the initial application submission, please provide a copy.

EEDO Response:

Consistent with 9-Staff-83, persistence savings was calculated using the 2017 Program Participation & Cost Report persistence methodology by program. This was submitted as part of EEDO's 2019 IRM filing (EB-2019-0025) and was further used in EEDO's 2020 filing.

2019 unverified results were multiplied by the "Persistence Methodology by Program" for years 1 through 6 (2019-2024). Values from year 6 were carried forward into future years.

Refer to: Participation and Cost Report – Collus PowerStream Corp – 2019 04 – Tab Reference Tables) as part of hearing EB-2020-0018.

9-Staff-85
Account 1568 LRAMVA
Ref: Excel LRAMVA Workform / Tab 6 (Carrying Charges)
OEB's Prescribed Interest Rates Posted on the Website

Preamble:

Per Tab 6 of the LRAMVA Workform, the approved deferral & variance accounts interest rate is 1.02%. Since the LRAMVA Workform was filed, the OEB published its interest rate for Q3 and Q4 of 2022 at 2.20% on the OEB website.

Question(s):

a) Please update Tab 6 of the LRAMVA Workform to reflect the updated interest rate.

EEDO Response:

The updated interest rate has been included on the revised workform.

9-Staff-86
Account 1595 (2018)
Ref: Exhibit 9 / Tab 1 / Schedule 1 / page 23
Chapter 2 Filing Requirements for Electricity Distribution Rate Applications 2023 Rate Applications, pages 61, 62

EPCOR Electricity Distribution Ontario is requesting Account 1595 (2018) for $83,112. The associated rate riders expired April 30, 2020 and therefore, does not yet meet the Filing Requirement criteria for disposition. Please remove the sub-account for disposition in the DVA Continuity Schedule.

EEDO Response:

These amounts have been removed from EEDO_DVA_Continuity_Schedule_20220825 disposition.

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.

EPCOR

EB-2022-0028

EPCOR Electricity Distribution Ontario Inc.

Responses to School Energy Coalition Interrogatories

August 25, 2022

EB-2022-0028

EEDO RESPONSE TO INTERROGATORIES

OF THE

SCHOOL ENERGY COALITION

1-SEC-1
Please place on the record in this proceeding all evidence from EB-2017-0373/374. (Note: It is sufficient for the Applicant to simply agree to deem its evidence in that proceeding on the record for this proceeding and provide a link to the OEB's RESS, as opposed to re-filing all the material).

EEDO Response:

EPCOR's application, evidence and interrogatory responses can be referenced on the OEB's portal here:

https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber%3DEB-2017-0373&sortBy=recRegisteredOn-&pageSize=400

1-SEC-2
[Ex.1, p. 3, EB-2017-0373/0374 Decision and Order August 30, 2018] In the Decision and Order, it was noted that the premium to be paid by EPCOR for the purchase of Collus is $17.1M and the transaction costs were estimated to be $760k. The cost to provide the 1% decrease to residential customers would be $250k:

a) Please confirm the final amounts paid as a premium and for transaction costs.
b) Has EPCOR recovered these costs? If so, when was that completed?
c) Please confirm that the premium, transaction costs and the rate reduction were recovered through savings and efficiencies, and not from ratepayers.
d) Please itemize the savings that were used to recover these costs and explain the nature of these savings (e.g., whether one time, ongoing, sustainable).

EEDO Response:

a) EEDO confirms that the final purchase price premium and transaction costs were in-line with information provided in EB-2017-0373/0374. EPCOR does not track recovery of these costs and confirms that these costs have been borne by the shareholder.
b) No EPCOR has not recovered these costs and does not expect to do so going forward
c) EPCOR confirms that the purchase premium, transaction costs, and rate reduction were borne by the shareholder and not ratepayers/
d) There aren't any savings that would be used to recover these costs as this was an acquisition.

1-SEC-3

[Ex.1] Please provide all material provided to the EPCOR Utilities Inc.'s (EUI) Board of Directors regarding its approval of this application, and the underlying budgets.

EEDO Response:

EPCOR Utilities Inc's Board of Directors are not involved in the preparation of this application and were not provided materials regarding approval of this application.

1-SEC-4

[Ex.1] Please provide copies of all benchmarking studies, reports, and analyses that the Applicant has undertaken or participated in since the filing of its last rebasing application in 2013, that are not already included in the application.

EEDO Response:

EEDO is not aware of any additional information that is not referenced in this application.

1-SEC-5

[Ex.1] The Applicant has not identified any productivity initiatives it has undertaken over the last five years or that it plans to undertake in the test year and subsequent four years. Please provide details of all productivity and efficiency measures the Applicant has undertaken in the last five years and those planned for future years. Please quantify the savings and explain how the savings were calculated.

EEDO Response:

Since taking ownership of the LDC in 2018, EEDO has worked to identify areas of productivity opportunities as well as areas requiring additional investment in order to ensure stability of the LDC in the future.

Some examples include:

- EPCOR Ontario Shared services model – refer to 1-SEC-10. As EPCOR expands in the province, it is continuity building an Ontario based shared services model to improve productivity and expand knowledge.
- $270k Investment in a tension stringing machine and trailer used to allow additional work to be completed in-house without the need for a third party contractor, leading to more productive capital planning and execution.
- EEDO has also developed an improved capital planning program leading to increased oversight, better planning and more productive use of in-house resources
- EEDO has entered into multiple MSA agreements with vendors (i.e. tree trimming) to ensure availability of resources, cost certainty and savings

- EEDO is looking to enhance customer facing tools (i.e. green button and customer portal) to allow for more customer self-service and data usage, which will lead to more productive customer service through reduce phone calls and inquiries.

1-SEC-6
[Ex.1, Table 1.2-10] The table shows a 1% decrease in total billing from May 2022 to May 2023 for the typical customer in the GS > 50 kW class (250 kW and 86,000 kWh). Please confirm that the impact on Subtotal A only is a 40% increase from May 2022 to May 2023.

EEDO Response:

This statement was accurate based on our initial submission. (55% of the increase is the result of an increase in the distribution volumetric rate and 45% is due to changes in the LRAMVA rate rider along with the Group 2 DVA recover).

However, rate rider amounts have been revised based on IR's received and new bill impacts and rate riders have been calculated. Please refer to:

EEDO_DVA_Continuity_Schedule_20220825 and EEDO_2023 Tariff Schedule & Bill Impact Model_20220825 for updated values.

1-SEC-7
[Ex.1, p.19] Please provide a copy of the Business Plan referred to on page 19.

EEDO Response:

As per the filing requirements (2.1.2):

The distributor should provide its Business and/or its Strategic Plan. In the absence of a Business Plan or Strategic Plan, the distributor must provide key planning assumptions, a description of material factors (internal and external) that may affect the operation of the utility and major goals of the distributor in the test year and remaining years of the five-year term.

Section 1.2.10 has been submitted in the absence of a stand-alone business plan.

1-SEC-8
[Ex.1, p.21] Please provide a copy of EEDO's 2022 operational plan referred to on page 21, or point to where it is located in the evidence filed.

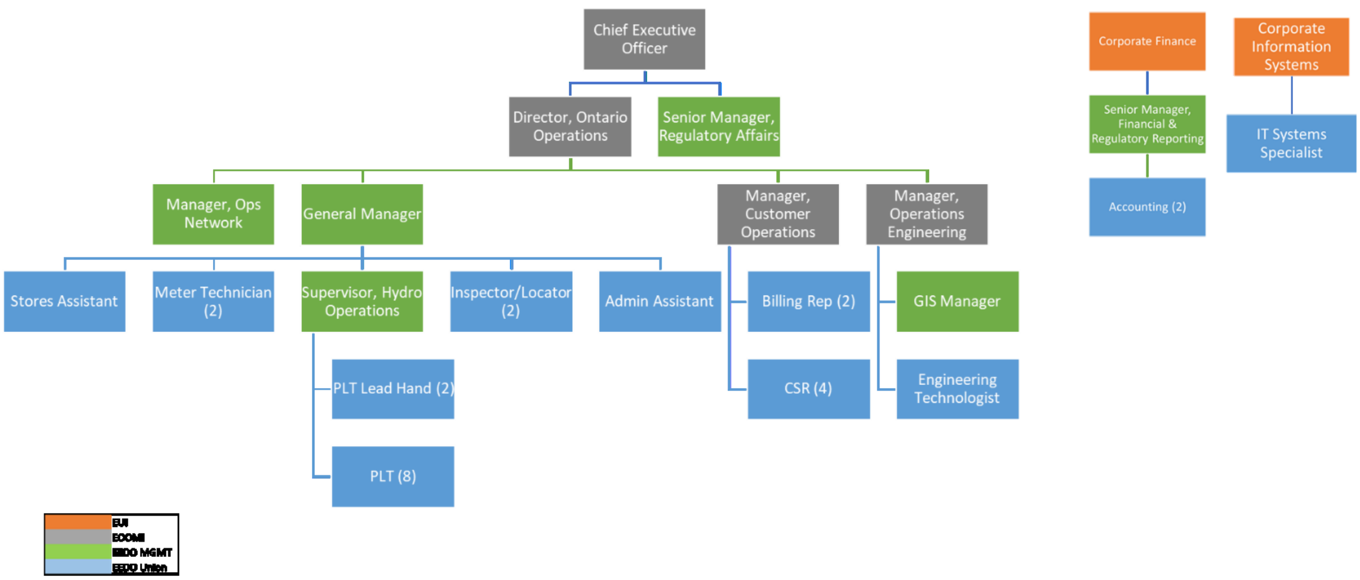
EEDO Response:

The operational plan can be found on Exhibit 1.2.10 pages 21-25.

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

investment in EV infrastructure into our operating areas.' Has EEDO included any capital spending in its forecasts to reflect this work?

EEDO Response:

EEDO has not included any capital spending in its forecasts to reflect this work. EPCOR's Ontario affiliate is acting as a delivery organization of federal grant funding towards EV infrastructure. While this has resulted in some third party investment into EV infrastructure in EEDO's operating area, this is not being undertaken by EEDO. The federal grant funding is being delivered to applicants across SW Ontario.

2-SEC-13

[Ex.2, pp. 24 & 40, Table 2.3.2] In comparing 2013 approved to actual capital, EEDO underspent by approx. 39%. Ex.2, p. 24 states that $500k of the reduced amount is due to two projects (the 10th Line – Poplar to Mountain Road Rebuild and Hurontario Street South in Collingwood) not being completed and carried over to 2014. Table 2.3.2 shows $28.5k in the WIP account for 2013. Please explain the discrepancy.

EEDO Response:

The $28.5k in the WIP account relates to the 10th Line project. The planned cost for this project was approximately $463k and represents the majority of the variance between actual capital to approved capital. The Hurontario project had outstanding work to be completed in the following year but the actual capital of $62k was put into service in 2013. The planned cost for the Hurontario project was $116k.

2-SEC-14

[Ex.2, p. 24] The application states, that 'An additional planned project on the 10th line was delayed completely due to being short staffed.':

a) What was the cost of this project?
b) What is the status of this project?

EEDO Response:

a) To clarify, the additional planned project was the 10th Line – Poplar to Mountain Road Rebuild which had a planned cost of $463k.

b) The project was completed in 2014

2-SEC-15

[Ex.2, p. 53; 2-AB] As part of the merger application, EB-2017-0373/0374 EPCOR provided a forecast of capital and Appendix 2-AB includes plan and actual $ for capital as follows:

$000	2019	2020	2021	2022	2023	2024

Status Quo Forecast EB-2017-0373/0374 Application p. 30	3,256	3,312	3,303	3,246	3,303	3,361
EPCOR Forecast EB-2017-0373/0374 Application p. 10	3,256	3,312	3,303	3,246	3,303	3,361
Appendix AB (net of contributed capital) Plan	3,299	3,670	3,743	3,457	4,296	4,491
Appendix AB (net of contributed capital) Actual	4,134	3,277	3,775	4,038	4,296	4,491

a) Please confirm the numbers in the above table and that they are all based on capital expenditures net of contributed capital. If not, please provide a similar table that is on a comparable basis.
b) What was the basis for the Plan numbers included in Appendix 2-AB?
c) Please explain the variances between:
   1) The EPCOR forecast and Plan
   2) Plan and Actual
d) When the EPCOR forecast was made for EB-2017-0373/0374 had the full assessment of the assets been done and the cost for any upgrades incorporated into the forecast?
   i. If not, then why not?
   ii. If yes, then please explain the statement, ‘ In addition there were increased contractor costs for substation maintenance primarily due to addressing issues identified upon acquisition to align safety and operating standards with EPCOR’s’ (Ex. 4-1-1, p.4).
e) How many months of actuals are included for the bridge year 2022?
f) How do 2022 year to date actuals compare to the Plan?
g) If there are material differences please update the appropriate tables in Appendix 2.

EEDO Response:

a) EEDO confirms that the numbers in the above table are net of contributed capital

b) The basis for the Plan numbers included in Appendix 2-AB are EEDO’s annual internal budget with figures in 2023 starting based on the DSP from this rate application.

c)

1. 2019 ($3,299 vs $3,256) - Increased spend on SCADA ($248k) as a result of new SCADA requirements and the Heritage Drive pole line rebuild ($210k) which was deferred from prior year, and budgeting a new pole storage bunker ($175k). These increases were partially offset by decreased spend on the Hamilton – St. Marie to Hurontario and Harben Court underground system renewal projects ($-161k) which was completed prior years to increase efficiency while other works were completed nearby. In addition scope and price changes were updated which reduced spend by $458k.

2. 2020 ($3,700 vs $3,312) –Increased spend on customer initiated work ($100k) and residential services ($99k) due to increased demand and pricing changes on various system renewal projects ($654k), partially offset by no longer requiring to complete two planned projects ($-465k) (Highway 26 to Brock Street and MS2 – Stayner St) as a result of the work being completed through other customer initiated work.

3. 2021 ($3,743 vs $3,303) – The increase is primarily due to pricing changes on various system renewal projects ($695k), the addition of the Arthur Street system renewal project ($220k) and misc underground rebuilds ($50k), and increased spending on SCADA ($48k), computer hardware ($32k), and a bucket truck ($75k). These increases were partially offset by no longer requiring to complete the Peel St – South of Hume planned projects ($-108k) as a result of the work being completed through other customer initiated work, deferral of two projects to 2022 ($-99k), and reduction in scope for the Mountain Road rebuild ($-503k).
4. 2022 ($3,457 vs $3,246) – The increase is primarily due to an increase in system access work net of contributions ($517k) due to an increase in customer initiated work, residential services, and ministry of transportation project. In addition, planned spending on general plant increased ($177k) due to increases in light duty vehicle replacements, and measurement & testing equipment. This was partially offset by a decrease in system renewal spending ($-537k) as a result of re-prioritizing renewal projects based on need and ability to complete the work.
5. 2023 ($4,296 vs $3,303) – The 2023 EPCOR Forecast was based on the prior year Forecast with inflation of 1.75% added. The significant increases is mostly due to System Service MS1 and MS2 substation upgrades ($689k) and the ArcPro and UN Migration project ($509k). System Access spending is higher ($418k) primarily due to increased spending on customer initiated work and residential services. This is partially offset by a decrease in System Renewal spending of ($-496k) as a new system renewal plan was developed for the 2023-2027 DSP.
6. 2024 ($4,491 vs $3,361) - The 2024 EPCOR Forecast was based on the 2022 year Forecast with inflation of 3.5% added. The significant increases is mostly due to System Service MS1 and MS2 substation upgrades ($724k). System Access spending is higher ($434k) primarily due to increased spending on customer initiated work and residential services. Vehicle spending is higher by ($497k) due to replacing a bucket truck versus light duty vehicles. This is partially offset by a decrease in System Renewal spending of ($-443k) as a new system renewal plan was developed for the 2023-2027 DSP.

ii.

1. 2019 ($4,134 vs $3,299) - Actual spending was higher relative to plan primarily due to spending on several system renewal capital projects carried forward from 2018 ($1,160k), a bucket truck that was planned to be purchased in 2018 ($334k), and higher spending on computer software/hardware as a result of integration ($204k). These increases were offset by a decrease in spending on planned system renewal projects from 2019 as a result of the spending on carried forward projects from 2018 ($-905k).

2. 2020 ($3,277 vs $3,670) – Actual spending was lower relative to plan primarily due to lower spending on 2020 system renewal projects ($-1,038k) partially offset by spending on carryover projects from prior years ($643k). COVID-19 risk mitigation measures impacted EEDO's ability to carry out capital projects as a result of lower line crew availability.
3. 2021 ($3,775 vs $3,743) – Spending was increased primarily due to higher System Access spending net of contributions as a result of higher customer initiated demand and residential services, this was partially offset by lower general plant spending for a bucket truck that was impacted by supply chain delays.
4. 2022 ($4,038 vs $3,457) – Spending is increased primarily due to forecasting receiving a bucket truck that was ordered in the prior year ($500k) and completing a project carried forward from 2021 ($279k), partially offset by decreases in system renewal projects as a result of scope changes and re-prioritizing projects ($-224k)
5. 2023 ($4,296 vs $4,296) – nil
6. 2024 ($4,491 vs $4,491) - nil

d) Yes, at the time the EPCOR forecast was developed, EPCOR had completed its due diligence and its forecast reflected the anticipated costs based on the diligence it completed.

EPCOR's due diligence included an assessment of distribution assets performed by a 3rd party consultant as well as internal field visits to Collus PowerStream.

EPCOR notes that there are inherent limitations to the due diligence process from the acquirer's perspective that limit the amount of information available to the acquirer, it is only when one has begun to operate the utiliy that the acquirer can fully assess the condition of the operations.

After acquisition EEDO's internal audit performed a reviewof the EEDO operations were conducted that identified additional issues that required remediation. To remediate these issues additional OM&A costs were incurred in 2020.

e) No months of actuals are included for the bridge year in 2022. Please see EEDO's response to 2-Staff-10 for an updated bridge year forecast.

f) 2022 year to date actuals are tracking closely compared to plan with one exception, we anticipate receiving a bucket truck that was ordered in 2021 in late 2022 which is approximately $0.5M and would put total net capital expenditures at around $4.0M for 2022.

g) Please see EEDO's response to 2-Staff-10

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							

EEDO Response:

The table below has been prepared to reconcile capex and in-service additions between 2-AB and 2-BA.

		2017	2018	2019	2020	2021	2022	2023
A	Capital Expenditures net of contributed capital	2,989,941	1,862,638	4,134,367	3,276,757	3,775,100	4,038,387	4,295,838
B	CWIP in previous year	142,712	292,992	386,726	1,500,442	1,608,381	2,739,427	976,671
C	CWIP in current year	292,992	386,726	1,500,442	1,608,381	2,739,427	976,671	976,671
D = A + B - C	In service additions in current year as per formula above	2,839,661	1,768,903	3,020,651	3,168,818	2,644,054	5,801,143	4,295,838
E	Change in tangible property (USoA 1990)	(55,907)	184,538	(75,605)	(26,330)	(118,065)	-	-
F	Property Under Finance Lease (USoA 2005)			1,676,316				
G	Change in CWIP	150,279	93,735	1,113,716	107,939	1,131,046	(1,762,756)	-
F = D + E + F + G	Sub-Total	2,934,034	2,047,176	5,735,078	3,250,427	3,657,035	4,038,387	4,295,838
	Additions Per 2-BA	2,934,034	2,047,176	5,735,078	3,250,427	3,657,035	4,038,387	4,295,838
	Variance	-	-	-	-	-	-	-

2-SEC-18

[Ex.2, 2-AB] EEDO has under forecasted its capital contributions by 100% ($472k vs $944k) between 2015 and 2021. Please explain the basis for EEDO's forecast of $731k for 2023 contributed capital and why it shouldn't be higher.

EEDO Response:

Customer driven capital is very challenging to forecast including the contributed amounts given the nature of the work. EEDO is contacted at different stages of the development process and major developments often take several years to materialize.

The level of contributions has been developed based on the level and type of work being performed while considering historical contribution amounts that align with the Distribution System Code's methodology for calculating contributions.

One of the reasons for the historical variance to forecast of gross capital contributions is that the gross customer driven capital has been larger than forecast; both contributions as well as the customer demanded gross capex have been under forecasted.

2-SEC-19
[Ex.2, DSP] In Exhibit 4-1-1, p. 13, EEDO states 'The capital budgets are prepared with the Distribution System Plan used as a starting point and adjustments made based on a review of project prioritization and resource availability.' Please provide a list of adjustments made to the capital budget from the DSP and reasons for the adjustments.

EEDO Response:

	2019	2020	2021	2022
EEDO 2019-2023 DSP	3,299	3,700	3,391	3,586
Capital Budget	3,299	3,700	3,743	3,457
Difference	0	0	352	-129

There were no adjustments made to the budget in 2019 and 2020 to the Distribution System Plan.

In 2021 the adjustments are as follows:

	2021	
Projects with Increased Spend	**2021 $**	**Reason**
SCADA	25	Increased SCADA requirements
Computer Hardware	32	
Bucket Truck	75	Increased cost estimates from vendors
Project Added to Budget		
Arthur Street rebuild	220	Project added to coordinate with municipality work timing
	352	

In 2022 the adjustments are as follows:

Re-prioritized projects	***2022 $***	
Osler Bluff Feeder Tie	-352	System renewal projects reviewed and re-prioritized based on need and ability to complete
Robinson Street - Hume to Collins	-349	
Elizabeth Street West	-233	
Collingwood St - Wellington St W to Louisa St	-248	

Wellington St W - Mill St to Collingwood St	-117	
St. Marie Street - Hume to Hamilton	100	
Project Added to Budget		
Substation Relay Replacements	137	Identified need not in DSP
Leasehold Improvements	18	Identified need not in DSP
Projects with revised costs		
Hurontario West- North & South of Third Street	58	
Campbell Street - Herrington Court to High Street	23	
Planned & Unplanned Pole Replacement Program	100	
Misc Rebuilds Underground	25	
SCADA	25	
Meters Interval	15	
Smart Meters	25	
Stores Equipment & Large Tools	11	
Measurement & Testing Equipment	58	Costs re-forecasted based on updated costing and work volume estimates.
Office Furniture & Equipment	-6	
Computer Hardware	-10	
Computer Software	-10	
Services - GS < 50	9	
Services - GS > 50	90	
Road Authority - Ministry of Transportation	300	
Customer Initiated - as demanded	805	
Contributions - road authority	-150	
Contributions - customer initiated	-570	
Vehicle (Two 1/2 Ton Pickup Truck $50k each)	117	Additional vehicle replacement need
Total	-129	

2-SEC-20

[Ex.2, DSP p.8] Under Regional Planning as part of the IESO SGB/M 2020 Scoping Assessment an IRRP & RIP is expected in 2022. Please provide an update on the status of this document and if it has been completed, does it affect the current DSP?

EEDO Response:

The IRRP was released in May 2022:

https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Parry-Sound-Muskoka

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

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

EEDO Response:

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

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

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

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

EEDO Response:

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

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

EEDO Response:

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

2-SEC-23
[Ex.2, DSP, Appendix 2-AB] Appendix 2-AB shows that for 2013 to 2021 EEDO underspent on System Renewal by $4.1M ($18.3M Plan versus $14.2M Actual). On page 20 of the DSP the average SAIFI of 0.83 and SAIDI of 1.55 are above the targets shown on page 18. Please explain the reasons for the under spending and how it has been a factor in EEDO not meeting its target.

EEDO Response:

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

2-SEC-24
[Ex.2, DPS pp. 51 & 57] The DSP lists one of 3 key drivers of its capital investment as 'planned system renewal spending to proactively replace plant at end of life in order to meet EEDO's commitment to maintain a safe and reliable supply of electricity to its customers.' (Emphasis added). Please reconcile this with the plan to proactively replace poles based on a health condition assessment, not simply by age (page 51).

EEDO Response:

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

2-SEC-25
[Ex.2, 2-BA, DSP p. 54] Based on information from 2-BA USoA 2055:

$000	2018	2019	2020	2021	2022	2023
Opening Balance	293	387	1,500	1,608	2,739	977
Additions	94	1,114	108	1,131	(1,763)	0
Closing Balance	387	1,500	1,608	2,739	977	977

From this table it appears that EEDO's WIP increased over the years 2017 to 2021, and as of the end of 2021 per 2-BA the balance in the WIP account was $2,739k. In the bridge year 2022, EEDO is forecasting that it intends to be able to complete and put into service $1,763k of that WIP work in addition to spending and putting in service $4,038k of assets:

a) Please provide an update on whether EEDO is on schedule to accomplish this.

b) If this forecast has changed, please provide an update.

c) On page 54 of the DSP EEDO states, re: System Renewal, 'The main driver of variance from plan to actual during this period was driven by carry over projects from previous years that were not completed … [i]n 2021, EEDO reset the capital budget and set it based on actual resource capacity rather than trying to include carry over projects'. Please explain what is meant by 'rather than include carry over projects'. How are carry over projects budgeted for?

EEDO Response:

a) EEDO remains on schedule to accomplish its planned capital for 2022 with one exception, a road authority project is forecast to carryover into 2023 as a result of delays in receiving information from Hydro One.

b) EEDO has provided an updated forecast for 2022 capital spending, please see EEDO's response to 2-Staff-10.

c) By resetting the planned projects for system renewal, EEDO evaluated the list of outstanding projects and prioritized them based on impact to service and reliability and these projects with the capacity to complete them. Carry over projects that were planned for prior years and were determined to be of lower priority would be deferred to future years and carry over projects that were determined to be of higher priority would be planned to be completed in the near term.

2-SEC-26

[Ex.2, DSP p. 91, 2-AA] EEDO has proposed migrating to ArcGIS Pro and replacing the underlying data model with Esri's Utility Network (UN) in 2023 at a cost of $509k. Is it feasible for EEDO to do this work over two years, i.e. migration to ArcGIS Pro in 2023 and replacing the underlying data model with UN in 2024?

EEDO Response:

EEDO and its support from EPCOR corporate IT applications group have worked with the GIS vendor to estimate the cost and effort involved in this transition. EEDO believes that it can deliver this project under these timelines by following a disciplined project management approach. EEDO will work closely with our corporate team who has experience in the delivery of similar and much larger projects of similar scope.

2-SEC-27

[Ex.2, DSP p. 97, 2-AA] In the 10 years between 2013 to 2022, EEDO has spent $0 on substation upgrades. The forecast for 2023 for Substation Upgrades is $689k. Please explain why EEDO has decided to start upgrading substations as of 2023 when no work was done for the last 10 years.

EEDO Response:

One of the primary drivers for the substation upgrades being planned in Stayner is to account for the load growth in the region, and to ensure that we have the ability to serve the Town of Stayner in an N-1 contingency scenario. At the same time, the project includes adding modern breakers with SCADA visibility on this station. Today, EEDO does not have SCADA visibility of the loading at the Stayner MSs. The MS is currently fused requiring a linesperson to travel to the station every time the fuse is blown, to refuse and energize. Adding modern breakers equipped with SCADA will provide EEDO with the ability to remotely operate the breakers at the MS and call for hold-offs as required from system control. This makes for a safer environment for our employees, and will improve reliability. These investments could have been made and justified for safety and reliability reasons over the past 10 years. EEDO is taking advantage of the opportunity while the transformers are being increased to better the operating design.

2-SEC-28

[Ex.2, DSP p. 124, Appendix A METSCO Fleet Vehicle Condition Assessment 2021, 2-AA] EEDO has forecasted to spend $2.1M over 2023 to 2027 for Vehicle Replacement and has spent $1.8M over the last five years. METSCO has provided an assessment of 18 vehicles for EEDO:

a) Did METSCO do a condition assessment on all vehicles within EEDO's fleet?

EEDO Response:

This assessment was not performed by METSCO, but was performed by EPCOR's operations leadership. The assessment was completed on the entire fleet and all assessments were included in the DSP.

b) If not, please provide a complete listing of all vehicles within the fleet, including year of acquisition, EEDO's assessment score and planned year for replacement.

EEDO Response:

All fleet assessments were provided in the DSP appendix.

c) Please update the table below to show if any of CW16-11, CW31-14 or CW32-14, which had a 'to be replaced' assessment, have been replaced.

EEDO Response:

CW 16-11, CW31-14 and CW32-14 are replaced or have been replaced in 2022.

d) If they have not been replaced, please explain.

Vehicle	METSCO Assessment Score	METSCO year of assessment	Plan for Replacement
CW11-15	33	2025	2025
CW12-19	18	End of DSP	
CW13-17	29	2026	2026
CW14-04	29	2023	2023
CW15-14	27	End of DSP	
CW16-11	33	2021	2022
CW18-15	30	2021	?
CW22-11	24	End of DSP	
CW29-18	32	2025	2025
CW30-10	29	2027	2027
CW31-14	35	2021	2022
CW32-14	30	2021	2022
CW33-12	34	2024	2024
CW34-19	35	2026	2026
CW36-19	19	End of DSP	
CW37-17	30	2023	2023
CW39-19	19	End of DSP	
CW40-18	16	End of DSP	

2-SEC-29
[Ex.2, 2-D] Appendix 2-D explains the changes in overhead capitalized as follows "Change in capitalized overhead policy on EPCOR Acquisition, for the increase in capitalized burden, administration and other general overhead costs.":

a) Please provide details on how the EPCOR capitalized overhead policy is different than that used before the acquisition.

EEDO Response:

As allowable under IFRS, costs that are directly attributable to the acquisition or construction of the PP&E asset are included in the capital overhead cost pool. This may include costs related to management oversight, operations management, accounting, legal, human resources, information systems, marketing, purchasing, office management as well as certain departmental OM&A costs.

b) If EEDO's approved capital is less than requested, what would be the effect on EEDO's OM&A?

EEDO Response:

To the extent that costs underpinning the requested capital include internal staff costs, the effect would be an increase in OM&A for related salary, burden, and capitalized overhead.

3-SEC-30
[Ex.3, Table 3.1-3] Is the Economic Forecast information provided for Ontario or for a narrower area more specific to the EEDO service areas?

EEDO Response:

The Economic Forecast information is for Ontario. Elenchus, EPCOR's load forecast consultant, is not aware of timely and publicly available third-party economic forecasts for the EEDO service area.

3-SEC-31
[Ex.3, Table 3.1-28] Table 3.1-28 Proposed CDM Adjustments appears to be a duplicate of Table 3.1-26. Please provide the correct version of the table.

EEDO Response:

Confirmed. The correct table is provided below.

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

4-SEC-32
[Ex.4, 2-JA] As part of the merger application EB-2017-0373/0374, EPCOR provided a forecast of OM&A and Appendix 2-JA includes actual $ for OM&A as follows:

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

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

EEDO Response:

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

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

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

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

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

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

EEDO Response:

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

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

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

4-SEC-33

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

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

EEDO Response:

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

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

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

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

EEDO Response:

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

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

4-SEC-34

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

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

EEDO Response:

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

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

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

EEDO Response:

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

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

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

4-SEC-35

[Ex.4, pp. 17 & 89] The application states on page 17 that 'EEDO's lease with the Town of Collingwood has been included as a capital lease and amortization of the Lease Asset is included in USofA account 6045'. Page 89 states, 'The 2013 Actual Collingwood Public Utilities Service Board includes $216,000 for building charges. When EEDO was acquired by EPCOR in October 2018, the Town of Collingwood entered into a new lease agreement with EEDO. This lease is now treated as a Right of Use Asset and included in rate base.':

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

EEDO Response

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

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

4-SEC-36

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

EEDO Response:

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

As described on page 74 of Exhibit 4, EUI is the ultimate parent company of EEDO. EUI provides Corporate Shared Services to all of EPCOR's operations.

EWSI is an affiliate of EEDO which provides regulated water, wastewater and drainage services to customers in Edmonton.

EDTI is an affiliate of EEDO which provides regulated electricity distribution and transmission services to customers in Edmonton.

4-SEC-37

[Ex.4, p. 71 &Table 4.4.2-7] Please explain why the customers of EEDO should be responsible for the increases shown on the table between 2021 and 2023, which are a result of 'various changes in the businesses/operations which EOUI/EOOMI were servicing' and not directly benefitting customers of EEDO?

EEDO Response:

All of the services noted on page 71 are direct services provided to EEDO by EOOMI and do directly benefit the customers of EEDO. Services provided by EOOMI are required for prudent, safe and reliable operations of the utility. HR support for EEDO employees, HSE support for EEDO employees and ensuring safe operations, Customer Service for EEDO's customers, OT and SCADA support for monitoring EEDO's operations, Operational Support to successfully implement and manage EEDO's capital program and Management Oversight of EEDO's operations are all necessary to build, operate and maintain EEDOs utility system.

The changes in costs from 2021 to 2023 are based on adding new services or enhancing existing services, moving embedded costs to a shared service model for cost efficiency and moving to a new cost allocation methodology. Also see response to 4-Staff-53 for further information on the change to the new cost allocation methodology.

4-SEC-38

[Ex.4, Table 4.4.2-9] Please explain how the services provided by EUI in the areas of Supply Chain Management, HR, Public & Government Affairs and Health, Safety & Environment are different from those same services provided by EWSI and EOOMI/EOUI.

EEDO Response:

HR and HSE services provided by EOOMI are discussed on page 66 of Exhibit 4 and these include on-the-ground HR and HSE support provided directly to EEDO. HR and HSE Services provided by EUI are described in b. on page 82 and 83 of Exhibit 4. These services include supporting the work performed by EOOMI, as well as providing overall governance and oversight of the HR and HSE function across all of EPCOR's operations. EUI HR also sets applicable policies, administration and management of the shared Human Resources and Information System and providing payroll functions to all EPCOR's Canadian operations. EUI

HSE also provides ongoing implementation of HSE requirement, report and program administration.

Supply Chain Management services provided by EWSI are described on page 62 of Exhibit 4 and primarily related to historical costs to assist EEDO in setting up EEDO's inventory in the Oracle Inventory system and related training costs to assist EEDO staff to learn the system. The insignificant ongoing costs for the 2023 Test Year are for one-off support which EEDO staff may require related to purchasing or strategic sourcing of goods and services. Supply chain services provided by EUI are described on page 82 of Exhibit 4 and relate to overall governance and oversight of the Supply Chain function as well as providing supply chain services to EUI's Corporate Services departments.

Public and Government Affairs services provided by EWSI are discussed on page 63 of Exhibit 4 and primarily relate to direct services provided to EEDO for internal and external communications for EEDO stakeholder and public consultation assistance for EEDO. Public and Government Affairs services provided by EUI are described on page 83 of Exhibit 4 provides oversight and governance of all P&GA activities across EPCOR.

4-SEC-39

[Ex.4, Table 4.4.2-1] Please add a line to Table 4.4.2-1 estimating the savings in each year as a result of EEDO no longer receiving Shared Services from Collus PowerStream Solutions Corp, or doing the service internally and indicate what those savings are a result , e.g cost of procurement services or HR.

EEDO Response:

As noted in 4-SEC-34 above, EEDO was no longer receiving shared services from Collus PowerStream Solutions Corp. by 2016.

Costs which EEDO was able to save form using Corporate Shared Services and Affiliate Shared Services include:

1. The following FTE positions were removed from EEDO since 2018 and moving to the Corporate Shared Services and Affiliate Shared Services model:
    a. Manager, HR (1 FTE)
    b. Manager, Ops Network (1 FTE)
    c. Manager, Billing (0.5 FTE)
    d. Manager, Hydro Services (1 FTE)
2. EEDO has been able to achieve various cost savings in acquiring required services for the safe and reliable operations of the utility, through receiving affiliate shared services instead of having to employee full FTEs. Please refer to the response to 1-SEC-10.

4-SEC-40

[Ex.4, p.53] Please provide the non-financial performance measures and related targets that make up the Short Term Incentive Program.

EEDO Response:

The non-financial performance measures for the 2022 year are as follows:

a) Customer Service - Call Answer performance

The OEB measures LDC performance as it relates to call answer on time %. Calls shall be answered within 30 seconds to meet this performance criteria.

Target = 82% across Ontario

b) Customer Service – ENGLP Southern Bruce customers connected

Target = Increasing customers by 1,750

c) Operational Efficiency – Committed Growth Investment

Based on the amount of EPCOR's investment in new growth capital pursuant to an actual signed agreement for Commercial Services.

Target = $80 million

d) Operational Efficiency – Ontario Cost per customer

The OEB measures Local Distribution Company (LDC) performance as it relates to cost per customer. This measure is reported in the annual Reporting and Record keeping Requirements (RRR) submission to the OEB, which is publicly released on a LDC dashboard and comparable to other LDCs.

Target = $284 in controllable cost per customer

e) Safety – EPCOR Aggregate All-Injury-Frequency

$$\text{AIF} = \frac{(\text{\# of disabling injuries} + \text{\# of medical aid injuries}) * 200{,}000}{\text{exposure hours (hours worked)}}$$

Target AIF = 1.15

f) Safety – Workplace Inspections & Observations

Workplace Inspections focus on hazardous conditions, unsafe actions or work methods and environmental aspects at the workplace. They help maintain safe working conditions and identify any potential hazards that arise in the workplace.

Workplace Observations focus on what people do in the workplace with respect to both safe and hazardous behaviours. They provide a direct way to correct at-risk behaviours, recognize safe work performance, and ensure that safety is prioritized and implemented across our organization.

Target = 202 total inspections or observations

4-SEC-41
[Ex 4, p. 94, Appendix 2-M] With respect to Regulatory Costs:

a) Please confirm the amounts that were included in the approved revenue requirement for 2013 were $112,206 for on-going regulatory costs and one-time costs of 1/5 of $254,395 = $112,206 + $50,879 = $163,085.

EEDO Response: Confirmed

b) Please confirm that EEDO had recovered its one-time costs of $254,395 by the end of 2017.

EEDO Response:

EEDO's actual one-time costs associated with the 2013 application was $346,356 as noted in Appendix 2-M; these were not fully recovered by the end of 2017.

4-SEC-42
[Ex.4, 2-JD] Please explain the significant jump in USoA 5605 Executive Salaries and Expenses from $208k in 2018 to $1,114k in 2019.

EEDO Response:

The increase in USoA account 5605 from 2018 to 2019 is primarily due to EEDO receiving a full year of shared service costs in 2019 versus only a part year in 2018, as EEDO was acquired by EPCOR in late 2018. All shared service costs charged from EPCOR affiliates to EEDO are included in USoA account 5605.

4-SEC-43
[Ex.4, 2-K] Please complete Appendix 2-K for all years back to EEDO's rebasing in 2013.

EEDO Response:

EEDO believes that this information was provided in the Appendix-2 that was submitted . Please reference the Appendix 2-K accompanying this submission.

https://www.rds.oeb.ca/CMWebDrawer/Record/750727/File/document

5-SEC-44
[Ex.5, pp. 8 &9] The table on page 8 shows that EEDO will have five affiliate Promissory Notes with EPCOR Utilities Inc. as follows:

Fixed Rate 3-Dec-18 30 $ 8,100,000 4.30%
Fixed Rate 1-Dec-20 30 $ 2,020,000 2.88%
Fixed Rate 15-Dec-21 30 $ 2,000,000 3.41%
Fixed Rate 31-Dec-22 30 $ 1,200,000 5.25%

Fixed Rate 31-Dec-23 30 $ 1,200,000 5.03%

On page 9 EEDO states 'For the 2022 Bridge Year and 2023 Test Year the OEB deemed long-term debt rate which were effective January 1, 2022 is not appropriate for the expected 2022 Bridge Year long-term debt issuance nor the expected 2023 long-term debt issuance. Debt markets have moved substantially since the 2022 OEB deemed long-term debt rates were established, using data from the fall of 2021.'

Please explain why EEDO feels that is unique and should not abide by the requirements as set out on page 53 of the 2009 Report of the Board on the Cost of Capital for Ontario's Utilities, which states that for affiliate fixed term debt the deemed long-term debt rate at the time of issuance will be used as a ceiling on the rate.

EEDO Response:

See response to 5-Staff-56 for the discussion on why EEDO believes its methodology for establishing long-term date rates results in a reasonable and valid market-based long-term date rate for the utility operations.

6-SEC-45

[Ex.6, p. 16, 2-H] EEDO has forecasted $715k in expenses for Municipal Services in 2023 and $600k in revenue:

a) Confirm that this expense and revenue is related to water & wastewater billing services on behalf of the Town of Collingwood.

EEDO Response: Confirmed

b) If not, what service(s) are included?

EEDO Response: N/A

a) Please explain why the revenue does not cover the expenses.

EEDO Response: The names of the two cells are inverted on the table. $715k is the projected revenue and $600k is the projected expense.

8-SEC-46

[Ex.8, pg. 17 and Table 8.10.1] EEDO's loss factor, based on a five-year average of actuals, has been reduced from 1.0710 to 1.0602 and EEDO states 'as this is a reduction, the Applicant is not proposing an action plan to reduce losses going forward'. Section 2.8.8 of the Filing Requirements states 'If the proposed distribution loss factor is greater than 5%, an explanation for the level of the loss factor, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward'. Please explain why EEDO has not proposed any actions with respect to its loss factor given that it is greater than 5% and that it has increased in 2020 and 2021 from 2019.

EEDO Response:

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

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

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

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

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

9-SEC-47

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

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

EEDO Response:

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

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

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

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

EEDO Response:

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

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

Refer to 9-Staff-87 for additional information.

9-SEC-48

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

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

EEDO Response:

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

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

EEDO Response:

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

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

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

EEDO Response:

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

- 2014 actual taxes paid - $165,187
- 2015 actual taxes paid – $178,697
- 2016 actual taxes paid - $146,927
- 2017 actual taxes paid - $138,233
- 2018 actual taxes paid - $264,453
- 2019 – 2021 actual taxes paid - $Nil

  Total 2013 to 2021- $1,010,437

d) If the amount paid in those years was less than that approved in 2013, did EEDO return the excess to customers?

EEDO Response:

Lower income taxes actually paid in 2019 to 2021 were not returned to customers and additional income taxes paid in 2013 to 2017 were not recovered from customers.

9-SEC-49

[Ex.9, DVA Continuity Schedule, OEB letter of July 25, 2019 Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance] EEDO has nothing recorded in Account 1592 – CCA Subaccount:

a) Did EEDO apply the accelerated CCA as referenced in the OEB's letter of July 25, 2019?

EEDO Response:

No.

b) If so, why is nothing recorded in this account?

EEDO Response:

See response to a) above.

c) If not, please explain why?

EEDO Response:

Accelerated CCA was not taken as EEDO was in a tax loss position for all years since 2019 and there would have been no benefit to EEDO or customers to take additional CCA claims in these years.

All of which is respectfully submitted.

EB-2022-0028

EPCOR Electricity Distribution Ontario Inc.

Responses to Vulnerable Electricity Consumers Coalition Interrogatories

August 25, 2022

EB-2022-0028

EEDO RESPONSE TO INTERROGATORIES

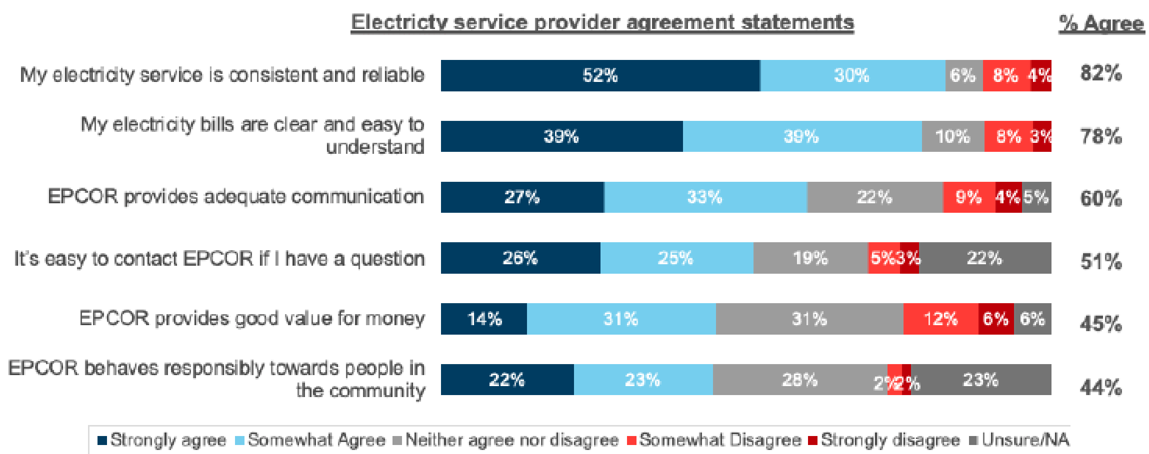
OF THE

Vulnerable Energy Consumers Coalition

1.0 ADMINISTRATION (EXHIBIT 1)

1.0-VECC-1

Reference: Exhibit 1, Tab 1, Schedule 1, page 40



a) The results of EEDO's customer engagement indicate that improvements in communication and customer contacts are warranted. Please explain what investments/changes are being introduced to improve performance in these areas.

EEDO Response:

EEDO plans to invest in the functionality to push SMS text based notifications to customers who sign up for this option. This permits EEDO to inform customers with planned and unplanned outage information without the customer having to go to our website for information. In addition, EEDO plans to continue to enhance its outage map should customers not want to receive texts from EPCOR, and want additional outage information.

EEDO is also planning an upgrade of our customer facing e-billing platform due to obsolesce of our existing model. This is being scoped along the Green Button implementation.

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**

Capital Contributions	(467)	(476)	(654)	(673)	(730)
Net Capital Expenditures	**3,299**	**3,700**	**3,391**	**3,585**	**3,905**
System O&M	2,645	2,711	2,856	2,848	2,905

d) Please explain what the "System OM&A" figures shown in Appendix 2-AB (of this proceeding) are representative of (e.g., showing the meaning of $-118,065 for 2021 etc.).

EEDO Response:

The System OM&A in Appendix 2-AB were corrected in "EEDO_2023 Chapter 2 Appendices_20220712" at the link below:

https://www.rds.oeb.ca/CMWebDrawer/Record/750727/File/document

and are representative of Operations and Maintenance OM&A costs as defined by Appendix 2-JA.

This also appears in the updated Chapter 2 Appendixes accompanying this submission.

e) Please confirm (or correct) that the "System OM&A" figures in Appendix 2-AB of the 2019 DSP represent the sub-total of only "Operations and Maintenance" OM&A costs (as defined by Appendix 2-JA)

EEDO Response:

EEDO confirms that the System OM&A figures in Appendix 2-AB of the 2019 DSP represent the sub-total of only "Operations and Maintenance" OM&A costs as defined by Appendix 2-JA.

2.0-VECC -3

Reference: Exhibit 2, Tab

a) What are the significant differences in either: (1) methodology or; (2) asset condition in the new DSP as compared to the DSP completed in the 2019?

EEDO Response:

The overall process of asset management has not changed significantly between the two DSP periods. What has changed is the quality of data coming from maintenance, inspection, GIS, and SCADA. This combined with an asset health index approach (Metsco appendix in the DSP), permits for a better condition assessment of critical assets like poles in order to optimally define and prioritize projects.

Improved maintenance procedures and assessments of our municipal substations have given EEDO better visibility into the conditions of our stations which aids in prioritizing investment in these assets.

2.0-VECC -4

Reference: Exhibit 2, Tab 1, Schedule 1, page 28

a) Please explain the nature of the 2019 SCADA investment of $305,635.

EEDO Response:

The Collingwood SCADA System was at end of life and obsolete. The previous assets were primarily provided by a vendor called C3-Ilex, who has since ceased operation and no longer supports the assets.

The primary goal of the project was to replace the obsolete assets with industry standard assets to ensure the ongoing operation of the Collingwood SCADA system. Project scope included:

- Procure new substation hardware, comms hardware, and SCADA head-end hardware
- Program substation equipment and head end equipment
- Contract with a local engineering firm to provide a drawing package for substation installations
- Contract with a local installer to install the hardware and commission
- Perform Network modifications as required to support the integration of the new assets into the SCADA system and separation from the existing business network.
- Cyber asset inventory and hardening of the new assets

b) Does EEDO have its own SCADA control room? If yes, when was this facility completed and at what cost.

EEDO Response:

EEDO has integrated its SCADA into the system control room in Edmonton whose role is to operate Edmonton's transmission and distribution network (EDTI). The integration into system control did not result in a capital cost. This has been done through an operational service level agreement where EEDO pays EPCOR Distribution & Transmission Inc. $25K/annually for operational supervision. EDTI control room operators are able to remote into EEDO's SCADA servers to gain visibility, and they are notified if there are SCADA alarms.

c) Does the SCADA operate on a 24/7 basis?

EEDO Response:

Yes

d) How many FTEs are dedicated to the SCADA control room operations (and allocated to EEDO)?

EEDO Response:

EEDO pays EDTI $25K/annually for SCADA supervision. EEDO is planning to increase that spend to $40K/annually in order to get additional support from system control in outage response. This scope would include system control operators working with EEDO's SmartMap tool which is our electrically connected real-time model of our system with SCADA and AMI data integrated. When there is an outage, system control room operators will be able to provide that first level of fault location by examining the SmartMap. With the addition of fault line indicators and remotely operable switches, system control will be able to fault locate, isolate and restore. If field support is required, system control will contact the on-call technician for support.

2.0-VECC -5

Reference: Exhibit 2, DSP, page 17 of 134

"*EEDO's target for this measure is that DSP actual spending to be within 10% of approved DSP capital budget. EEDO has not made a rate application since 2013 so comparison against approved budget is not relevant. Its annual capital budget is far above approved capital spend in 2013 largely due to load growth within the region and investments made into conditionally poor assets*."

a) Please clarify how the 10% variance metric is measure (i.e., gross or net capital and is it by spending category – "general plant".. etc.)

EEDO Response:

The variance will be measured on net capital basis. It is not measured by spending category, but rather as an annual budget.

b) EEDO did file a new DSP in 2019. Please provide the report for the 2019 through 2021 years on DSP metric performance and explain what performance bonuses were made with regard to that plan.

EEDO Response:

There were no performance bonuses made in relation to this metric. This metric was not measured in relation to the previous DSP. This is intended to be a performance measure going forward.

c) Please explain the consequences of not meeting the 10% metric.

EEDO Response:

The consequences of not meeting this plan is that it can create impacts to long term reliability and safety of the system because those projects either not completed or taking longer to complete than planned have been identified as being critical to those performance factors. EEDO has been making efforts to catch up on uncompleted or carryover capital leading into this coming DSP period.

2.0-VECC -6

Reference: Exhibit 2, Tab 2, Appendix A DSP, Section 5.2.3b

a) A significant portion of EEDO outages are due to loss of supply. Please elaborate on the most common reasons for supply loss and what efforts are being undertaken with Hydro One to reduce this cause of outages.

EEDO Response:

The primary reason for loss of supply is as a result of faulted feeders coming from Hydro One. The leading cause of faulted feeders is tree contact due to the distance of aerial lines and vegetation in our operating area. EEDO has plans to install fault line indicators in strategic areas on our grid that should provide visibility both down our feeders and up Hydro One feeders. This will reduce the time required to patrol the lines, often under tough night time conditions, to find the point of tree contact to clear a line before energizing. Both Hydro One and EEDO have plans to install remotely operated switches to be able to isolate faults, and reroute power to restore load.

2.0-VECC -7
Reference: Exhibit 2, Tab 2, Appendix A DSP, page 48 of 134

"*Mandatory asset replacements, due to near term significant safety or reliability issues are automatically included in the budget spend envelope. Non-Mandatory asset replacements are prioritized and scheduled. Non-Mandatory replacements provide a degree of planning flexibility to help keep annual capital expenditures stable*"

a) Please identify the mandatory projects for 2023 in Appendix 2-AA.

EEDO Response:

The miscellaneous pole replacement program and underground rebuild program are examples of mandatory projects because they involve a failed pole or faulted underground cable. Renewal is required in order to restore load. The relay replacement program is another example as EEDO is experiencing failed relays in its municipal stations.

2.0-VECC -8
Reference: Exhibit 2, Tab 2, Appendix 2AA DSP, pages 62-

FUNDING BY YEAR						
	2023	2024	2025	2026	2027	TOTAL
Capital Expenditure ($)	582,540	582,540	582,540	582,540	582,540	2,912,700
External Contribution ($)						
Net Capital Cost TOTAL	582,540	582,540	582,540	582,540	582,540	2,912,700
Capital Addition (%)	100%	100%	100%	100%	100%	100%
Operating Expenditure ($)	0	0	0	0	0	0

a) Please provide the number of poles replaced under the "Pole line replacement program" category (Appendix 2-AA) in each year 2013 through 2022 (forecast).

b) Please provide the number of poles forecast to be replaced under this program in each of the years 2023 – 2027.

EEDO Response:

a) Please refer to EEDO's response to 2-Staff-18 b)

b) This program budget is set at a forecast of replacing up to 40 poles a year.

2.0-VECC -9

Reference: Exhibit 2, Tab 2, Appendix A DSP, Section 5.4.2 Appendix 2-AB

a) Please clarify whether the capital contributions shown in Appendix 2-AB are related only to the category of "system access". If not please amend Appendix 2-AA to show capital contributions by category.

EEDO Response:

EEDO confirms that capital contributions are related solely to the System Access category.

b) Please explain how the capital contribution forecast of $730,672 was calculated for 2023.

EEDO Response:

This was calculated based on historical contributions made along with current actual projects planned in both customer contributed work and road relocations.

2.0-VECC -10

Reference: Exhibit 2, Tab 2, Appendix A DSP, Substation Upgrades

a) Why were there no investments made in substations (Appendix 2-AA Substation Upgrades) in any of the years 2013 through 2022?

EEDO Response:

From 2019 to 2022, EEDO has been investing in station SCADA and P&C (relay replacements). The relays have been replaced after failure, and EEDO has experienced an increase in relay failures of late necessitating a replacement program as planned within the 2023-2027 DSP. In addition, EEDO invested operational funds into substation grounding studies in between 2019 and 2022 and have been remedying any deficiencies found.

2.0-VECC -11

Reference: Exhibit 2, Tab 2, Appendix A DSP, Appendix 2-AA

a) What accounts for the large investment in underground rebuilds ($636,824) in 2021?

EEDO Response:

This investment relates to the rebuild of a section of underground line feeding the Collingwood marina and terminals. This involved extensive civil and restoration work. Reliable power to the Collingwood terminals is critical given the communications equipment deployed at the terminals is used for all emergency responders and utilities in the area.

This investment also relates to the Quebec Street underground installation for new residential development. As the planned development comprised of various individual developers and investors (instead of one developer), EPCOR financed this construction and customer are contributing as they connect based on a calculated economic evaluation to avoid an unnecessary burden on any one individual.

2.0-VECC -12

Reference: Exhibit 2, Tab 2, Appendix A DSP, Section 5.4.2

a) What is the estimated CCA (tax shield) in 2023 related ArcGIS Pro and Utility Network Migration capital program?

EEDO Response:

a) Based on the ArcGIS Pro and Utility Network Migration (proposed cost $508,602) being included as a Class 50 asset for tax purposes, the CCA would be approximately $140,000.

2.0-VECC -13

Reference: Exhibit 2, Tab 2, Appendix A DSP, Section 5.4.2

a) Why was their no investment in Vehicles/Fleet in 2021?

EEDO Response:

There was planned investment, but due to supply chain delays, the vehicles are not expected to be received until 2022.

b) Please list the vehicle orders made in 2020.

EEDO Response:

Tr 40-F550 4X4 Chassis with a 40' Altec boom for road load restriction season

2.0-VECC -14

Reference: Exhibit 2, Tab 2, Appendix A DSP, EB-2017-0373 page 31

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*

i. What explains the significant variation as between the capital forecast presented in EB-2017-0373 (late 2017 -2018) for the year 2019 ($3,256) and the actual spending in that year ($4,946 gross or $4,134 net)?

EEDO Response:

2019 ($4,134 vs $3,256) - Actual spending was higher relative to plan primarily due to spending on several system renewal capital projects carried forward from 2018 ($1,160k), a bucket truck that was planned to be purchased in 2018 ($334k), and higher spending on computer software/hardware as a result of integration ($204k). These increases were offset by a decrease in spending on planned system renewal projects from 2019 as a result of the spending on carried forward projects from 2018 (-$905k).

3.0 OPERATING REVENUE (EXHIBIT 3)

3.0-VECC -15

Reference: Exhibit 3, page 3

Preamble: The Application states:
"*The regression equations used to normalize and forecast EEDO's weather sensitive load use monthly weather variables: HDD and CDD as measured at Environment Canada's Collingwood Weather Station. This is the only weather station within EEDO's service territory. When temperatures were unavailable from the Colling Weather Station, temperatures from the Borden AWOS Weather Station were used*."

a) For how many months over historical period 2012-2021 were temperatures from the Borden AWOS Weather Station used?

b) Did EEDO/Elenchus undertake any analysis as to the comparability of temperature readings from the Collingwood Weather Station and the Borden AWOS Weather Station? If yes, what were the results?

EEDO Response:

a) Daily temperatures from the Borden AWOS were used on 49 of the 3,653 days from 2012 to 2021. The 49 days were spread across 35 months in the period.

b) Yes. As the number of days without data at the Collingwood Weather Station was relatively high, Elenchus calculated the typical difference between the Collingwood Weather Station and Borden AWOS. Daily average temperatures at the Borden AWOS were an average of 1.517°C colder than temperatures at the Collingwood Weather Station. To account for this typical variance, 1.517°C was added to the Borden AWOS temperatures when they were used in place of missing Collingwood Weather Station values.

3.0-VECC -16

Reference: Exhibit 3, pages 5 and 36 / Load Forecast Model, CDM Tab and CDM Adjustment Tab /EB-2021-0020, LRAMVA Workform

Preamble: The. Application states:
"*CDM data for each rate class that is used in the load forecast is from EEDO's last-approved LRAMVA workform (EB-2021-0020)*."

It is noted that the LRAMVA workform from EB-2021-0020 only includes CDM savings up to 2020 and the historical data used to estimate the Residential, GS<50 and GS>50 models does not include any adjustments to the 2021 data for the impact of CDM programs implemented in 2021.

It is noted that at page 36 the Application includes estimates as to the impact in 2021 of CDM programs implemented in 2021.

a) Please re-do the regression models for the Residential, GS<50 and GS>50 classes using 2021 monthly consumption values adjusted for the 2021 CDM program savings set out on page 36. For each of the three classes please provide: i) the resulting models and their related statistics, ii) the forecast consumption for 2022 and 2023 (assuming no CDM) and iii) the forecast consumption for 2022 and 2023 (after removing persisting CDM). Note: The Load Forecast Model will need to be revised so as to include 2021 program savings in the CDM Tab and exclude them from the CDM Adjustment Tab.

EEDO Response:

Please see 3-Staff-41 Attachment 1.

The results of this scenario are provided below.

kWh	2022 Weather Normal Forecast	CDM Adjustment	2022 CDM Adjusted Forecast
Residential	137,535,826	68,670	137,467,156
GS < 50	44,618,238	270,812	44,347,426
GS > 50	130,186,412	725,008	129,461,404
Street Light	1,232,119		1,232,119
USL	396,233		396,233
Total	313,968,828	1,064,491	312,904,338

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

3.0-VECC -17

Reference: Exhibit 3, page 7

Preamble: The Application states:
"*The extent to which to Residential consumption was higher than typical consumption was found to be related to the weather variables in those months. A set of COVID/weather interaction variables were considered to capture the incremental consumption caused by people working from home and more generally 6 staying at home due to lockdowns.*
These variables, "COVID HDD" and "COVID CDD" are equal to the relevant HDD and CDD variables from March 2020 to December 2021 and equal to 0 in all other months. The coefficients reflect incremental heating and cooling load from people working from home, public health lockdowns, and people generally staying at home."

a) Did EEDO/Elenchus test alternative COVID flag variables for the Residential class? If yes, what variables were tested and did the results using the "COVID HDD" and "COVID CDD" variables provide the best statistical results?

EEDO Response:

Yes, Elenchus tested alternative COVID flag variables for the Residential class. The COVID HDD and COVID HDD variables provided the lowest mean absolute percentage error (MAPE) and highest R-squared than other COVID variables. Additionally, the t-statistics of the other variables (HDD16, CDD16, Residential Customer Count, etc) were higher when the COVID HDD and COVID CDD variables were used.

3.0-VECC -18

Reference: Exhibit 3, page 13

Preamble: The Application states:
"COVID flag variables were tested and found to be statistically significant for the General Service< 50 kW and General Service > 50 kW classes. A "COVID" variable equal to 0 in all months prior to March 2020 and 1 in all months since March 2020; a "COVID_AM" variable equal to 0 in all months prior to March 2020, equal to 1 in April and May 2020, and 0.5 in each month from June 15 2020 to December 2021; and a "COVID2020" variable equal to 0.5 in March 2020, 1 in April and May 2020, 0.5

in June 2020, and 0 each month thereafter, were tested. The "COVID_AM" variable considers the incremental impact in the first few months of the pandemic, with lower impacts after May 2020. The "COVID2020" variable also considers the larger impact in the first few months of the pandemic but the impact ceasing by Summer 2020. The "COVID_AM" variable is used for the General Service < 50 kW class and "COVID2020" is used for the General Service > 50 kW rate class."

a) Were all three COVID flag variables tested for the GS<50 class? If not, why not?
b) Of the three COVID flag variables did the "COVID_AM" variable yield the best statistical results for the GS<50 class?
c) Were all three COVID flag variables tested for the GS>50 class? If not, why not?
d) Of the three COVID flag variables did the "COVID2020" variable yield the best statistical results for the GS>50 class?

EEDO Response:

a) Yes, all three COVID flag variables were tested for the GS<50 kW class.
b) Yes, the COVID_AM variable yielded the best statistical results.
c) Yes, all three COVID flag variables were tested for the GS>50 kW class.
d) Yes, the COVID_2020 variable yielded the best statistical results.

3.0-VECC -19

Reference: Exhibit 3, pages 11-12

Preamble: The Application states:
"*Weather-normalized consumption and forecast values are calculated for the Residential class in Table 3.1-6 below, which incorporates the 10-year weather normal HDD and CDD, month days, customer count, binary shoulder variable, and COVID degree day variables. Forecast COVID-related values are adjusted downward by 50% in 2022 and 75% in 2023 to reflect the gradual declining impacts of COVID*."

a) Please provide a revised version of Table 3.1-6 where the COVID-related values are adjusted downward by 50% in 2023.

EEDO Response:

A revised Table 3.1-6 with COVID-related values adjusted downward by 50% is provided below.

Residential kWh						
Year	Actual	Cumulative Persisting CDM	Actual No CDM	Normal Predicted No CDM	Cumulative Persisting CDM	Normalized
	A	B	C = A + B	D	E = B	F = D - E
2012	116,167,787	91,399	116,259,186	117,736,700	91,399	117,645,301
2013	121,392,228	275,682	121,667,910	119,675,281	275,682	119,399,599
2014	122,734,566	684,035	123,418,602	120,840,873	684,035	120,156,837
2015	120,270,467	1,232,499	121,502,966	122,067,600	1,232,499	120,835,101
2016	119,372,519	2,380,443	121,752,963	124,063,098	2,380,443	121,682,654
2017	116,589,912	5,089,988	121,679,900	126,135,978	5,089,988	121,045,990
2018	127,042,389	6,903,258	133,945,647	128,491,882	6,903,258	121,588,623
2019	125,937,194	7,269,766	133,206,960	131,176,517	7,269,766	123,906,751
2020	134,775,706	7,258,555	142,034,261	142,562,722	7,258,555	135,304,166
2021	136,991,339	6,090,798	143,082,138	145,956,572	6,090,798	139,865,774
2022				143,635,795	6,066,581	137,569,214
2023				146,022,701	5,984,798	140,037,903

3.0-VECC -20

Reference: Exhibit 3, pages 13, 19, 26, 30 and 34

a) Please provide the actual customer/connection counts for each customer class for the most recent month available.

EEDO Response:

As of July 2022:

- Residential: 16,647 customers
- GS<50kW: 1,821 customers
- GS>50kW: 125 customers
- Streetlight: 3 customers, 3,261 connections
- Unmetered Scattered Load: 30 customers

3.0-VECC -21

Reference: Exhibit 3, pages 4-5
Load Forecast Model, Economic Tab

a) The GDP forecast used in the Application is the average of the public forecasts from four major banks (BMO, TD, Scotiabank, and RBC, as of March 31, 2022). However, the Economic Tab in the Load Forecast model also includes a GDP forecast from CIBC. Why was CIBC excluded for purposes of the Application?

EEDO Response:

Unlike the four major banks included in the economic forecasts, CIBC does not regularly publish provincial forecast data. Each bank, except CIBC, had published a new forecast in the month of March 2022 so CIBC data was excluded because it was out of date. Elenchus does not necessarily consider economic forecasts that are 2.5 months old to be out of date, however, economic conditions were changing at a faster pace in this period due to the reduced impact of the Omicron variant (compared to mid-January) and increased inflation expectations.

3.0-VECC -22

Reference: Exhibit 3, pages 31

a) Please confirm that Table 3.1-19 relates to the Street Light class and not the GS>50 class.

EEDO Response: Confirmed

3.0-VECC -23

Reference: Exhibit 3, pages 34-35

a) Please provide versions Table 3.1-23 that show: i) EEDO's Residential kWh usage as a percentage of the total Provincial Residential kWh usage, ii) EEDO's GS<50 kWh usage as a percentage of the total Provincial GS<50 kWh usage and iii) EEDO's GS<50 kWh usage as a percentage of the total Provincial GS>50 kWh usage.

b) Are the 2021-2024 CDM Framework programs that target Commercial and Industrial Users just meant to apply to customers of LDCs or also to transmission-connected commercial and industrial customers that are not served by an LDC?

c) Is the EEDO's Energy Affordability Program allocation based on the number of households in Collingwood within the Low-Income Measure (after tax) as a share of: i) all Ontario households or ii) all Ontario households meeting the Low-Income Measure criteria?

d) Is Statistics Canada the source of the data for the number of households in Collingwood within the Low-Income Measure (after tax)? If not, what is the source?

EEDO Response:

a) Versions of Table 3.1-23 for the Residential, GS<50 kW, and GS>50 kW classes are provided below.

i. Residential			
Year	Provincial kWh	EEDO kWh	EEDO % Share
2016	39,196,063,132	117,557,987	0.30%
2017	38,088,034,111	116,631,538	0.31%
2018	41,318,383,306	126,982,163	0.31%
2019	40,381,980,426	125,942,764	0.31%
2020	43,244,522,381	134,777,552	0.31%
5-Year Avg.	**40,445,796,671**	**124,378,401**	**0.31%**

ii. GS < 50 kW			
Year	Provincial kWh	EEDO kWh	EEDO % Share
2016	13,194,493,806	45,960,686	0.35%
2017	13,005,545,376	45,205,488	0.35%
2018	13,542,967,467	47,152,725	0.35%
2019	13,351,192,367	46,523,087	0.35%
2020	12,532,160,615	42,533,574	0.34%
5-Year Avg.	**13,125,271,926**	**45,475,112**	**0.35%**

iii. GS > 50 kW			
Year	**Provincial kWh**	**EEDO kWh**	**EEDO % Share**
2016	63,716,850,210	132,829,263	0.21%
2017	63,722,025,934	127,833,335	0.20%
2018	65,275,749,273	133,500,883	0.20%
2019	64,284,293,740	129,239,782	0.20%
2020	60,782,716,311	118,373,282	0.19%
5-Year Avg.	**63,556,327,094**	**128,355,309**	**0.20%**

b) Elenchus's understanding is that the 2021-2024 CDM Framework programs apply to all commercial and industrial customers.

c) The Energy Affordability Program allocation is based on the number of Collingwood households as a share of (ii) all Ontario households meeting the Low-Income Measure criteria.

d) Statistics Canada is the source of the LIM data.

4.0 OPERATING COSTS (EXHIBIT 4)

4.0 -VECC -24

Reference: Exhibit 4

a) What are the incremental operating costs associated with the ArcGIS Pro and Utility Network Migration project?

EEDO Response:

EEDO does not anticipate there to be incremental operating costs with respect to the ArcGIS Pro and Utility Network Migration project. There will be software license fees but they are expected to replace current license fees.

4.0 -VECC -25

Reference: Exhibit 4, pages EB-2017-0373 , page 31

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*

a) What accounts for the significant difference between what EPCOR presented as its estimates for OM&A in EB-2017 – 0373 and the actuals spending in years 2019 through 2021 and the estimates for 2022 and 2023?

b) What was the date of the final submission of EPCOR in EB-2017-0373?

EEDO Response:

a) Please see EEDO's response to 4-SEC-32

b) The date of final submission of EPCOR in EB-2017-0373 was June 29, 2018: EPCOR_ReplySUB_MAADs_20190629

https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber%3DEB-2017-0373&sortBy=recRegisteredOn-&pageSize=400

4.0 -VECC -26
Reference: Exhibit 4,

a) Please provide the incremental COVID OM&A costs for each year 2020 and 2021.

b) Are the costs provided in response to a) included in Appendices 2-JA or 2-JD?

c) Are any of the regulatory costs associated with this application included in the years 2020 or 2021 in Appendix 2-JA?

EEDO Response:

a)

COVID Categories	2020	2021
Other Costs	19,827	9,394
Bad Debt	20,712	(20,712)

b) The incremental COVID OM&A costs have been excluded from the OM&A costs in Appendix 2-JA/2-JD

c) The costs associated with this application have been excluded from Appendix 2-JA.

4.0 -VECC -27
Reference: Exhibit 4, Tab 1, Schedule 1, page 9

Table 4.1.2-1

Judicial Inquiry Costs by year

		A	B	C	D	E
	Expense	**2018**	**2019**	**2020**	**2021**	**Total**

1	Judicial Inquiry costs	59,748	962,287	61,268	182,866	1,266,169

"*All costs associated with the judicial inquiry have been excluded in this Exhibit and the Cost 14 of Service Application*."

a) Do any of the costs shown in Table 4.1.2-1 appear in either Appendices 2-JA or 2-JD?

EEDO Response:

The judicial inquiry costs have been excluded from Appendix 2-JA and 2-JD.

4.0 -VECC -28
Reference: Exhibit 4, Tab 1, Schedule 1 page 29

"*These decreases were partially offset by higher incentive pay of $68,000 as a result of above Target performance of the short-term incentive plan in 2021*."

a) Please explain what is "Target performance" – and explain what results in 2021 resulted in the increase performance payout in 2021.

EEDO Response:

Please see 4-Staff-46 e) for an explanation of Target performance.

Part of EPCOR's Short Term Incentive plan relates to EUI net income performance (referred to as Pool B Short Term Incentive). If EUI net income is above set targets, overall Short Term Incentive can be increased above Target in a year.

EEDO has not applied to recover any Pool B Short Term Incentive costs for EEDO employees in its 2023 Test Year costs.

4.0 -VECC -29
Reference: Exhibit 4, Tab 1, Schedule 1 page 37

a) If EEDO is a member of the EDA please provide the annual membership dues for each year since 2013 and including 2023 (forecast).

EEDO Response:

Year	Amount ($)
2013	29,000
2014	31,100
2015	32,200

2016	32,500
2017	32,800
2018	33,500
2019	34,200
2020	34,900
2021	35,200
2022	35,200
2023	35,500

4.0 -VECC -30
Reference: Exhibit 4, Tab 1, Schedule 1 page 40 Appendix 2-k

a) Please amend Table 4.4.1-1 (Appendix 2-K) to show the total compensation capitalized and expensed in the years 2013 – 2023.

EEDO Response:

EEDO believes it has provided the total compensation capitalized and expensed in the years 2013- 2023 in the bottom section of the Table 4.4.1-1.

EEDO has provided the aggregate total compensation capitalized and expensed for the 2013 – 2023 years in the table below.

Compensation Breakdown	**2013-2023**
OM&A	26,940,535
Capital	10,904,834
Total	37,845,369

4.0 -VECC -31
Reference: Exhibit 4, Tab 1, Schedule 1 page 45

"*The CEO position went vacant in 2015 and was not replaced. Executive oversight is now provided from EOOMI with approximately 35% of two positions allocated to EEDO for the 2023 Test Year. The HR Manager position was replaced by a HR Consultant position with approximately 35% of the position allocated to EEDO for the 2023 Test Year*"

a) What portion of Account 5605 – Executive Salaries and Expenses – amount of $1,665,154 in 2023 is related to the two positions allocated to EEDO?

EEDO Response:

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.

c) Please provide all the affiliate billings/invoice for services for each year 2019 through 2022 (to-date).

EEDO Response:

Invoices for EOOMI, EOUI EDTI and EWSI are attached as an appendix.

EUI costs are passed through to EEDO via journal entry and trued up to actual costs at the end of each year. For 2019, EOUI costs were passed through to EEDO via journal entry and trued up to actual costs at the end of the year.

d) Please explain what "Public and Government Affairs (P&GA)" services were provided in each year 2019, 2021 and 2022.

EEDO Response:

P&GA services provided by EWSI primarily related to assistance with internal and external communications and stakeholder/public consultation.

4.0 -VECC -34

Reference: Exhibit 4, Tab 1, Schedule 1 page 66, 72-73

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

a) How many regulatory analysts does EOOMI/EOUI employ who perform work for Ontario Utilities?

EEDO Response:

As noted in b. on page 68 of Exhibit 4, EOOMI has 1 Analyst, Regulatory that performs work for Ontario Utilities.

b) How many regulatory analyst FTEs has EOOMI/EOUI allocated to: (1)EPCOR Electricity Distribution Ontario; (2) EPCOR Natural Gas Limited Partnership – Aylmer; (3) EPCOR Natural Gas Limited Partnership – South Bruce?

EEDO Response:

EOOMI expects to allocate approximately 0.33 Regulatory, Analyst FTEs to each of EEDO, EPCOR Natural Gas Limited Partnership – Aylmer and EPCOR Natural Gas Limited Partnership – South Bruce for the 2023 Test Year.

4.0 -VECC -35

Reference: Exhibit 4, Tab 1, Schedule 1 ; Tables 4.4.2-1 and 4.4.4-7

a) Please explain the difference between Table 4.4.2-1 which shows for 2023 $790,070 in Affiliated Shared Service costs and Table 4.4.2-7 which shows $733,970 in costs.

EEDO Response:

Table 4.4.2-1 shows the total of all Affiliate Shared Services of $790,070 for the 2023 Test Year. This includes the 2023 Test Year amount shown for Table 4.4.2-7 as well as for Tables 4.4.2-3 and 4.4.2-4. The summarization of all Affiliate Shared Services is shown in Table 4.4.2-2.

4.0 -VECC -36

Reference: Exhibit 4, Tab 1, Schedule 1 Tables 4.4.2-7/-13

a) Please explain the difference between the HR services provided by EOOMI/EOUI and those provided by EUI.

EEDO Response:

HR services provided by EOOMI are discussed in c. on page 66 of Exhibit 4 and these include on-the-ground HR support provided directly to EEDO.

HR Services provided by EUI are described in b. on page 82 of Exhibit 4. These services include supporting the work performed by EOOMI, as well as providing overall governance and oversight of the HR function across all of EPCOR's operations, setting HR policies, administration and management of the shared Human Resources and Information System and providing payroll functions to all EPCOR's Canadian operations.

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.

c) The pole attachment charge used was $34.76 per the Wireline Pole Attachment Charge decision (EB-2021-0302 December 16, 2021) for the 2022 year.

7.0 COST ALLOCATION (EXHIBIT 7)

7.0-VECC-39

Reference: Exhibit 7, page 2

a) Please provide a copy of the analysis performed to develop the weighting factors for Billing and Collecting.

EEDO Response:

The analysis is provided as 7-VECC-39 Attachment 1.

7.0-VECC-40

Reference: Exhibit 7, page 3 / Cost Allocation Model, Tab I7.2
Exhibit 3, page 19

Preamble: The Application states: "*EEDO completed an analysis of the costs included in meter reading and assigned the costs to the appropriate type of meter based on the nature of the cost. Based on this activity analysis, EEDO 11 calculated the overall cost per meter and assigned a weighting of 1 for the meter reading costs 12 related to smart AMI meters.*"

a) Please provide a copy of the analysis performed to develop the Meter Reading weighting factors.

b) In Exhibit 3 the 2023 forecast customer count for the GS<50 class is 1,832.7. However, in the Meter Reading Tab of the Cost Allocation Model the number of GS<50 meters is 1,733. Please reconcile.

EEDO Response:

a) Please see 7-Staff-62.

b) Please see 7-Staff-63.

7.0-VECC-41

Reference: Exhibit 7, Cost Allocation Model, Tab I4 (BO Assets)

a) Please provide a schedule that compares the primary/secondary asset breakout in the current Application with that used in the utility's last COS Application for the following accounts: i) #1830, ii) #1835, iii) #1840 and iv)

#1845. Please explain any material changes (i.e., greater than five percentage points).

EEDO Response:

USoA	Account Name	2013 Splits	2023 Splits
1830-4	Poles, Towers and Fixtures - Primary	85.00%	85.00%
1830-5	Poles, Towers and Fixtures - Secondary	15.00%	15.00%
1835-4	Overhead Conductors and Devices - Primary	85.00%	85.00%
1835-5	Overhead Conductors and Devices - Secondary	15.00%	15.00%
1840-4	Underground Conduit - Primary	50.00%	40.00%
1840-5	Underground Conduit - Secondary	50.00%	60.00%
1845-4	Underground Conductors and Devices - Primary	69.00%	50.00%
1845-5	Underground Conductors and Devices - Secondary	31.00%	50.00%

Regarding changes to the underground assumptions (1840), based on discussions with the operations team, there is a higher allocation of primary than secondary as the same type of conduit is used for both services. Primary conductor is more expensive than secondary which offset the ratio used for conduit.

7.0-VECC-42

Reference: Exhibit 7, page 11

Preamble: The Application states:"*To maintain revenue neutrality, EEDO proposes to increase revenues from USL and General Service > 50 kW, the two classes with the lowest Revenue to Cost Ratios. The revenue to cost ratios of the General Service > 50 kW and USL classes are within the target range and remain the lowest revenue to cost ratios after the revenue reallocation from Street Light.*"

a) In Table 7.3-1 the Residential class' Revenue to Cost Ratio increases from 98.67% to 99.22%. Is part or all of this increase also due to explicitly increasing ratio so as to maintain revenue neutrality?

EEDO Response:

Yes, the full increase from 98.67% to 99.22% is to maintain revenue neutrality.

7.0-VECC-43

Reference: Exhibit 7, page 5

Preamble: The Application states: "In its last Cost of Service application (EB-2012-0116), EEDO used the load profiles provided by Hydro One in its cost allocation model."

a) Please provide a version of the 2023 Cost Allocation Model where the load profiles are based those provided by Hydro One.

EEDO Response:

A version of the 2032 Cost Allocation Model based on the same load profiles used in EB-2012-0116 is provided as 7-VECC-43 Attachment 1.

7.0-VECC-44

Reference: Exhibit 7, pages 5-10

Preamble: The Application states (page 5):
"*EEDO has updated the load profiles for all rate classes.*"

a) The Application describes the methodology used to update the load profiles for the Residential, GS<50 and GS>50 classes. How were the load profiles for the Street Light and USL classes updated?

EEDO Response:

Please see 7-Staff-64, part c).

7.0-VECC-45

Reference: Exhibit 7, pages 5-10

Preamble: The Application states (page 8):
"*Actual 2019 hourly load is adjusted by calculating the difference between actual daily temperatures and the corresponding ranked typical daily temperature (as identified in Figure 2) and applying the regression coefficient to the difference. The year 2019 was selected as the base year to scale to avoid irregular consumption patterns in 2020 and 2021 caused by the COVID-19 pandemic that are expected to diminish by the 2023 Test Year.*"

The Application states (page 7):
"*The impact of HDDs and CDDs on hourly load is calculated with a regression of three years of actual hourly loads (2019 to 2021) on daily HDDs and CDDs. The regression results provide*

the estimated impact of a change in degree days on load."

a) Why is it appropriate use 2020 and 2021 data to determine the impact of HDDs and CDDs on hourly load but not use 2020 or 2021 for purposes of calculating the load profiles for each class, particularly when the regression model used to determine the impact of HDD and CDD on load includes variables to account for the impact of COVID (per page 8, lines 3-4)?

b) Please provide the results (i.e., the 2023 CP and NCP values) for each customer class based on: i) adjusted 2020 data and ii) adjusted 2021 data.

EEDO Response:

a) The 2020 and 2021 data is used only for the purposes of deriving HDD and CDD coefficients used for weather-normalizing 2019 hourly demands. Despite the influence of COVID on demands, which are somewhat mitigated by the COVID HDD and COVID CDD variables, including 2020 and 2021 data provides a more timely and robust 3-year dataset to derive the weather normalization factors. Using 2020 or 2021 data hourly loads, with weather normalizing adjustments, as the basis for deriving CP and NCP figures would inappropriately include the impacts of lockdowns and COVID waves at different times of the year that should not be reflected in forecast data.

b) The results are provided in 7-VECC-45 Attachment 1.

7.0-VECC-46

Reference: Exhibit 7, pages 5-10

Preamble: The Application states (page 8, footnote 2):
"There are a total of 77 independent variables, however, the set of 72 for hourly HDD, hourly CDD and binary Hour variables have only three non-zero values in each observation. The values are 0 in each hour other than the HDD, CDD, and binary hour variables that correspond to the hour of the observation. This regression is similar to 24 regressions, one for each hour of the day."

a) Would the results be "exactly" the same if 24 separate regressions had been done – one for each hour of the day?

EEDO Response:

The results would be almost the exact same if 24 separate regressions were run. If the trend, weekend, holiday, COVIDHDD and COVIDCDD variables were excluded, then the results would be exactly the same if 24 separate regressions were run.

7.0-VECC-47

Reference: Exhibit 7, pages 5-10

Preamble: The Application states ():
"*There are 24 variables for each of HDD and CDD, equal to the actual degree days in the corresponding hour, and 0 in all other hours. A set of 24 binary variables, equal to 1 in the corresponding hour and 0 in all other hours; COVIDHDD and COVIDCDD variables equal to 0 in all days until March 16, 2020 and equal to the relevant HDD or CDD in each hour thereafter; a trend variable; a Weekend binary variable; and a Holiday binary variable are also included. The resulting coefficients reflect the impact of one HDD or CDD that considers different impacts depending on the hour of the day*."

a) Please confirm that by using binary variables to account for the impact of weekends and holidays as opposed to weekdays on load the model implicitly assumes that the impact of a change in HDD or CDD value is the same on weekends and holidays as it is on weekdays. If confirmed, please explain why this "assumption" is reasonable? If not confirmed, please explain why not.

EEDO Response:

Confirmed. This is a simplifying assumption to maintain a reasonable number of variables used in the regression. Separate HDD and CDD variables by weekday, weekend, and holiday would require 144 variables, plus the remaining 27 variables used for a total of 171 variables.

8.0 RATE DESIGN (EXHIBIT 8)

8.0-VECC-48

Reference: Exhibit 8, page 4
2023 Cost Allocation Model, Tab O2

a) The Minimum System with PLCC Adjustment (Ceiling) values in Table 8.1-3 do not match those in Tab O2 of the cost allocation model. Please reconcile and comment on whether the proposed 2023 monthly service charges for each customer class are appropriate.

EEDO Response:

Table 8.1-3 is out of date and reflects an earlier run of the cost allocation model. An updated Table 8.1-3 is provided below. EEDO's rate design, however, is based on the final cost allocation model and not this earlier version. Aside from the Residential rate, the only fixed charge that exceeds the Minimum System with PLCC Adjustment is the GS>50 kW class, which has been maintained at $110.21. The proposed 2023 monthly service charges for each class are appropriate, however, please note the rates have been updated as part of responses to interrogatories.

Rate Class	2022 Current Monthly Service Charge	2023 Proposed Monthly Service Charge	Customer Unit Cost per Month – Avoided Cost (Floor)	Minimum System with PLCC Adjustment (Ceiling)
Residential	$27.24	$31.43	$5.94	$22.77
GS <50	$23.07	$26.46	$8.74	$28.90
GS >50	$110.21	$110.21	$22.28	$57.23
Street Light	$4.03	$1.94	$0.00	$1.94
USL	$0.56	$0.78	$2.41	$11.85

8.0-VECC-49

Reference: Exhibit 8, pages 5-6
2023 Cost Allocation Model, Tab I6.1

a) Please explain how the 185,000 kW forecast of GS>50 billing demand eligible for the transformer ownership discount was established.

EEDO Response:

The 185,000kW is the historical five year average used for billing purposes from 2017-2021.

8.0-VECC-50

Reference: Exhibit 8, pages 8
RTSR Workform

a) Please confirm that the customer class billing kWh and kW in Tab 3 of the RTSR Workform are based on the 2023 load forecast.

EEDO Response: Confirmed

b) What year's data is used for the Network, Line Connection and Transformation Connection billing units used in Tabs 5, 6 and 7 of the RTSR Workform.

EEDO Response: 2021 actuals were used.

c) Please provide a revised version of the RTSR Workform where the customer class billing units used in Tab 3 are based on the same year as the billing unit data used in Tabs 5-7.

EEDO Response: An updated RTSR workform has been completed as per 1-Staff-1, which includes 2021 RRR data.

8.0-VECC-51

Reference: Exhibit 8, page 18
Appendix 2-R

a) How much embedded generation did EEDO purchase in each of the years 2017-2021?

EEDO Response:

Year	Embedded Generation (kWh)
2017	2,016,229
2018	1,954,753
2019	1,866,884
2020	1,891,300
2021	1,891,037
Total	**9,620,203**

b) Please confirm that, per the notes in Appendix 2-R, the values in line A(1) do not include embedded generation purchases but the values in line A(2) do.

EEDO Response:

The original submission did not. This has been adjusted in the revised App.2-R_Loss Factors accompanying this submission.

DEFERRAL AND VARIANCE ACCOUNTS (EXHIBIT 9)

9.0 –VECC -52

Reference: Exhibit 9, Tab 1, Schedule 1, page 9 /Table 9.1-5

a) A number of Group 2 deferral accounts have balances below the Utility's material threshold amount of 10k. What is the rationale for disposition of these accounts?

EEDO Response:

These amounts have been removed from the DVA table and are no longer being requested for disposition

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* *after 2016, EEDO has included $216,722 in the Group 2 DVA balance as part of this application*."

a) The above statement is made with respect to Account 1508 Deferred IFRS Transition Costs, which seeks to recover from ratepayers of an amount of $216,722. Please explain how it is that EEDO rather than the prior owners "*completed the transition to IFRS in 2016*".

b) The IFRS transition was completed in 2016. EEDO sought deferment of rate rebasing (and deferral of account disposition). Why it is reasonable for ratepayers to be ordered to now pay this amount. Specifically address why any carrying charges should be at the expense of ratepayers rather than the shareholder who choose to defer recovery of this sub-account.

c) Please amend Table 9.1-5 to add a column with the actual balances on December 31, 2018.

EEDO Response:

a) For clarity, Collus PowerStream completed the transition to IFRS in 2016 and was subsequently acquired in 2018 and became EEDO.

b) As part of the OEB's August 30th, 2018 decision and order for EB-2017-0373 and EB-2017-0374, EEDO was approved to continue to track costs in the deferral and variance accounts that were currently approved and to seek disposition of their balances at a future date.

With respect to the carrying charges, rate payers have been receiving the benefit of not having to re-pay the IFRS transition costs as a result of the deferral of disposition. The carrying charges associated with the deferral account reflect the cost that the utility has been incurring as a result of financing these costs on behalf of the ratepayer.

c)

	A	B	C	D	D	E	F	C
	Account	**Name**	**Dec 31, 2022 Balance**	**Carrying Charges**	**Dispoition Proposal**	**Year of Previous Disposition**	**Continuance**	**Dec 31, 2018 Balance**
1	1508	Deferred IFRS Transition Costs	$189,206	$27,516	$216,722	N/A	No	$189,206
2	1508	Pole Attachment Revenue Variance	($492,217)	($10,122)	($502,339)	N/A	No	($11,657)
3	1508	Retail Service Charge Incremental Revenue	($29,083)	($470)	($29,554)	N/A	No	$0
4	1508	Customer Choice Initiative Costs	$8,500	$134	$8,634	N/A	Yes	$0
5	1508	Other Regulatory Assets - Icon F&G Meter Disposal	$512,493	$56,910	$569,403	N/A	No	$512,493
6	1508	Other Regulatory Assets - OEB Cost Assessment Variance	$235,952	$10,168	$246,120	N/A	No	$100,469
7	1508	Other Regulatory Assets - Energy East Consultation Costs	$2,275	$226	$2,501	N/A	No	$2,275
8	1508	Other Regulatory Assets - LPP Variance	($2,217)	$0	($2,217)	N/A	No	($2,217)
9	1509	COVID-19 Deferral Account	$40,600	$1,138	$41,738	N/A	No	$0
10	1525	Misc. Deferred Debits	$8,105	$0	$0	N/A	Yes	$40,745
11	1592	PILs and Tax Variance for 2006 and Subsequent Years	$35,000	$3,427	$38,427	N/A	Yes	$35,000
13	1531	REG Capital Deferral Account	$1,269	$217	$1,486	2013	No	$1,269
14	1532	REG Capital OM&A Account	$43,444	$1,787	$45,230	2013	No	$16,523

15	1534	Smart Grid Capital Deferral Account	$4,500	$578	$5,078	2013	No	$4,500
16	1555	Smart Grid Capital Deferral - Stranded Meters	$3,650	$6,527	$10,177	N/A	No	$3,650
17	1557	Meter Cost Deferral Account (MIST Meters)	$250,901	$14,423	$265,324	N/A	No	$210,744
18		**Total**	**812,377**	**112,460**	**916,731**			**1,102,999**

9.0 –VECC -55

Reference: Exhibit 9, Tab 1, Schedule 1, page 16

a) In 2013 the amounts built into rates for Collection (account 5320) and Bad Debt expense (account 5335) were $119,586 and 60k respectively. In 2020 the actual costs incurred were $92,750 and (again) 60k. In 2021 the incurred costs were $133,038 and 4k (Appendix 2-JD). Please how the figure of lost revenues of $43,464 and bad debt of $20,712 was derived.

b) Please explain the rationale for the continuance of the COVID account in 2023 and beyond.

EEDO Response:

a) The lost revenues of $43,464 is based on what interest charges were foregone and was determined based on waived charges from EEDO's billing system.

   COVID bad debt of $20,712 was derived based on the excess of the bad debt expense relative to the 2013 approved bad debt expense. Note that the 2020 bad debt expense was $60k as the excess was deferred into the COVID deferral account. EEDO notes that the $20,712 was reversed in 2021 as bad debt experience decreased relative to 2020; EEDO is not requesting deferral account disposal relating to COVID bad debt.

b) The account was requested to remain open as the COVID-19 pandemic was a going concern there remained uncertainly regarding additional pandemic waves and impacts on operations. Based on more current information and provincial mandates, EEDO withdraws the request to keep the account open.

All of which is respectfully submitted.

EPCOR

EB-2022-0028

EPCOR Electricity Distribution Ontario Inc.

Responses to Environmental Defence Interrogatories

August 25, 2022

EB-2022-0028

EEDO RESPONSE TO INTERROGATORIES

of

Environmental Defence

1. Reference: Exhibit 1, Tab 1, Schedule 1, Page 20

Preamble:

The planning assumptions and approaches used to develop both the strategic direction of EEDO and its DSP are the following:

a) EEDO's load service requirement will continue to grow at approximately 2% per annum.

[…]

c) Before EEDO builds new capacity, it will consider the impact of DER penetration as well as non-wires alternatives that are expected to be more available over the next 5 years.

d) EEDO's customers will continue to adopt DER technology including electric vehicles which will require a modernized and updated grid management system.

Questions:

(a) Please confirm whether the assumed 2% per annum anticipated growth of load service includes anticipated load growth due to increased electrification of transportation (i.e., electric vehicles) and space heating (i.e., high efficiency cold climate heat pumps) related to ongoing decarbonization efforts. If so, please provide any studies or reports that EEDO relied on to reach this assumption.

EEDO Response:

The 2% per annum assumption does not include any material impact from EV or heat pump penetration. EEDO does not have sufficient data to justify the adjustment of planning assumptions based on these forecasts, but continues to monitor the environment and the experiences of other utilities in Ontario and elsewhere.

(b) Please explain how EEDO considers the impact of DER penetration and non-wires alternatives over the next 5-years in planning for new capacity building. Please file any guidelines, standards or processes that EEDO uses when considering the impact of DERs and NWAs for planning purposes.

EEDO Response:

EEDO's capacity driven projects within this DSP period relate to the upgrade of the Stayner MS transformers from 5MVA to 7.5MVA. During the preparation of this plan, EEDO was not made aware of any planned DER projects in the Stayner area that could have been utilised to defer these upgrades. Before taking on any material capacity projects such as a substation build, EEDO would first consider if there were any planned DER or non-wires alternatives that could meet this demand. EEDO would consult with customer and development stakeholders to understand any planned investments in these areas. EEDO does not have a formal process to do this, but does has participated in the process that the OEB is currently consulting on with industry on how this type of assessment can and will be expected to be done in the future. While EEDO does expect to see continued investment in residential solar PV in its area, this investment is expected to be small and not yet at a volume of firm supply that EEDO could rely on it to meet its customer's needs.

2. Reference: Exhibit 2, Appendix A – Distribution System Plan, s. 5.4.3

Questions:

(a) Please describe how EEDO sizes new equipment to ensure it will be able to handle the future load from electrification.

EEDO Response:

EEDO's planning assumptions are explained within the DSP, section 5.3.2d. Station transformer capacity is sized to have 75% of its normal rating serving load. This is done so as to permit for load pick up from adjacent stations in event of a station outage. Feeder capacity is then limited by station transformer planning capacity. EEDO follows USF industry standards to calculate transformer sizing for residential customers.

(b) For the five largest capital spending items in the distribution system plan, please provide the following:

i. What is the approximate threshold of electric vehicle penetration (%) in the relevant area at which point an additional upgrade would be required to the proposed investment?
ii. What is the approximate threshold of the percentage of customers that electrify their fossil fuel heating with high-efficiency cold climate heat pumps in the relevant area at which point an additional upgrade would be required to the proposed investment?
iii. What is the approximate threshold of the percentage of customers that electrify both their vehicles and fossil fuel heating in the relevant area at which point an additional upgrade would be required to the proposed investment?

These questions will require a number of assumptions to be made to provide an answer. Please make and state those assumptions as necessary. To address uncertainties, please state all caveats and/or provide a range of possible figures. An order-of-magnitude answer on a best-efforts basis is sufficient.

EEDO Response:

EEDO has not undertaken an analysis of what penetration of EV or heat pumps would result in an additional upgrade requirement. EEDO feels that it is still early in the life of these technologies. Market mechanisms such as ultra-low off peak rates, and customer driven energy efficiency initiatives may result in deferring the timing of infrastructure upgrades making it difficult for EEDO to forecast this within this DSP period.

3. Reference: Exhibit 2, Appendix A – Distribution System Plan, s. 5.4.3

Questions:

(a) What percent of EEDO's customers are on restricted feeders?

EEDO Response:

EEDO interprets 'restricted feeders' to be a 'radial feed'. Approximately 5% of our customers are in this state.

(b) Please elaborate on the following statement: "EEDO has had exploratory conversations with third parties about implementing CDM solutions to reduce feeder loading during peak."

EEDO Response:

EEDO was approached by a third party group that wanted to pilot a CDM approach in Collingwood. The project concept was to combine home load management s/w with residential battery storage to be able to reduce feeder load at peak. EEDO proposed implementing this project in an area of Collingwood where the feeder was exceeding planned utilization during peak demand. EEDO's wires solution was to extend an additional feeder from the MS to split the load from the overloaded feeder. In comparing the two solution, the wires solution was approximately 5-10 times more economical at this time. Grant funding was considered to support to the CDM project, however, the third party group backed away from the project.

(c) Please provide a list of investments in the DSP that EEDO considers as potential candidates for a non-wires alternative (NWA), including CDM.

EEDO Response:

EEDO has not proposed any NWA or rate funded CDM projects. However, EEDO's investment into its GIS and SmartMap tools can be considered as enabling investments that will permit EEDO to safety and reliability connect NWA and/or CDM projects in the future. These tools are necessary in order to give EEDO the necessary real time visibility and planning capacity to interconnect solutions that will change the traditional loading patterns of the system.

(d) Will EEDO consider implementing any cost-effective NWAs prior to the expiry of its DSP in 2027?

EEDO Response:

EEDO has not included any NWA projects in its DSP.

(e) If EEDO implements an NWA in lieu of a currently-planned capital project, how would it account for the change in costs, including any migration of capital costs to operating costs?

EEDO Response:

EEDO has been involved in the OEB consultative process on this topic, and will follow the outcome.

4. Reference: Exhibit 2, Appendix A – Distribution System Plan, Page 51

Preamble:

> EEDO believes that our customer's want to continue to participate in the opportunities surrounding distributed energy resources such as electric vehicle integration and distributed renewable energy. To prepare for this grid evolution, EEDO has been implementing grid technology solutions such as a digital model of our system that permits for advanced analytics. This technology will be essential to maintain safety and reliability with the complexities introduced by EV charging behaviours and exported energy from batteries and solar PV. EEDO has developed a plan to continue to upgrade, modify and keep secure these grid technology solutions in order to maintain pace with the growing distributed energy resources.

Questions:

(a) Please describe and itemize all proposed spending to enable the implementation of DER's by EEDO's customers.
EPCOR Response:
EEDO plans to make the following investments in this DSP period pertaining to grid modernization efforts:
- ArcPro GIS upgrade and UN Migration – pls see DSP for business case
- SCADA upgrades at Stayner MS
- SCADA upgrades at Thornbury MS
- SCADA upgrades at Collingwood MS7
- Fault Line Indicators
- SCADA controlled switches

EEDO Response:

All these investments are being made to improve the visibility of our system. EV and DER penetration will change the loading behaviour by shifting load demand patterns, and creating multiple directions of load flow. This compares to the current environment of uni-directional power flow in a very predictable load pattern that is most influenced by the time of the day and the weather. Having a model that can run to assess the impacts of DER penetration will be critical to being able to optimally connect without either overbuilding the system or unnecessarily restricting the interconnection. Having real time visibility will give operators the confidence to be able to run the system as it becomes more complex overtime. These investments now are required in order to prepare for the future state of the grid.

(b) The market for DERs is rapidly changing, as are the regulatory processes and technology for connecting them to the grid. If EEDO decides between now and 2027 that additional DER-enabling investments should be made before the end of the DSP, which are not part of the proposed DSP, how would EEDO cover those costs?

EEDO Response:

EEDO believes that it is making the right investments to prepare for the grid of the future. If electrification and DER penetration occurs in an accelerated manner requiring increased infrastructure to manage the increased loading, it may warrant a midterm advanced capital module application presenting the business case justifying these additional costs should they be material in nature. EEDO does not believe that it will be the only utility facing these circumstances when they occur, and that it will be a more provincial, if not larger area scenario, not just a local issue at a specific time.

5. Reference: Exhibit 2, Appendix A – Distribution System Plan, Page 51

Preamble:

> EEDO believes that our customer's want to continue to participate in the opportunities surrounding distributed energy resources such as electric vehicle integration and distributed renewable energy. To prepare for this grid evolution, EEDO has been implementing grid technology solutions such as a digital model of our system that permits for advanced analytics. This technology will be essential to maintain safety and reliability with the complexities introduced by EV charging behaviours and exported energy from batteries and solar PV. EEDO has developed a plan to continue to upgrade, modify and keep secure these grid technology solutions in order to maintain pace with the growing distributed energy resources.

Questions:

(a) Please file a copy of any reports in EEDO's possession containing forecasts for the numbers of electric vehicles in EEDO's service area.

EEDO Response:

None available

(b) Please file a copy of any reports in EEDO's possession on the impacts of electric vehicles on (i) utility revenue and (ii) utility costs.

EEDO Response:

None available.

(c) What is EEDO's best estimates of the number and percent of electric cars in its service area total and incremental between now and 2030?

EEDO Response:

EEDO has not completed this analysis.

(d) Please describe all steps that EEDO is taking or considering to encourage customers to charge their cars at off-peak times.

EEDO Response:

EEDO continues to inform customers on potential energy savings and differences between time of use/tiered pricing and other options available. EEDO is also working to implement to proposed ultra-low TOU rate in advance of the November 2023 deadline.

(e) Please describe all steps that EEDO is taking or considering to encourage customers to use their car batteries to off-set the peak load of their building via bi-directional chargers.

EEDO Response:

EEDO has not taken any of these steps, and is not aware of any car batteries feeding into the grid.

(f) Please estimate the impact on EEDO's revenues and costs as a result of electric vehicles over 2023-2027. Please consider whether EEDO will experience additional revenues than costs as described in the following Synapse energy study: https://www.synapse-energy.com/sites/default/files/EVs-Driving-Rates-Down-8-122.pdf. Please explain the response.

EEDO Response:

The study indicates that commodity revenues from EV charging exceed the infrastructure costs. This may be true, however, commodity is a flow through for wires companies in Ontario, and the majority of residential customers are on fixed distribution rates in EEDO's area. EEDO does not expect to see a material increase in revenue to offset infrastructure costs. Infrastructure costs from the distributor's position would have to result in increased distribution rates to recover.

(g) What investments is EEDO making over 2023-2027 to accommodate an expansion of electric vehicles? Please describe these and provide the dollar total.

EEDO Response:

EEDO is not making infrastructure investments to accommodate EVs. As explained in 4 (a), EEDO is modernizing the grid to be able to handle the future of the grid, but does not have enough data to make infrastructure investments for this purpose.

(h) Does a residential customer need to notify or seek approval from EEDO before installing a high-speed electric vehicle charger? Please explain and provide any relevant excerpts from the relevant document containing said requirement.

EEDO Response:

A customer is not required to inform EEDO unless they are requiring an increase to their service.

(i) Does a residential customer need to notify or seek approval from EEDO before installing a high-speed bi-directional electric vehicle charger (under 10 kW) that does not export to the grid? Please explain and provide any relevant excerpts from the relevant document containing said requirement.

EEDO Response:

EEDO does not require a residential customer to seek approval unless it is exporting to the grid.

(j) How many applications to install bi-directional EV charges has EEDO received?

EEDO Response:

EEDO has not received any applications to date.

(k) Can EEDO require a residential customer to make a financial contribution toward distribution system upgrades necessary to allow the customer to install a high-speed one-directional EV charger? If yes, would EEDO do so? Please explain.

EEDO Response:

Potentially, depending on the financial viability of the project. This could be treated similarly to a system expansion. A major hurdle of this approach is to accurately project the load for revenue generation purposes to avoid risk for both the customer and LDC.

(l) Can EEDO require a residential customer to make a financial contribution toward distribution system upgrades necessary to allow the customer to install a high-speed bi-directional EV charger (non-exporting)? If yes, would EEDO do so? Please explain.

EEDO Response:

Potentially, depending on the financial viability of the project. This could be treated similarly to a system expansion. A major hurdle of this approach is to accurately project the load for revenue generation purposes to avoid risk for both the customer and LDC.

(m) Generally speaking, what protective devices would be needed for a residential customer to install a bi-directional EV charger that is not meant to export to the grid to ensure that there is no damage in the event of a grid outage?

EEDO Response:

Customers would need to abide by ESA standards along with LDC conditions of service and standards along with any other safety/regulatory standards. These have not been identified specifically as EEDO has not encountered this issue.

(n) Is EEDO obligated to undertake the upgrades necessary for residential customers to install EV chargers if they choose to do so?

EEDO Response:

Yes, but a customer is required to pay for upgrades beyond the basic service connection. We have not encountered a scenario where distribution assets need to be upgraded as a result of residential customer connection. There are ongoing regulatory discussions on this matter to determine who should be responsible to pay for these upgrades (i,e. should it be all customers, or only those who require EVs). This is a complicated question to answer given that the EV landscape is rapidly evolving.

(o) How many electric vehicles will EEDO buy over 2023-2027?

EEDO Response:

Uncertain at this time. EEDO is currently planning to purchase gas vehicles as included in the DSP, but will continue to monitor pricing and market trends.

(p) How many electric vehicle chargers will EEDO buy over 2023-2027?

EEDO Response:

None at this time.

6. Reference: Exhibit 2, Appendix A – Distribution System Plan, Page 51

Preamble:

> EEDO believes that our customer's want to continue to participate in the opportunities surrounding distributed energy resources such as electric vehicle integration and distributed renewable energy. To prepare for this grid evolution, EEDO has been implementing grid technology solutions such as a digital model of our system that permits for advanced analytics. This technology will be essential to maintain safety and reliability with the complexities introduced by EV charging behaviours and exported energy from batteries and solar PV. EEDO has developed a plan to continue to upgrade, modify and keep secure these grid technology solutions in order to maintain pace with the growing distributed energy resources.

Question:

(a) Please provide further details about or point to the evidence in the application that describes EEDO's plan to "upgrade, modify and keep secure these grid technology solutions in order to maintain pace with the growing distributed energy resources."

EEDO Response:

Pls see response to question 4 (a).

7. Reference: Exhibit 2, Appendix A – Distribution System Plan, Page 18

Preamble:

EEDO system losses over the historical period are shown below:

2017	2018	2019	2020	2021
5.8%	2.6%	2.6%	3.6%	3.7%

Losses have trended in the 2.6 - 6.0% range over this historical period.

Questions:

(a) Please explain why system losses fell by 2.2% between 2017 and 2018.
(b) After two years of system losses of 2.6% in 2018 and 2019, why did losses increase in 2020 and 2021 to 3.6% and 3.7%, respectively?
(c) Does EEDO quantify and consider the potential value of distribution loss reductions for different options when procuring equipment (e.g., transformers) and deciding on the details of demand-driven capital projects (e.g., the type and sizing of conductors)? If yes, please explain how and provide documentation detailing the methodology used.
(d) If EEDO is considering the value to its customers of distribution loss reductions for planning purposes, how does it calculate the dollar value ($) of said loss reductions (kWh)? Is the value calculated based only on the HOEP or on all-in cost of electricity (e.g., including the GA)?
(e) Further to the above question, Hydro Ottawa and Burlington Hydro use the all-in cost of electricity. If EEDO's practice differs, please explain whether there are aspects of its system that would justify this.

EEDO Response:

a) A revised App2-R_Loss Factors has been included with this submission. The revised total system losses are:

		Historical Years					5-Year Average
		2017	2018	2019	2020	2021	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to	307,339,771	326,491,477	320,468,420	317,162,925	325,102,769	319,313,073

	distributor (higher value)						
A(2)	"Wholesale" kWh delivered to distributor (lower value)	298,962,868	317,405,456	311,498,208	305,789,696	313,610,689	309,453,383
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	298,962,868	317,405,456	311,498,208	305,789,696	313,610,689	309,453,383
D	"Retail" kWh delivered by distributor	291,298,653	309,237,189	303,302,344	297,304,886	304,725,478	301,173,710
F	Net "Retail" kWh delivered by distributor = **D - E**	291,298,653	309,237,189	303,302,344	297,304,886	304,725,478	301,173,710
G	Loss Factor in Distributor's system = **C / F**	1.0263	1.0264	1.0270	1.0285	1.0292	1.0275
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0280	1.0286	1.0288	1.0372	1.0366	1.0319
	Total Losses						
I	Total Loss Factor = **G x H**	1.0551	1.0558	1.0566	1.0668	1.0669	1.0602

b) N/A based on the revisions above.

c) EEDO purchases equipment (e.g., transformers) to comply with current CSA requirements. CSA 227.3 and 227.4, 2.2 & 2.1-06 Standards (latest edition), and CSA 802.1 (latest edition). EPCOR also has standard conductor types and size which is dependent upon the project and loading which can be found in our Contractor Requirements and Material Specifications and as per the USF Standards (Utilities Standards Forum). Then USF Standards are used for the design of EPCOR's projects.

d) When reviewing loss impacts informally, the all-in cost would be considered (including the GA).

e) N/A based on the response to 7d.

8. Reference: Exhibit 2, Appendix A – Distribution System Plan

Questions:

For all of the below questions, please provide an answer on a best efforts basis and please make and state any assumptions and caveats as necessary.
EPCOR Response:
EEDO has not performed any studies, analysis or forecasts of heat pumps in the preparation of this DSP.

(a) Please provide any analysis that EEDO has produced or reviewed to examine heat pumps as a way to reduce distribution costs (e.g. as part of an NWA).
(b) Please complete the following table:

EEDO Customers – Characteristics by Sector			
	2022	…	2027
Total Customers			
Residential			
Commercial			
Industrial			
Customers with Electrical Space Heating			
Residential			
Commercial			
Industrial			
Annual Consumption (kWh) for Resistance Space Heating for Average Customer			
Residential			
Commercial			
Industrial			
Peak Demand (kW) for Resistance Space Heating for Average Customer			
Residential			
Commercial			
Industrial			
Annual Consumption (kWh) for Resistance Water Heating for Average Customer			

Residential			
Commercial			
Industrial			
Peak Demand (kW) for Resistance Water Heating for Average Customer			
Residential			
Commercial			
Industrial			

(c) Please complete the following table:

Electricity Use – Typical Customer After Conversion to Heat Pumps									
	Average Annual Electricity Consumption – Resistance Heating (kWh)			Average Annual Electricity Consumption (ccASHP & HPWP, HSPF Region 5=10[1]) (kWh)			Average Annual Electricity Consumption (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/ Water	Space Heating	Water Heating	Total – Space/ Water	Space Heating	Water Heating	Total – Space/ Water	Space Heating	Water Heating
Average or Typical Single-Family Residential Customer									

(d) Please complete the following table:

Winter Peak Demand – Typical Customer After Conversion to Heat Pumps									
	Average Peak Demand – Resistance Heating (kW)			Average Peak Winter Demand (ccASHP & HPWP, HSPF Region 5=10[2]) (kW)			Average Peak Winter Demand (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/ Water	Space Heating	Water Heating	Total – Space/ Water	Space Heating	Water Heating	Total – Space/ Water	Space Heating	Water Heating

[1] Equivalent to ~sCOP=2.9 (2.96516)
[2] Equivalent to ~sCOP=2.9 (2.96516)

Average or Typical Single-Family Residential Customer									

(e) Please complete the following table:

Summer Peak Demand – Typical Customer After Conversion to Heat Pumps									
	Average Peak Demand – Traditional Central AC (kW)			Average Peak Winter Demand (ccASHP & HPWP, HSPF Region 5=10[3]) (kW)			Average Peak Winter Demand (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/ Water	Space Cooling	Water Heating	Total – Space/ Water	Space Cooling	Water Heating	Total – Space/ Water	Space Cooling	Water Heating
Average or Typical Single-Family Residential Customer									

(f) Please complete this table of cooling efficiencies:

Cooling Efficiencies of Various Equipment Types			
		SEER	EER
Central air conditioners	Average of current stock (best estimate, EEDO customers or Ontario average)		
	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		
Air source heat pumps	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		
Air source heat pumps in hybrid systems (if different)	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		

[3] Equivalent to ~sCOP=2.9 (2.96516)

Ground source heat pumps – closed loop	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		
Ground source heat pumps – open loop	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		
Cold climate heat pumps – variable speed	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		

EEDO Response:

This information is not available.

EB-2022-0028

EPCOR Electricity Distribution Ontario Inc.

Responses to Small Business Utility Alliance Interrogatories

August 25, 2022

EB-2022-0028

EEDO RESPONSE TO INTERROGATORIES

OF THE

SMALL BUSINESS UTILITY ALLIANCE

SBUA 1. Exhibit 1, page 38, section 1.5. Customer Engagement.

Preamble:

In section 1.5 of Exhibit 1, EEDO described the customer engagement efforts it has undertaken since acquiring the utility in 2018. Red Head's 2021 customer satisfaction survey found that 57% of the general service business < 50 kW customer class agreed that the cost of their electricity bill has a major impact on the bottom line of their organization (compared to 37% of residential customers).

Question:

Given the critical impact of electricity bills on this customer class, please describe in detail the customer engagement efforts undertaken targeted to small businesses beyond the Red Head customer satisfaction surveys with respect to marketing, education and outreach, and provide supporting documentation.

EEDO Response:

Customer engagement activites are highlighted on App.2-AC_Customer Engagement. Sections applicable to GS<50kW customers include:

- Community Engagement - Community Events
- Community Engagement - EPCOR Heart + Soul Fund
- Customer Education - Bill Inserts, Bill Messaging
- Customer Engagement - Surveys
- Biennial Customer Satisfaction Survey - Residential and Small Business customers
- Customer Service - In-Office open to the public
- Customer Support - Financial Assistance Programs
- COVID-19 Emergency Assistance Program - Small Business (CEAP-SB)
- Conservation - Participation in conservation programs – Business

SBUA 2. Exhibit 1, Tab 2, Appendix A, page 58. Customer Satisfaction Surveys.

Preamble:

Red Head's 2021 customer satisfaction survey shows that 75% of customers in the General service < 50 kW class are net satisfied with the services provided by EPCOR, compared to 85% of the Residential class.

Question:

Please provide EEDO's views as to how to improve customer satisfaction levels amongst this group.

EEDO Response:

EEDO believes that customer satisfaction can be improved through the rollout of additional data tools (such as Green Button and a new online billing platform) to allow customers to better access and analyze data.

As GS<50kW are not demand based customers, they don't have access to the UtiliSmart Energy Manager tool that GS>50kW customers can currently use.

Customer satisfaction levels could also be improved by providing reference to commercial programs (bill relief/grants/CDM etc..) that would be applicable to this customer group.

SBUA 3. Exhibit 1, Tab 1, Page 39. Distribution Plan Customer Engagement.

Preamble:

EECO refers to a survey conducted by Stone Olafson in Q4 2021

Question:

a. Please provide a copy of the Stone Olafson report;

EEDO Response:

The report can be found in the Distribution System Plan (DSP) Appendixes (EEDO_Exhibit 2_Rate Base_20220609 Page 269 of 353).

b. How many of the 818 customers surveyed were commercial customers in the < 50 kW customer class?

EEDO Response:

10 commercial customers responded. The survey was sent to 445 commercial customers.

c. Was Stone Olafson asked to break down its findings to identify those related to this customer class specifically? If not, why not?

EEDO Response:

Please refer to the survey referenced in the DSP for a breakdown.

SBUA 4. Exhibit 7, Tab 1, Schedule 1, Page 1 and 2. Cost Allocation Weighting Factors

Preamble:

In the Weighting Factor for Services, Residential customers are given a weighting factor of 1.0 and General Service < 50 kW a weighting factor of 1.5. The explanation provided is that "[t]*he cost of General Service < 50 kW installations is somewhat higher than Residential is they may require after hours attendances to mitigate against interruptions during normal business hours. Additional time is also required to ensure the demand data is programmed and monitored appropriately.*"

Question:

a. Please provide a further explanation and all supporting documents and data to establish that services costs are proportionately 1.5 times higher for the General Service < 50 kW class than they are for the Residential class.
b. If requests for after-hours installation are driving up costs, why does EEDO consider it appropriate to have those costs borne by the entire rate class, rather than by the customers who request that service?
c. Please provide a further explanation and supporting documents and data to support the statement that "*[a]dditional time is also required to ensure the demand data is programmed and monitored appropriately*."

EEDO Response:

a) After a review of weighting factors used in its last COS proceeding and the rationale for those weighting factors, EEDO decided to maintain the 1.5 weighting factor used in that proceeding. EEDO notes that using a GS<50 kW weighting factor of 1.0 instead of 1.5 would result in no change to proposed GS<50 kW rates as the class's revenue to expense ratio is within the OEB's range of reasonableness and is not subject to revenue adjustments to maintain neutrality.

b) Requests for after-hours installation are common among GS<50 kW customers. In EEDO's view, the necessity to determine variable connection charges in excess of basic connection charges on a case by case basis for each request, as described in the OEB's Distribution System Code, would create a regulatory burden that outweighs the benefit of recovering those incremental costs from the specific customers.

c) The General Service < 50 kW customers use Commercial AMI and Commercial AMI with IT meters which requires additional time to program and monitor relative to standard AMI Meters used by Residential customers.

SBUA 5. Exhibit 7, Tab 1, Schedule 1, Page 4, Section 7.14. New Customer Class

Preamble:

EEDO states that it is not proposing to include a new customer class.

Question:

Has EEDO considered whether to include a small business customer class, which would apply to small business customers who share many of the characteristics of residential customers? If not, what is EEDO's position with respect to such a customer class?

EEDO Response:

EEDO has not considered such a rate class.

EEDO anticipates that such a rate class could lead to additional complexity in billing and reclassification in between a small business and GS>50kW customer class. In order to fairly categorize EEDO has typically relied on metered data (include both demand/consumption) for rate reclassification. EEDO would also have no way to know if a small business is operating out of a GS>50kW.

EEDO also notes a GS<50kW customer who uses consumes 750kWh of electricity monthly would only pay 7% or $9 more per month in comparison to a residenttial customer with the same usage.

A customer who operates a small business out of their home would be eligible to receive residential classification for thier small business.

Based on the analysis, EEDO does not believe the added complexity of a small business rate class will be beneficial to the overall customer base.