ESSEX POWERLINES CORPORATION

July 30, 2024

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON, M4P 1E4

Attention: Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: Essex Powerlines Corporation (Essex Powerlines) Application for 2025 Distribution Rates, Ontario Energy Board File Number: EB-2024-0022/EB-2024-0096

Please find enclosed an electric copy of Essex Powerlines' responses to OEB staff and Intervenor Interrogatories (IRR). Essex Powerlines has also included updated Cost-of-Service excel spreadsheet models and excel spreadsheets in response to some of the IRRs.

Essex Powerlines will be making a request for confidential treatment of certain information contained in the IRRs, pursuant to the OEB's Practice Direction on Confidential Filings.

Respectfully submitted,

Grace Flood, CPA, CA
Director of Finance and Regulatory Affairs
Essex Powerlines Corporation

CC: John Avdoulos, President & CEO, Essex Power Corporation
John Vellone, BLG

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OEB Staff Interrogatories

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Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from Ontario Energy Board (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 2025 Electricity Distributor Rate Applications webpage.

EPLC's Response:

The following models have been updated and are filed with interrogatory responses:

- Revenue Requirement Workform (“RRWF”)
- Filing Requirements Chapter 2 Appendices
- Cost Allocation Model
- Load Forecast Model
- DVA Continuity Schedule
- PILs Workform
- RTSR Workform

Table 1-1: Summary of Model Updates

IR Response	**Update**	**Models Updated**
2-Staff-8	2024 capital expenditures updates to reflect 6 months of actual data in 2-AA and 2-AB.	Chapter 2 Appendices, 2-AA and 2-AB
3-Staff 36	Update to the cell reference for CDM activity in the load forecast model.	Load Forecast, RRWF
4-Staff-50	Update cell reference in Appendix 2-JA	Chapter 2 Appendices, 2-JA
6-Staff-54	Update to PILs model to reflect actuals from final 2023 tax return.	PILs Workform, RRWF

6-Staff-55	Update to PILs model to correct tax smoothing related to Accelerated CAA.	PILs Workform, RRWF
7-Staff-58	Update to Cost Allocation model to correct the GS,50, GS>50 and Embedded Distributor class to reflect the number of customers times 12 on Tab 7.2 Meter Reading.	Cost Allocation Model, Bill Impact Model
8-Staff-60	Update to 2025 Load Forecast Tab 3 to reflect the latest as has been submitted as part of these IR's and corrected a data entry error on Tab 5.	Load Forecast, RRWF, Bill Impacts Model, DVA Continuity Schedule, Chapter 2 Appendices
8-Staff-61	Update to LV tab of RTSR Workform to calculate LV Rates using 2023 actual volumes and 2024 rates.	RTSR Workform, RRWF
9-Staff-63	Updates to Tab 2a, Cells C60, BW26, BW28 & BV28 of DVA Continuity Schedule.	DVA Continuity Schedule, Tariff Sheet Bill Impacts Model
9-Staff-64	Update to DVA Continuity Schedule to reflect Q3 interest rate.	DVA Continuity Schedule, Tariff Sheet Bill Impacts Model
9-Staff-67	Update to DVA Continuity Schedule to reflect final 2023 tax return and the projected 2024 addition to Account 1592	DVA Continuity Schedule, Tariff Sheet Bill Impacts Model
9-Staff-68	Update to DVA Continuity Schedule to reflect correction to disposition request for account 1576.	DVA Continuity Schedule, Tariff Sheet Bill Impacts Model
1-SEC-6	Update to Rate Riders in Bill Impact Model.	Tariff Sheet / Bill Impacts Model
9-SEC-42	Update to DVA Continuity Schedule and Table 9-17: Account 1508 Claim to update for 2024.	DVA Continuity Schedule, Tariff Sheet Bill Impacts Model
9-SEC-43	Update to DVA Continuity Schedule for Account 1535 claim.	DVA Continuity Schedule, Tariff Sheet Bill Impacts Model
5-SEC-36,5-VECC-49	Update to Appendix 2-OB to show 4 decimal places	Chapter 2 Appendices, 2-OB, RRWF

6-VECC-51	Update to Appendix 2-H 2025 values	Chapter 2 Appendices, 2-H, RRWF
7-VECC-53	Update to Cost Allocation model to correct the GS,50, GS>50 and Embedded Distributor class to reflect the number of customers times 12 on Tab 7.2 Meter Reading.	Cost Allocation Model, Bill Impact Model
7-VECC-55	Update to Cost Allocation model to correct the GS>50, the CCB and CCP values.	Cost Allocation Model, Bill Impact Model
8-VECC-58	Update to the proposed 2025 Retail Service Charges in the Tariff Schedule and Bill Impact Model to reflect the 3.6% inflation factor for 2025.	Tariff Schedule and Bill Impact Model
9-VECC-62	Update to DVA Continuity Schedule for any changes necessary based on IRs.	DVA Continuity Schedule, Tariff Sheet Bill Impacts Model
9-VECC-64	Update to DVA Continuity Schedule for Account 1535 claim.	DVA Continuity Schedule, Tariff Sheet Bill Impacts Model

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Letters of Comment

Following publication of the Notice of Application, the OEB received six 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. Please also 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.

EPLC's Response:

To address matters raised in the letters of comment, EPLC has reviewed each letter filed with the Ontario Energy Board (OEB), and identified key issues raised. Those key issues are outlined below along with responses to address the issues. EPLC will continue to monitor for additional comments or letters that are filed with the OEB and respond to any new matters accordingly.

1. Why can't General Service customers pay for any increases instead of residential customers?

EPLC operates the distribution system that delivers electricity to homes and businesses across their service territories. Resources required to achieve that distribution are analyzed and costs apportioned to the customer classes to which electricity is distributed, through the rate setting process. To maintain reliability, safety, billing accuracy and all other components of electricity distribution, costs are not assigned to only one set of customers.

2. With cost of living increases generally and many still recovering from financial impacts of the COVID-19 pandemic, rate increases would make it even more difficult financially for customers.

EPLC understands that some customers continue to be negatively affected by financial circumstances due to the cost of living and on-going impacts of the COVID-19 pandemic, and that the costs of electricity are included in those costs and those concerns.

For customers who are most impacted, EPLC continues to provide information on programs that can provide additional support such as the Low-Income Energy Assistance Program (LEAP) and its Emergency Financial Assistance program; the Ontario Energy Rebate (OER) and the Save on Energy Program. Communication to customers is essential to ensure that they are aware of and have the opportunity to take advantage of available programs and as such, EPLC communicates openly and frequently through on-bill and on-hold messaging, and EPLC's website, on this topic.

3. Has EPLC considered all opportunities for reducing costs and improving efficiency, such as paperless billing and automation of customer service activities?

EPLC has considered the resources required to operate and maintain the distribution system safely and reliably, and proposed a total bill impact of -3.79% for a residential customer and -9.91% for A GS>50 customer for January 2025 rates. These costs included in this rate calculation are those costs that EPLC requires to ensure that the distribution system meets today's needs and is ready to meet the needs of the future. Automation and efficiency are key considerations in planning at EPLC and are evidenced in the paperless billing campaign that has been rolled out and which continues to seek new participants, along with initiatives such as AI chat on the website and an automated customer service answering system to increase the number of calls that can be addressed quickly and efficiently, backed up by live personnel that are then available to attend to more specific questions.

4. How can EPLC improve reliability, even if that means investments and a fee increase?

EPLC is focused on reliability as an important customer satisfaction metric and is taking steps in the distribution system to improve reliability to customers. Specific initiatives include a broad range of smart grid devices and control room services that enable near real time outage notification and improve restoration time, along with simple cost-effective solutions like animal guards to prevent interference and investments aimed at reducing the occurrence of loss of supply outages by allowing EPLC to better control the inbound flow of electricity.

1-Staff-3

Customer Engagement
Ref 1: Exhibit 1, page 55-56
Ref 2: Exhibit 1, page 11
Ref 3: Distribution System Plan pages 15-16, 36-37, 53

Preamble:

In reference 1, Essex Powerlines states,

"The survey was conducted between November 2023 and ended early December 2023, engaging 1,874 residential and 21 general service (under 50 kW) customers. The online survey was designed to gather customer interests and use the results to support EPLC's business planning and be incorporated in its 2025-2029 Distribution System Plan"

In reference 2, Essex Powerlines states that it completed its 2024 and 2025 business plan and 2024 budget in November 2023 and these plans were approved in December 2023.

In reference 3, Essex Powerlines states that respondents indicated a preference for investing in infrastructure and/or technology to better help withstand the impacts of adverse weather including reducing the number of outages during extreme weather events (Hardening). Respondents also indicated a preference for reducing the length of time to restore power during extreme weather events (Resiliency). Essex Powerlines stated that is has, and will continue to design and invest in, storm hardening measures (i.e. physical improvements that can make utility infrastructure more resistant to weather).

Question(s):

a) Please explain how the customer engagement results specifically influenced the business plan given it had been approved prior to the survey results being available. Describe any changes made to the business plan as a result of customer feedback.
b) Please explain how customer preferences have been taken into account when planning specifically for improved reliability?
c) Were customers informed of specific investments planned for the 2025-2029 period?
d) Were customers informed of the PowerShare pilot project through these customer engagement surveys? Did Essex Powerlines conduct any specific customer engagement for the PowerShare pilot project?
e) Please detail what distribution system hardening activities are being undertaken in the DSP forecast period to address this customer preference?

EPLC's Response:

a) As per Exhibit 1, Section 1.5.3- Application- Specific Customer Engagement, EPLC holds regular customer engagement surveys to help understand customer needs and satisfaction with existing services. The feedback received from customer surveys is used to influence EPLC's priorities moving forward and is incorporated in distribution system planning efforts. EPLC conducted its bi-annual Customer Satisfaction Survey in 2021 and 2023 to canvass customer satisfaction in five key areas: power quality and reliability, price, billing and payment, communications, and customer service experience. The results from these surveys helped shape future business plans and ensure EPLC's operations are aligned with customer expectations. As mentioned in Exhibit 1, page 54, the results from the Customer Satisfaction Survey were used to inform EPLC's planning for the 2025-2029 forecast period. Customers' focus was on reliability and time to restore power. In November 2023, an additional survey was conducted to engage and inform customers on the Cost-of-Service Application, over and beyond what is typically required. The data from the survey was analyzed by EPLC's team to ensure customers' priorities were aligned with and represented in EPLC's business plan. The Rate Application was deemed to have provided sufficient evidence and detail of customer needs and preferences, which have aligned with results from previous surveys. Project prioritization was therefore not affected by the Customer Survey, as proposed projects already aligned with customer expectations.

b) Customer preferences were taken into account when planning for system reliability through various investment plans. Specifically, material projects that will increase grid reliability include EPLC's pole replacement program, OH and UG reactive replacements, infrastructure re-build program (OH/UG), metering replacements, EPLC's self-healing grid program, future proofing for DSO-related activities, implementation of a full control room and the conversion to 200A network upgrades. All of these activities provide elements that will increase the reliability and safety of EPLC's distribution system.

c) Customers were not specifically informed of investment plans for the 2025-2029 period. Customers were engaged through various surveys throughout the years to confirm an understanding of customer needs and expectations. For example, reliability and affordability were a common theme from survey outputs. As such, EPLC used these themes to guide its investment plans, and they were confirmed by the November 2023 survey.

d) The surveys described above did not specifically inform customers about PowerShare, however, customers were asked a series of questions that included questions about investing in technology to better help withstand the impact of adverse weather, enabling customers to access new electricity services, minimizing EPLC's impact on the environment, preparing the grid/infrastructure for the future, electrification, and more. The survey questions and results can be found in Exhibit 2, Attachment 2-A: Distribution System Plan (Appendix C: Customer Engagement Survey Report).
EPLC has held multiple lunch-and-learn events in each of the municipalities it serves pertaining to PowerShare. These events were open to the public. In addition, EPLC publishes PowerShare content on its social media channels and conducts public outreach on the project. EPLC has also had specific outreach to commercial customers to discuss the PowerShare project and gauge interest on potential participation and mutual benefits.

e) One of the main projects focused on system hardening includes EPLC's self-healing grid program. This program pertains to the continuation of the installation of devices that will enable real-time troubleshooting for unexpected events in the grid. The investments facilitate the incorporation of remote fault indicators, reclosers/smart switches, smart grid, renewable expansions and generation, and other associated equipment and resources required for their design, configuration, and installation within EPLC's distribution system. The Self-Healing Grid will strategically mitigate interruptions through the deployment of reclosers at key points across EPLC's distribution system, enhancing overall reliability and efficiency of the network. Smart reclosers will aid in grid hardening through the ability to operate remotely, have real-time detection, as well as the ability to isolate from an upstream distributor/transmitter.
Similarly, DSO activities will assist in system hardening by providing a balanced and stable grid. PowerShare unlocks a scalable market design to activate existing distributed energy resources (DERs) flexibility, serving as a non-wires alternative. PowerShare aims to address local constraints specific to EPLC's grid by providing flexibility that will inherently increase SAIDI/SAIFI reliability statistics.

1-Staff-4

Productivity

Question(s):

a) Please discuss if Essex Powerlines has implemented any specific productivity initiatives over the 2019-2023 period to improve cost efficiency. If productivity initiatives have been implemented, please provide details of these initiatives as well as associated cost savings (for both capital and OM&A).

b) Has Essex Powerlines planned any specific productivity initiatives for the 2024 and 2025 forecast period?

EPLC's Response:

a & b) Please find below a list of productivity initiatives that were implemented over the 2019-2023 period and/or planned for the 2024 and 2025 forecast period.

Table 1-2: Productivity Initiatives

Efficiencies / Improvements	OM&A / Capital	Effective / Planned Date	One-Time / Persistent Cost Savings or Avoided Cost	Calculations / Assumptions
Installation of Reclosers	Capital OM&A	2019-existing	Persistent One-Time	- Reduced costs-can be operated from the ground with one Maintainer. Assuming 20-25 operations/year with truck and second person ~$16k - Reduced risk of accident/injury. - When operated remotely savings increase $30k ofsetting cost of Control Room operation. - Improved SAIDI/SAFI when operated as FLISR - Grid flexibility/resilience - Realtime network monitoring - Since 2019, Maintenance cost equivalent to 3 Maintainers + 2 bucket trucks for 8 hours at Maintainer rate. ~ $2240/unit installed.
Replacement/Upgrade of PMH units with MVI units	Capital	2019-2022	Persistent	- Reduced costs associated with operation of unit - can be done with one Maintainer. Assuming 20-25 operations/year with second person~$8k - Reduced risk of accident/injury. - Availability of realtime network monitoring
Comissioning of Distribution Automation Controller (DAC)	Capital	2023-2025	Persistent	- Working in conjunction with Control Room to monitor network loading and suggest switching configurations. Ultimate goal is to have the controller execute switching operations. - Estimated reduction of $100k in manual switching once fully operational.
Implementation of Aerial Drone inspections	OM&A	2022-existing	Avoided Cost	- Estimating reduction in reactive/emergency work due to failed/damaged wood poles and devices. Aerial inspection can detect top rot, loose hardware, and insulator tracking which is near impossible to see through normal inspection methods. ~ $30-40k
Control Room	OM&A	2024-existing	Persistent	- Estimating reduced call-outs and time scouting for source of outage $20k. - Significant reduction in SAIDI - Improved planning process yielding greater efficiency in work execution - Potential to reduce Loss of Supply events
Position Shared Cost - Cyber Security Supervisor	OM&A	2025	Avoided Cost	Exploring the idea of shared resource with like minded LDC. Estimated cost avoidance of $30,000
Work Centre - DJP	OM&A	2024-existing	Avoided Cost	Estimated $32,851 in avoided cost for 2024 YTD as new hire is avoided. Customer Service staff is able to support the OPS department through use of the DJP software.
Phone System - Online AI Chat Bot	OM&A	2023-existing	Avoided Cost	Estimated $4,007.10 in avoided cost YTD. Based on 3335 online chat interactions avoiding an estimated 2 minutes of CSR time per interaction.
Phone System - IVR Module -Collections	OM&A	2022-existing	Avoided Cost	Estimated $13,802 in avoided cost YTD. Based on 2022-2024 where IVR was used instead of making phone calls to customers. There were 55 days of one FTE CSR avoided. Estimated 7 hours per day x CSR rate.
Phone System - IVR Module - Planned Outage Comm	OM&A	2023-existing	Avoided Cost	Estimated $17,702.50 in avoided cost YTD. Based on 194 planned outages over 2023/2024 where IVR was used instead of sending out staff to deliver notices. Estimated 2.5 hours per outage at utility laborer rates.
Harris Automation	OM&A	2021-existing	Persistent	Estimated $16,500 in savings over last three years. 157 CSR hours annually freed up to support other departmental.
Work Center - WSJC Module	OM&A	2020-existing	Avoided Cost	Estimated $28,800 in avoided cost YTD. This is based on GP software license costs of $480 annually x 12 users YTD.
Work Center - Job Close Module	OM&A	2020-existing	Persistent	Estimated $16,800 in savings YTD. The software offers ongoing savings of an estimated 8 hours per month of finance staff and 8 hours of OPS/Eng staff per month YTD.
E-Billing	OM&A	2019-existing	Persistent	Calculations were done based on assumption of each customer receives one bill per month. Estimated savings by year: 2019 - $89,722 (6,923 accounts) 2020- $127,458 (9,656 accounts) 2021-$143,140 (10,844 accounts) 2022-$144,315 (10,953 accounts) 2023-$155,786 (11,802 accounts) 2024-$83,199 (11,954 accounts) includes stock cost, postage cost less rendering cost.
Website Upgrade - OMS communication	OM&A	2019-existing	Avoided Cost	Estimated $15,000 in savings. 34,945 customers effected by planned outages since 2019. It was estimated to have avoided 1,700 potential customer calls during the day @10 min per call as communication was available through website enhancements.

1-Staff-5

DSO Activities

Ref 1: Exhibit 1, Business Plan, page 6

Ref 2: OEB Innovation Sandbox Guidance DSO Pilot Project

Preamble:

In reference 1, Essex Powerlines states,

"A new category, called DSO Activities, highlights the additional costs to incorporate EPLC's transition to a Distribution System Operator (DSO). It is important to note that monetizing this transition is still in the investigation stage. Even though the OEB has provided direction that these costs fall under distribution activities and can be captured in rates, the debate as to who the beneficiary is and who should ultimately pay is not fully understood."

Question(s):

a) Please clarify the OEB direction from reference 1 and if it is referring to the OEB Innovation Sandbox Guidance for Essex Powerlines Corporation containing the OEB's staff view on the PowerShare DSO Pilot Project (reference 2).

EPLC's Response:

a) EPLC confirms that the reference in Exhibit 1, Business Plan, page 6, is a reference to the OEB Innovation Sandbox Guidance that EPLC received in a letter dated May 31, 2022, and which has been filed via RESS as "OEB Innovation Sandbox Guidance DSO Pilot Project_20240621".

1-Staff-6

DSO Activities
Ref 1: Exhibit 2, Distribution System Plan, page 74
Ref 2: Undertaking Response JT1.5, Appendix B, GIF Contribution Agreement, page 13
Ref 3: Distribution System Plan – Appendix A: Material Investment Narratives pages 90-99

Preamble:

In reference 1, Essex Powerlines states,

"To achieve a fully functional DSO, prudent system investments need to be made for a successful transition. These investments are necessary for grid modernization and to meet customer expectations of a reliable and affordable grid, but also have the added benefit of helping achieve DSO readiness. These projects are incorporated in EPLC's distribution system plan under the system service category and are relevant for EPLC's everyday operations."

Question(s):

a) Please clarify which specific system investments (with reference to relevant material investment narratives) this statement applies to.
b) Which, if any, of these system investments are funded in full or in part by Essex Powerlines total contribution to the PowerShare DSO pilot project (the $1,148,598.10 quoted in reference 2)?
c) Is the IESO contributing 50% towards these system investments as part of the Grid Innovation Fund (GIF) Contribution Agreement for the PowerShare DSO pilot project?

d) If Essex Powerlines does not proceed with the DSO pilot project, will it still undertake these grid modernization investments? If yes, how will these investments be impacted, if GIF funds are no longer available to make those investments?

e) Are the system investments being made solely to advance the DSO pilot?
   a. If so, are they necessary to i) meet an identifiable, forecasted system need in the near term, or ii) to inform whether the technologies being piloted can be adopted to meet a future system need, when such a system need materializes in the future? Please explain.

f) For the PowerShare DSO pilot project (material investment narrative 5.34), what are the specific capital assets covered by the 2025 – 2029 forecast year expenditures, and why does project spending extend beyond the Pilot Project's end date of March 31, 2026?

EPLC's Response:

a) This statement applies to assets defined within the Material Narratives EPLCSS – Self Healing Grid and EPLCSS – Metering Replacements.

b) None of these investments are funded in full or in part by EPLC's total contribution to the PowerShare DSO pilot Project. They are separate projects that support overall grid modernization and DSO adoption as a strategy to address future needs.

c) No, the IESO is not contributing 50% toward these system investments as part of the Grid Innovation Fund (GIF) Contribution Agreement for the PowerShare DSO pilot Project.

d) Yes, if EPLC does not proceed with the DSO pilot, these system investments will still be made. These investments will not be impacted by GIF funding as these investments are not funded by the GIF.

e) No, these system investments are not being made solely to advance the DSO pilot. These activities as described in a), are an innovative way to meet customer demand while maintaining a clean, reliable, and affordable energy system for the future.

f) For the PowerShare DSO Pilot, the specific capital assets include metering elements and associated connection hardware (wire, cable, poles, transformers etc.). Project spending continues beyond the Pilot Project's end date as EPLC believes that the DSO transition is the next evolution for an LDC as part of and to support a regional or provincial energy market.

1-Staff-7

Activity and Program-based benchmarking
Ref 1: Exhibit 1, 1.6.7, page 69-73
Ref 2: Benchmarking Update Calculations (xlsx)

Preamble:

In reference 1, Table 1-21 to 1-27 provides a summary of the Activity and Program Benchmarking unit cost results. Based on the year-over year calculations, OEB staff would like to inquire about the observed trends.

Question(s):

a) In reference to Table 1-21: Billing O&M per Customer Benchmarking, please provide an explanation of the factors that led to the 13% increase in 2022 compared to 2021 and the 14% increase in 2020 compared to 2019.

b) In reference to Table 1-22: Metering O&M per Customer Benchmarking, please explain:
    i. The factors that led to 16% increase in metering O&M per customer unit cost observed in 2022.
    ii. The current backlog in Metering O&M, and how is it impacting operational efficiency and customer service delivery?

c) In reference to, Table 1-23: Vegetation Management O&M Benchmarking, please explain:
    i. Why the vegetation O&M unit cost is above the industry average. Are there any specific cost categories (labor, material, trucking, other expenses) that tend to be significant drivers of this higher cost?
    ii. What factors led to the increase of 14% in 2022 compared to 2021?
    iii. While Table 1-23 values were updated from Cost ($1000) to Unit Cost ($/pole), the column name within the table has not been updated to reflect this change. Please update the column name to accurately reflect the unit cost values.

d) In reference to Table 1-24: Lines O&M Benchmarking, OEB staff noticed that the values that were provided as lines O&M cost instead of Unit Cost ($/Circuit km of Primary Line). Please provide the unit cost for this metric in the table below.

Distributor	**Table 1-24: Lines O&M Benchmarking**				
	Lines O&M Cost ($/Circuit km of Primary Line)				
	2019	2020	2021	2022	Average
Essex Powerlines Corporation					

e) In lieu of the unit cost metrics, OEB staff has conducted a year-over-year analysis using the Benchmarking Update Calculations (xlsx) and APB Unit Cost Calculations: 2023 Results (xlsx) - 27 March 2023 (Reference 2). Please provide details on the specific factors that led to the 45% increase in Lines O&M costs in 2022 compared to 2021.

f) In reference to Table 1-25: Poles, Towers O&M Benchmarking, please explain the 166% increase in Poles, Towers O&M costs from 2018 to 2019, and the 196% increase from 2021 to 2022. What challenges or factors contributed to these significant increases, and what measures are in place to mitigate such fluctuations in the future?

g) In reference to Table 1-25: Poles, Towers O&M Benchmarking, please elaborate on the factors that contributed to the 9% increase in Lines O&M costs from 2020 to 2021? Additionally, please provide a detailed explanation for the 45% increase in Lines O&M costs observed in 2022 compared to 2021.

h) While Table 1-25 values were updated from Cost ($1000) to Unit Cost ($/Pole), the column name within the table has not been updated to reflect this change. Please update the column name to accurately reflect the unit cost values.

i) In reference to Table 1-26: Poles Capex Unit Cost Benchmarking, what specific factors contributed to the significant increases in poles and towers CAPEX, with a 49% rise from 2019 to 2020 and a 28% rise from 2021 to 2022.

j) In reference to Table 1-27, what specific factors contributed to the increases in Line Transformer CAPEX, with rises of 26% from 2018 to 2019, 23% from 2020 to 2021, and 57% from 2021 to 2022? Please provide details on major projects, market conditions, or strategic decisions that drove these increases, particularly focusing on the costs of labor, materials, and expenses incurred in the maintenance and upgrade of overhead and underground distribution line transformers, as well as pole-type and underground voltage regulators owned by the utility.

EPLC's Response:

a) In reference to Table 1-21: Billing O&M per Customer Benchmarking, EPLC has no specific insights into the cause of fluctuations in 2022 compared to 2021 and in 2020 compared to 2019. The years in question cover the onset and exit of the Covid-19 pandemic period, which may have had an impact on variability of costs. EPLC's average is slightly below the industry average and is almost equal to the average of the benchmarked cohort.

b) In reference to Table 1-22: Metering O&M per Customer Benchmarking,
   i. The 16% increase in metering O&M per customer unit cost observed in 2022 is the result of increased metering operations work coming out of the pandemic.
   ii. The backlog in Metering O&M has been recovered and there is no ongoing impact on operational efficiency and customer service delivery.

c) In reference to, Table 1-23: Vegetation Management O&M Benchmarking,
   i. EPLC currently does not have insights as to why their Vegetation Management costs are slightly (4.8%) higher than the industry average. Factors that contribute to this cost include size of service area, km of line running through heavy forestry areas, and the overall Vegetation Management Plan of the Utility. EPLC for many years has understood the importance of Vegetation Management and has maintained a consistent plan to avoid unplanned tree trimming costs and improved reliability.
   ii. The increase of 14% in 2022 compared to 2021 shows a return to prior year costs in this category and appears to reflect a recovery from a slight reduction in vegetation management activity during the COVID-19 pandemic.
   iii. Table 1-23 is resubmitted below with the corrected title showing 'Unit Cost ($/Pole)'.

Table 1-3: Re-submission of Table 1-23 from Exhibit 1

	Vegetation Management O&M Unit Cost ($/Pole)					
	2018	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$18.04	$15.45	$11.61	$15.63	$23.65	$16.88
E.L.K. Energy Inc.	$18.09	$16.38	$14.36	$38.65	$78.23	$33.14
Entegrus Powerlines Inc.	$13.96	$13.09	$5.61	$9.51	$22.03	$12.84
EnWin Utilities Ltd.	$46.88	$51.03	$49.39	$60.16	$49.22	$51.34
ERTH Power Corporation	$19.45	$13.66	$14.42	$15.06	$18.99	$16.32
Essex Powerlines Corporation	$76.33	$73.86	$64.42	$65.54	$75.00	$71.03
Westario Power Inc.	$12.11	$14.86	$30.50	$26.40	$35.66	$23.91

d) The metric for $/Circuit km of Line is shown in the table below.

Table 1-4: Lines O&M Benchmarking

Table 1-24: Lines O&M Benchmarking

Distributor		Unit Cost ($/Circuit km of Primary Line)				
		2019	2020	2021	2022	Average
Essex Powerlines Corporation		1,706.36	1,631.14	1,780.81	2,574.45	1,706.10

e) The 45% increase in Lines O&M costs in 2022 compared to 2021 can be attributed to additional labour and equipment costs. In 2022, EPLC hired two additional line maintainers in preparation for two pending retirements, and also added an apprentice line maintainer to support the future needs of the utility. EPLC also piloted a trial project of aerial inspections of some assets using drone technology in 2022.

f) In reference to Table 1-25: Poles, Towers O&M Benchmarking, the large percentage increases between 2018 and 2019 and 2021 and 2022 are due to pole inspections conducted in 2019 and 2022. The type and quantity of poles tested varies year over year. Concrete poles are visually inspected and wood poles are drill tested on a 3-year cycle as mandated by the OEB.

g) Please see response to part e) above for the 45% increase in Lines O&M costs in 2022 compared to 2021.The increase of 9% from 2020 to 2021 is attributed to increased costs necessitated during the pandemic to maintain crew safety and working conditions in order to comply with the province's health mandates.

h) Table 1-25 is resubmitted below with the corrected title showing 'Unit Cost ($/Pole)'.

Table 1-5: Resubmission of Table 1-25 from Exhibit 1

	Poles, Towers O&M Unit Cost ($/Pole)					
	2018	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$0.36	$0.76	$0.43	$0.50	$0.21	$0.55
E.L.K. Energy Inc.	$7.26	$9.12	$8.63	$12.26	$20.93	$9.45
Entegrus Powerlines Inc.	$2.99	$7.36	$5.18	$5.77	$8.03	$5.22
EnWin Utilities Ltd.	$27.63	$28.15	$45.40	$48.84	$52.93	$37.50
ERTH Power Corporation	$7.06	$7.09	$6.45	$6.59	$8.39	$6.82
Essex Powerlines Corporation	$5.14	$13.66	$12.75	$5.29	$15.68	$9.97

i) In references to Table 1-26: Poles Capex Unit Cost Benchmarking, the increases of 49% in 2020 compared to 2019 and 28% in 2022 compared to 2021, are due to a lower quantity of pole testing and replacement activities in years where costs per unit are lower.

j) In reference to Table 1-27: Line Transformer Capex, the increases of 26% in 2019 compared to 2018, 23% in 2021 compared to 2020 and 57% in 2022 compared to 2021 are the result of material cost increases and increases in required transformer replacements based on both proactive and reactive work. EPLC does not own any pole mounted or underground voltage regulation installations. Some Major projects are listed as follows:

   i. 2019 – no abnormal market conditions. Material cost and delivery is on par with historical increases. Item #3 and #4 were planned for 2018 and deferred due to unanticipated activity in developments/new connections.
      1. St.Thomas/McNorton install 12 TXs & 6 peds, new primary, remove 18 TXs
      2. Mcgaw new primary, install 4 TX remove 5 TX, add 3 phase loop
      3. Amherstburg 4kV Main St. North West conversion to 27.6kV – new primary, secondary buss, new service conductors and 3 TX's

        4. Dalton/Oxley/9th concession OH to UG backyard Conversion, new primary, all OH services converted to ug, 8 TX's

    ii. 2020 – COVID-19 impacted many developers/contractors and EPLC was able to capitalize on much lower contractor costs. EPLC also experienced a reduced efficiency in work execution due to the separation of crews. EPLC was notified by manufacturers that transformer costs will be revised as supply chain gaps began.
        1. Amberly UG rebuild new primary, 4TXs with 2TXs & 2 peds
        2. Dorset/Collier UG rebuild new primary, 18TX with 13 TXs & 5 peds
        3. Estate Park UG rebuild remove 14 and install 9 new TXs & 5 peds
        4. Kimberly UG rebuild remove 11TX and install 7TX & 4 peds
    iii. 2021 – COVID-19 was still having an impact on contractors, however materials were becoming scarce as gaps in the supply chain increased. EPLC also started to see significant increases in asset costs. Transformer pricing was increasing every three months. EPLC made a strategic decision to order transformers for future work to ensure they would be available when needed. The separation of crews continued to drive lower efficiencies in work execution.
        1. Gauthier/Evergreen UG rebuild, new primary, remove 9 TX install 7 TX & 2 peds
        2. Valente Oliver UG rebuild, new primary remove 14 TX, install 9 TX & 5 peds
        3. Michael Keith UG rebuild, new primary, remove 11TX, install 7 TX & 4 peds.
        4. Sprucewood OH 3-phase line rebuild 6 TX replaced
        5. Broderick OH 1-phase line rebuild 9 TXs replaced
    iv. 2022 – Supply chain was not fully recovered and EPLC was unable to obtain any pole mounted transformers and deferred most planned work related to OH rebuilds and TX replacements to ensure transformer stock for customer and reactive work was maintained. Transformer costs were still increasing with growing delays on delivery.
        1. St Pierre 3-phase pole line rebuild, new primary, 8 TX replaced
        2. Village Grove UG rebuild, new primary – remove 7 elbow manual switching pedestals.
        3. Dillon Wedgewood UG rebuild, new primary remove 19 TX install 15 TX & 4 peds.
        4. Rushwood UG rebuild Phase 1, new primary remove 14 TX, install 13 TX & 1 ped.

School Energy Coalition (SEC)

1-SEC-1

[Ex. 1, p. 23] Essex is currently negotiating a new union contract and has used a 2% annual increase as a placeholder.

a) Please provide an update on the negotiations.
b) What are Essex's intentions with respect to adjusting the placeholder should the contract be finalized during this proceeding?

EPLC's Response:

a) See response to 4-Staff-39.
b) See response to 4-Staff-39.

1-SEC-2

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

EPLC's Response:

EPLC has not undertaken benchmarking studies, reports or analyses that are not already included in the Application.

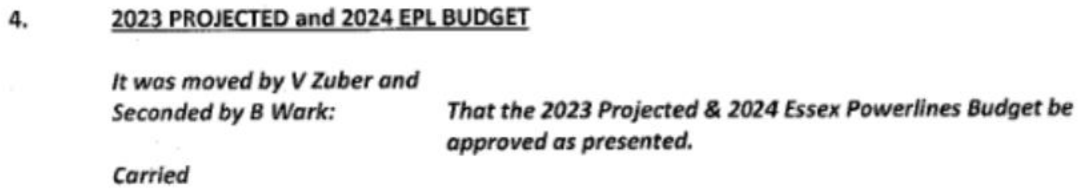
1-SEC-3

[Ex. 1, Attachment 1-A EPLC 2024-2025 Business Plan and Appendix 2-AB] Essex has provided a copy of its Business Plan, which was approved by its Board on December 6, 2023.

a) Page 5 of the Business Plan states that "spending for 2023 and 2024 has been planned to match pace with the previous DSP". Please explain this statement given that the average Capex from 2018 to 2022 was $5,547k and the Capex in 2023 was $7,679k and forecasted to be $9,308k in 2024 in 2-AB.
b) Please explain the differences between the capital numbers shown in the Business Plan and those shown in 2-AB for 2022 to 2024.
c) Were the increases in capital from the plan to the Application for 2024 approved by the Board? If so, please provide copies of any related documents.
d) What 2025 budget was presented to the Board? Please provide copies of any documents where the Cost of Service application budget was discussed and/or approved by the Board.
e) Please provide any other materials provided to Essex's Board of Directors regarding its approval of the Application and the underlying budgets.

EPLC's Response:

a) The proposed spending in the categories System Access and System Renewal match pace with historical spending. As stated in the business plan, System Service spending has increased due to the opportunity of the NRCan Smart Renewables and Electrification Pathways Program (SREPP) and the Independent Electricity System Operator (IESO) Grid Innovation Fund DSO Pilot Project. In System Service, EPLC increased spending to accelerate the installation of smart devices with a goal to improve network resiliency, add flexibility, reduce outages for its customers, and to better understand how a DSO model with an energy market could support a need locally, regionally and potentially provincially.
b) The Capital expenditures depicted in the Business Plan page 5 do not include the General Plant category and the 2023 actual is represented to November 15th 2023.
c) The Board approved the 2024 budget which reflected the capital amounts included in the Application. From the Meeting minutes of the December 7, 2023 board meeting:



4. **2023 PROJECTED and 2024 EPL BUDGET**

It was moved by V Zuber and Seconded by B Wark: *That the 2023 Projected & 2024 Essex Powerlines Budget be approved as presented.*

Carried

The 2024 budget that was presented at the meeting is attached here as Attachment A.

d) The 2025 Budget was discussed at the December 7, 2023 as part of the Regulatory report to the Board following the review of the Business Plan. Subsequently at the April 2024 Board meeting a full discussion of the Revenue Requirements and projected bill impacts to customers took place as a follow up to the Regulatory Report per the following:

BOARD OF DIRECTORS MEETING MINUTES

Thursday, April 18 2:00 pm, Blackacre

4. **REGULATORY REPORT**

Received as an information item

e) Answers to sections c) and d) above comprise the communications with the Board regarding the Application. The EPLC Board is active and engaged on the Application, its impacts and the process; Board meetings included discussion on these topics.

1-SEC-4

[Ex. 1] Please provide details of all productivity and efficiency measures Essex has undertaken over the last five years and any it plans to undertake in the test year and subsequent four years. Please quantify the forecasted savings and explain how they were calculated.

EPLC's Response:

Please see 2-Staff-10.

1-SEC-5

[Ex. 1, Scorecard] Please file on the record Essex's preliminary scorecard for 2023.

EPLC's Response:

EPLC's preliminary 2023 scorecard is attached as Attachment B.

1-SEC-6

[Ex. 1, Table 1-12]

a) The bill impacts shown for 'Distribution Bill Impact %' do not agree with the Bill Impact spreadsheet Tab 6. Please provide the correct numbers.
b) Tab 4 of the Bill Impact spreadsheet has incorrect designations (e.g. Sub-total A or B for the Group 2 DVA accounts). Please confirm that the correct sub-total is specified for all Rate Riders and update impacts as required.

EPLC's Response:

a. The numbers in the Bill Impact model were updated on the 20240517 version submitted after OEB Staff identified an error in the Tariff Schedule and Bill Impact Model where the Additional Rates for the Embedded Distributor Service Classification were not being populated in Tab 5- Final Tariff Schedule and Tab 6 -Bill Impacts tab. The numbers in that submission are correct.

b. EPLC has reviewed the Bill Impact spreadsheet and among other changes, has confirmed that the correct subtotal is specified for all Rate Riders and has updated the Bill Impact model accordingly.

1-SEC-7

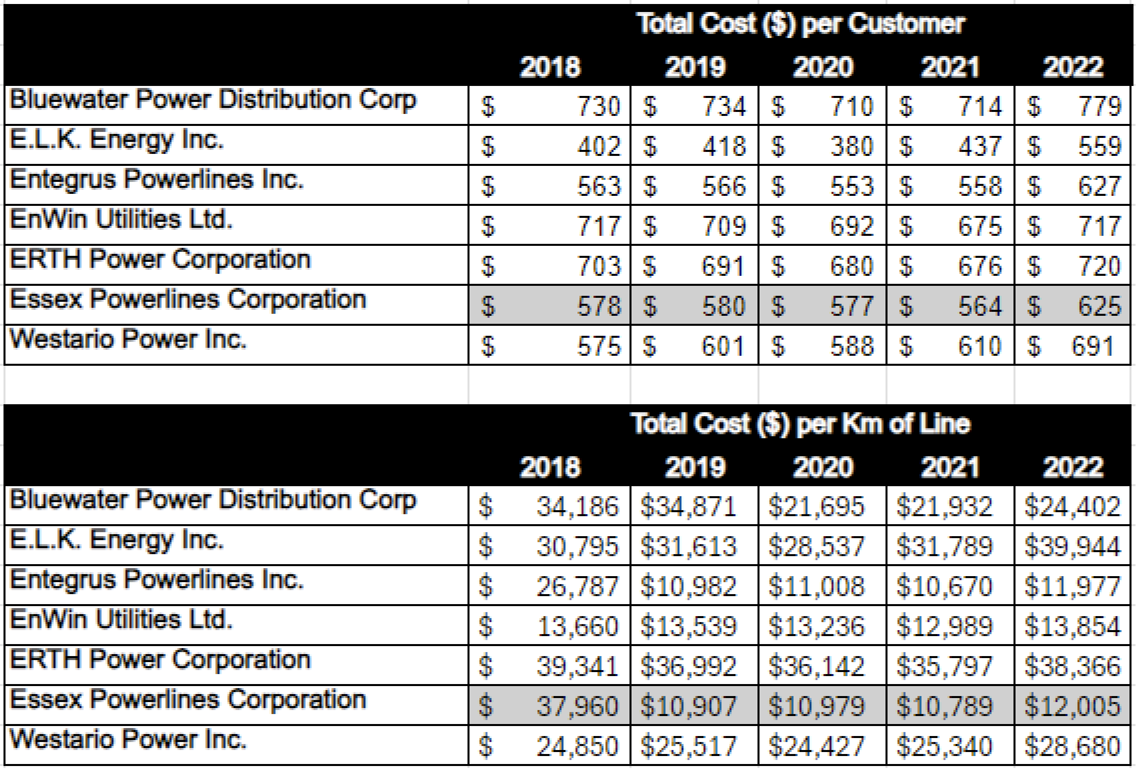
[Ex. 1, Tables 1-19, 1-20 and 1-23]

a) Please explain the high Total Cost ($) per Km of Line in 2018 and 2019 and the drop in 2020 in Table 1-20 and reconcile with Table 1-19.
b) Please provide a further explanation about why Essex's Vegetation Management O&M costs are so much higher than its peers.

EPLC's Response:

a) EPLC notes that there were data entry errors in Table 1-20 which have been corrected and are shown below which now reconciles with Table 1–19.

Table 1-6: Resubmission of Table 1-20 in Exhibit 1



	Total Cost ($) per Customer				
	2018	2019	2020	2021	2022
Bluewater Power Distribution Corp	$ 730	$ 734	$ 710	$ 714	$ 779
E.L.K. Energy Inc.	$ 402	$ 418	$ 380	$ 437	$ 559
Entegrus Powerlines Inc.	$ 563	$ 566	$ 553	$ 558	$ 627
EnWin Utilities Ltd.	$ 717	$ 709	$ 692	$ 675	$ 717
ERTH Power Corporation	$ 703	$ 691	$ 680	$ 676	$ 720
Essex Powerlines Corporation	$ 578	$ 580	$ 577	$ 564	$ 625
Westario Power Inc.	$ 575	$ 601	$ 588	$ 610	$ 691

	Total Cost ($) per Km of Line				
	2018	2019	2020	2021	2022
Bluewater Power Distribution Corp	$ 34,186	$34,871	$21,695	$21,932	$24,402
E.L.K. Energy Inc.	$ 30,795	$31,613	$28,537	$31,789	$39,944
Entegrus Powerlines Inc.	$ 26,787	$10,982	$11,008	$10,670	$11,977
EnWin Utilities Ltd.	$ 13,660	$13,539	$13,236	$12,989	$13,854
ERTH Power Corporation	$ 39,341	$36,992	$36,142	$35,797	$38,366
Essex Powerlines Corporation	$ 37,960	$10,907	$10,979	$10,789	$12,005
Westario Power Inc.	$ 24,850	$25,517	$24,427	$25,340	$28,680

The drop in cost per km of line from 2018 to 2019 was due to a change in reporting. OEB 2.1.5.5 e - Circuit kilometers of Line was provided to ensure all Distributors were reporting consistently. The reduction was due to the clarification of calculating the line by circuit km of line instead of km of line. i.e. in 2018 a 3PH primary line was measured with km in mind and not circuit km's. A 100km, 3PH primary line that was reported should have been reported as 300km (3phases x km). The above Table shows a similar change for Entegrus Powerlines Inc.

b) EPLC's Vegetation Management costs may be higher than its peers because of various contributing factors that differentiate each LDC, some of which are size of service area, percentage of urban vs rural, km of line that run through heavy forestry areas, and the overall Vegetation Management Plan of the Utility. EPLC understands the importance of proper Vegetation Management and is diligent in staying current with their established plan to provide value in reducing unplanned tree trimming costs and improved reliability.

1-SEC-8

[Ex. 1, Figure 1-2] Please confirm that all positions shown are in the regulated company. If not, please provide which company each position is a part of.

EPLC's Response:

The organizational structure depicted in Exhibit 1, Figure 1-2 exhibits executive and senior management positions. All positions aside from the President & Chief Executive Officer are held in the regulated company. To clarify, this includes the General Manager, Director of Operations, Director of Engineering and Assets, Director of Customer Experience, Corporate Services Manager, IT Manager, and the Director of Finance and Regulatory Affairs.

1-SEC-9

[Ex. 1, p. 56] How has Essex engaged its customers in the GS > 50 kW class? Specifically what changes, if any, were made to the 2025 budget as a result of customer engagement.

EPLC's Response:

EPLC engaged Innovative Research Group to conduct an online survey seeking customers' input on their interests, needs, and priorities as it relates to EPLC's business operations. The survey was conducted through an email campaign, as well as site-wide notifications on the EPLC website. Customers in the GS>50kW class did not respond to the survey. EPLC has ad hoc meetings with GS>50kW customers when a need arises. During the planning period, meetings with GS>50kW were conducted to discuss planned expansions, which were used to influence EPLC's load forecast and taken into consideration when planning for infrastructure upgrades to ensure EPLC has enough capacity to maintain a safe and reliable grid.

1-SEC-10

[Ex. 1, p. 65] Essex states that it is committed to maintaining its current efficiency ranking of Cohort 1, yet forecasts moving to Cohort 2 because of this Application. Please explain how Essex determined that it would accept moving to Cohort 2.

EPLC's Response:

EPLC does remain committed to maintaining efficiency and also acknowledges that some increase in spending is and will be necessary to support grid modernization and digitalization of electricity distribution activities. The calculation undertaken that shows a move back to Cohort 2, shows that EPLC is just outside the 25% mark under predicted costs (at 22.5%) that would keep the utility in Cohort 1.

1-SEC-11

[Ex. 1, p. 58] Does Essex have a corporate scorecard or similar document used by its Board of Directors to monitor and measure performance? If so, please provide a copy of each annual document from 2018.

EPLC's Response:

EPLC does not produce a corporate scorecard.

Vulnerable Energy Consumers Coalition (VECC)

1-VECC-1

Reference: Exhibit 1, page 18

"*These plans include acquisition of assets from Hydro One Networks Inc. that will improve reliability, by permitting EPLC to better manage its access to power and reduce loss of supply occurrences that continue to be the main cause of outages and reduce reliability to EPLC's customer base. Specifically, these assets are sections of the Malden M& (in Amherstburg) and sections of the Leamington M24 and M27*"

When are the above investments expected to occur and what is the expected cost?

EPLC's Response:

a. The HONI asset purchases are planned for late 2024, 2025, 2026 and 2027. EPLC has visually inspected these assets and is estimating these costs to total $2,735,913 over the four years.

1-VECC-2

Reference: Exhibit 1, page 59 / Attachment 1-C

a. Please update the Essex OEB Scorecard to include 2023 results.

EPLC's Response:

a. See response to 1-SEC-5.

1-VECC-3

Reference: Exhibit 1, page 62

a. Given that loss of supply makes up such a large portion of EPLC outages (50%+) what specific efforts has the Utility made to work with Hydro One to minimize supply outages?
b. Does EPLC meet regularly to address supply issues? If so are action notes/plans made as a result of those meetings?

EPLC's Response:

a. As EPLC is an embedded distributor within the Hydro One distribution network, EPLC has engaged with Hydro One to better understand why these outages occur. Further, EPLC studies its internal network to see if there are opportunities to quickly isolate the feeder that is out and transfer some or all of this load to an active feeder. To this end, EPLC provides detailed load transfer options to Hydro One so that they can perform studies to understand the impact of these load transfer options on a larger scale. This information exchange and study activity is completed on an annual basis to ensure the most up to date information is available to make decisions.
b. Yes, EPLC and Hydro One Networks typically meet every few months to discuss supply issues and other potential concerns and to coordinate activities. For supply outages, in some cases, Hydro One is able to identify the root cause of the outage and provide a corrective action or plan to mitigate a similar occurrence in the future. As part of these discussions and as outlined in a), EPLC and HONI are working to coordinate load transfers when a Loss of Supply event occurs. In the course of these discussions, issues and actions are recorded in a shared document.

1-VECC-4

Reference: Exhibit 1, Attachment 1-A

a. When was the 2024-2025 Business Plan finalized?

EPLC's Response:

EPLC finalized the 2024-2025 Business Plan in December 2023.

1-VECC-5

Reference: Exhibit 1, Attachment 1-H

a. Was the entire cost of the Innovative Research Group (IRG) customer survey $22,500?
b. What specific questions were asked in the survey with respect to the PowerShare project?
c. Were customers in the survey given any specific information with respect to the PowerShare or any other NRC or IESO co-funded projects? Specifically, were customers told that they may be contributing toward pilot projects and how much?

EPLC's Response:

a. The entire cost of the Innovative Research Group customer survey was $22,500.
b. Please refer to 1-Staff-3 Part d.
c. Customers were not given specific information on PowerShare or any other NRCan or IESO co-funded projects through the survey. EPLC has held multiple lunch-and-learn events in each of the municipalities it serves pertaining to PowerShare. These events were open to the public. In addition, EPLC publishes PowerShare content on its social media channels and conducts public outreach on the project. EPLC has also had specific outreach to commercial customers to discuss the PowerShare project and gauge interest on potential participation and mutual benefits. Customers were not specifically told that they may be contributing toward the PowerShare pilot project.

Exhibit 2- Rate Base

OEB Staff Interrogatories

2-Staff-8

2024 Bridge Year Actual
Ref 1: Appendix 2-AA and Appendix 2-AB

Question(s):

a) Please update capital expenditures for 2024 bridge year in Appendix 2-AA format and Appendix 2-AB format (and update other related tabs in Chapter 2 Appendices accordingly) for the latest actuals. Please specify for which months actual data has been used and which months are forecast data.

EPLC's Response:

a) Capital expenditures for 2024 bridge year are updated in Appendix – 2-AA and Appendix 2-AB in file 'EPLC_Chapter2Appendices_IRR_20240730.xlsm. This data is actual to June 30th; the total year budget remains the same and therefore any remaining amount from actual to budget is forecast.

2-Staff-9

5.2.1 Distribution System Plan Overview
Ref 1: Distribution System Plan pages 2, 14 and 81
Ref 2: Exhibit 4, page 28

Preamble:
Essex Powerlines states that to achieve the objectives of its five-year plan it will continue to expand Control Room collaborative work with similar, like-minded utilities. This includes collaborative work with other local distribution companies to realize synergies and cost efficiencies for projects such as the expansion of control room operations. In 2021, Essex Powerlines indicated that its Control Room was not yet operating at 24 hours/day.

In reference 2, Essex Powerlines states,

> *"EPLC was not able to achieve desired results with the third-party and had to reassess the value of continuing to invest without achieving expected outcomes."*

OEB staff notes the increased costs associated with Essex Powerlines decision to discontinue the original third-party control room work and evaluate other options.

Question(s):

a) Is the Essex Powerlines Control Room currently operating 24 hours/day?
b) What specific collaborative work has been achieved with other utilities and their control rooms, and what is planned for over the forecast period?
c) How has this work affected historical and forecast control room operating and maintenance (O&M) cost?
d) Please explain what desired results Essex Powerlines was unable to achieve with the third-party as stated in reference 2.
e) Please explain what other options were evaluated and how Essex Powerlines determined that partnering with Welland Hydro was the most cost-effective option as stated in reference 2.

EPLC's Response:

a) The EPLC/Welland shared control room is in operation during the normal daily hours between Monday and Friday; but is available and supported 24 hours/day through on-call as needed.

b) EPLC is gaining knowledge and understanding of how these control rooms started out, issues they came up against, and to hear any learnings through the control room development process. Over the forecasted period, EPLC will continue to visit other control rooms to expand their knowledge with the goal of a fully functional 24-hour Control Room. The specific collaboration that has resulted in the current control room is work with Welland Hydro wherein EPLC has contributed expertise in engineering analysis and a real-time digital model of the distribution system, while Welland has complementary expertise in SCADA implementation and operation. Synergies are achieved through these complementary skills sets, and integration of software systems that support Control Room Operations.

c) This work caused historical control room costs to fluctuate over the 2018-2022 period. The forecasted control room costs are slightly higher due to realized enhancements from the original plan.

d) EPLC was unable to achieve a functioning control room with the third party.

e) EPLC investigated creating and staffing their own control room, working with other LDCs in their region that had an existing control room, and also investigated other LDCs that used similar tools (SmartMAP) and had a like-minded interest. Welland Hydro uses SmartMAP and had a functioning SCADA system. Welland Hydro was willing to provide basic SCADA access and commissioning knowledge for EPLC's smart devices. In addition, Welland Hydro agreed with furthering the development of SmartMAP to integrate with SCADA and partner on the shared Control Room concept.

2-Staff-10

**5.2.1 Distribution System Plan Overview Ref 1:
Distribution System Plan pages 2, 14**

Preamble:

In reference 1, Essex Powerlines states that it will continue to drive costs down with the implementation of modern management techniques and other process improvements

Question(s):

a) What specific costs have been driven down over the historical 2018 – 2023 period through the use of modern management techniques and other process improvements?

b) What specific costs are expected to be driven down over the forecast period through the use of modern management techniques and other process improvements?

EPLC's Response:

a) Using various software, EPLC's goal is to reduce costs by gaining efficiencies. During the 2018 – 2023 historical period, much effort was put into developing work processes within the Metering Department to allow for a digital transition. EPLC expects that moving from paperwork packages toward digital work packages will reduce sources of error and ultimately improve efficiency. Specific cost reductions would be qualitative rather than quantitative as EPLC is at the beginning of this digital transition.

b) For the forecast period, EPLC will continue to evolve the digitization of all work processes to include Engineering and the Operations field team. Through the digitalization process, EPLC expects to reduce process waste and yield efficiency improvements in workflow from design to execution.

2-Staff-11

5.2.1.2 Capital Investment Highlights

Ref 1: Distribution System Plan pages 10, 76, 78-80
Ref 2: Essex Powerlines_Chapter2Appendices_COS_20240517

Question(s):

a) DSP Tables 5.2-1, 5.4-1, 5.4-3, 5.4-4, and 5.4-5 O&M figures for 2018, 2019 and 2020 differ from App. 2-AB table for 2018, 2019 and 2020 O&M. Please reconcile and update evidence as necessary.

EPLC's Response:

a) DSP Tables 5.2-1, 5.4-1, 5.4-3, 5.4-4, and 5.4-5 O&M figures from 2018, 2019 and 2020 have been updated and now agree to Appendix 2-AB table for 2018, 2019, and 2020. The updated charts are included below:

Table 2-1: Resubmitted Table 5.2-1 in Exhibit 2

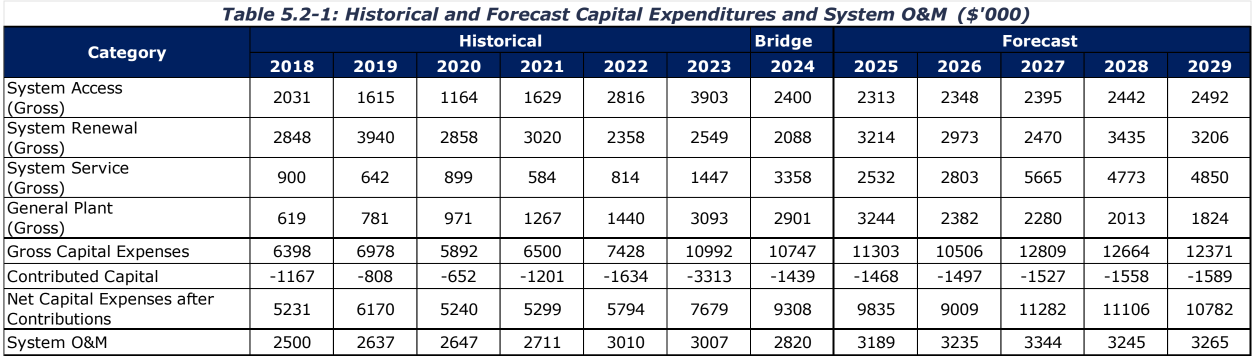


Table 5.2-1: Historical and Forecast Capital Expenditures and System O&M ($'000)

Category	**Historical**						**Bridge**	**Forecast**				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
System Access (Gross)	2031	1615	1164	1629	2816	3903	2400	2313	2348	2395	2442	2492
System Renewal (Gross)	2848	3940	2858	3020	2358	2549	2088	3214	2973	2470	3435	3206
System Service (Gross)	900	642	899	584	814	1447	3358	2532	2803	5665	4773	4850
General Plant (Gross)	619	781	971	1267	1440	3093	2901	3244	2382	2280	2013	1824
Gross Capital Expenses	6398	6978	5892	6500	7428	10992	10747	11303	10506	12809	12664	12371
Contributed Capital	-1167	-808	-652	-1201	-1634	-3313	-1439	-1468	-1497	-1527	-1558	-1589
Net Capital Expenses after Contributions	5231	6170	5240	5299	5794	7679	9308	9835	9009	11282	11106	10782
System O&M	2500	2637	2647	2711	3010	3007	2820	3189	3235	3344	3245	3265

Table 2-2: Resubmitted Table 5.4-1 in Exhibit 2

Table 5.4-1: Historical Capital Expenditures and System O&M

Category	2018			2019			2020			2021			2022			2023		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.
	$ ‘000		%	$ ‘000		%	$ ‘000		%	$ '000		%	$ ‘000		%	$ ‘000		%
System Access																		
Gross Capital Spend	1746	2031	16%	1781	1615	-9%	1816	1164	-36%	1836	1629	-11%	1835	2816	53%	2170	3903	80%
Capital Contributions	-1225	-1167	-5%	-1225	-808	-34%	-1225	-652	-47%	-1225	-1201	-2%	-1225	-1634	33%	-860	-3313	285%
Net Capital Expenditures	521	864	66%	556	807	45%	592	512	-13%	611	428	-30%	610	1182	94%	1309	590	-55%
System Renewal																		
Gross Capital Spend	2693	2848	6%	1362	3940	189%	2304	2858	24%	2196	3020	38%	2375	2358	-1%	2593	2549	-2%
Capital Contributions	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%
Net Capital Expenditures	2693	2848	6%	1362	3940	189%	2304	2858	24%	2196	3020	38%	2375	2358	-1%	2593	2549	-2%
System Service																		
Gross Capital Spend	707	900	27%	2186	642	-71%	1126	899	-20%	1342	584	-56%	1144	814	-29%	1622	1447	-11%
Capital Contributions	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%
Net Capital Expenditures	707	900	27%	2186	642	-71%	1126	899	-20%	1342	584	-56%	1144	814	-29%	1622	1447	-11%
General Plant																		
Gross Capital Spend	1037	619	-40%	856	781	-9%	976	971	-1%	968	1267	31%	968	1440	49%	2278	3093	36%
Capital Contributions	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%
Net Capital Expenditures	1037	619	-40%	856	781	-9%	976	971	-1%	968	1267	31%	968	1440	49%	2278	3093	36%
Total Expenditure, Gross	**6183**	**6398**	**3%**	**6185**	**6978**	**13%**	**6222**	**5892**	**-5%**	**6341**	**6500**	**3%**	**6322**	**7428**	**17%**	**8663**	**10992**	**27%**
Total Capital Contribution	**-1225**	**-1167**	**-5%**	**-1225**	**-808**	**-34%**	**-1225**	**-652**	**-47%**	**-1225**	**-1201**	**-2%**	**-1225**	**-1634**	**33%**	**-860**	**-3313**	**285%**
Total Expenditure, Net	**4958**	**5231**	**6%**	**4960**	**6170**	**24%**	**4997**	**5240**	**5%**	**5117**	**5299**	**4%**	**5097**	**5794**	**14%**	**7802**	**7679**	**-2%**
System O&M	3067	2500	-18.5%	3116	2637	-15%	3162	2647	-16%	3048	2711	-11%	3109	3010	-3%	2598	3007	16%

Table 2-3: Resubmitted Table 5.4-3 in Exhibit 2

Table 5.4-3: 2018 Variance Explanations - 2018 Planned Versus Actuals

Category	2018				Justification
	Plan.	Act.	Var.	Var.	
	$ `000			%	
System Access, Gross	$1,746	$2,031	$285	16%	The increase in system access expenditures in 2018 was due to unanticipated customer growth. EPLC had planned for 150 new connections, however the actual number of new connections required was 386.
System Renewal, Gross	$2,693	$2,848	$155	6%	Contractor costs that were being used for executing EPLC projects were higher than anticipated.
System Service, Gross	$707	$900	$193	27%	There were unanticipated distribution costs at Leamington TS. This was due to Hydro One building a new TS at Leamington, and then allocating capital contributions that each impacted party needed to pay.
General Plant, Gross	$1,037	$619	-$418	-40%	EPLC deferred the rehabilitation of a parking lot and a vehicle purchase. Additionally, EPLC's locate costs were lower than anticipated.
Total Expenditure, Gross	$6,183	$6,398	$215	3%	N/A
Capital Contributions	-$1,225	-$1,167	$58	-5%	N/A
Total Expenditure, Net	$4,958	$5,231	$273	6%	N/A
System O&M	$3,067	$2,500	-$567	-18.5%	EPLC did not launch their control room, which would have cost approximately $120,000. Additionally, a contractor was unable to complete all planned Vegetation Management and deferred their Vegetation Management program.

Table 2-4: Resubmitted Table 5.4-4 in Exhibit 2

Table 5.4-4: Variance Explanations -2019 Planned Versus Actuals

Category	2019				Justification
	Plan.	Act.	Var.	Var.	
	$ `000			%	
System Access, Gross	$1,781	$1,615	-$166	-9%	EPLC did not reach their planned spending allocation for System Access projects due to delays in some planned developments and the deferral of planned municipal projects.
System Renewal, Gross	$1,362	$3,940	$2,578	189%	EPLC faced higher than average unit costs for pole replacements and a higher volume of replacements required; there were 111 replacements planned and 139 were completed. Additionally, underground replacements had higher than average unit costs. Some deferred amounts originally allocated to System Service expenditures were moved to System Renewal, which is another contributor to the discrepancy between planned and actual expenditures in both the System Renewal and System Service categories.
System Service, Gross	$2,186	$642	-$1,544	-71%	A new feeder project at Malden was deferred as HONI provided access to an underloaded feeder instead. A planned asset purchase from HONI was deferred, as HONI did not sell the assets that EPLC planned to acquire
General Plant, Gross	$856	$781	-$75	-9%	Variance does not meet materiality threshold.
Total Expenditure, Gross	$6,185	$6,978	$793	13%	See comments above
Capital Contributions	-$1,225	-$808	$417	-34%	See comments above
Total Expenditure, Net	$4,960	$6,170	$1,210	24%	See comments above
System O&M	$3,116	$2,637	$479	-15%	EPLC saw an improvement in their SAIDI and SAIFI, therefore lowered maintenance, and operating costs. Additionally, some noncritical inspections activities were deferred

Table 2-5: Resubmitted Table 5.4-5 in Exhibit 2

Table 5.4-5: Variance Explanations -2020 Planned Versus Actuals

Category	2020				Justification
	Plan.	Act.	Var.	Var.	
	$ `000			%	
System Access, Gross	$1,816	$1,164	-$652	-36%	Various planned municipal requests were deferred. Additionally, the required new services and upgrades were below average due to the affects of Covid-19.
System Renewal, Gross	$2,304	$2,858	$554	24%	EPLC shifted deferred funds from System Access and System Service expenditure categories to increase System Renewal projects to address assets at risk of failure. Additionally, unit costs were higher than average.
System Service, Gross	$1,126	$899	-$227	-20%	EPLC did not reach the planned System Service expenditure allocation because HONI did not sell assets that EPLC had planned to purchase.
General Plant, Gross	$976	$971	-$5	-1%	Variance does not meet materiality threshold
Total Expenditure, Gross	$6,222	$5,892	-$330	-5%	See comments above
Capital Contributions	-$1,225	-$652	$573	-47%	See comments above
Total Expenditure, Net	$4,997	$5,240	$243	5%	See comments above
System O&M	$3,162	$2,647	$515	-16.3%	Non-critical inspections activities were deferred due to the COVID-19 pandemic.

2-Staff-12

5.2.4 Performance Measurement for Continuous Improvement
Ref 1: Distribution System Plan pages 23-37

Preamble:

Essex Powerlines has provided historical performance information for the 2018 – 2022 period. 2023 SAIDI and SAIFI numbers are considerably higher than targets and recent historical performance.

Question(s):

a) Please provide 2023 performance information for all tables and charts in DSP section 5.2.4 Performance Measurement for Continuous Improvement that are not included in Appendix 2-G.
b) Please explain the cause of 2023 SAIDI and SAIFI performance higher than target.
c) Please provide 2018 – 2023 SAIDI and SAIFI performance for each of the four non-contiguous regions in the Essex Powerlines service area.

EPLC's Response:

a) 2023 performance information for all tables and charts in DSP section 5.2.4 is shown below:

Table 2-6: Resubmitted Table 5.2-6 and Table 5.2-7 in Exhibit 2

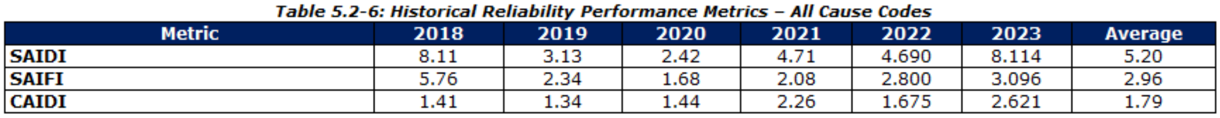


Table 5.2-6: Historical Reliability Performance Metrics – All Cause Codes

Metric	2018	2019	2020	2021	2022	2023	Average
SAIDI	8.11	3.13	2.42	4.71	4.690	8.114	5.20
SAIFI	5.76	2.34	1.68	2.08	2.800	3.096	2.96
CAIDI	1.41	1.34	1.44	2.26	1.675	2.621	1.79

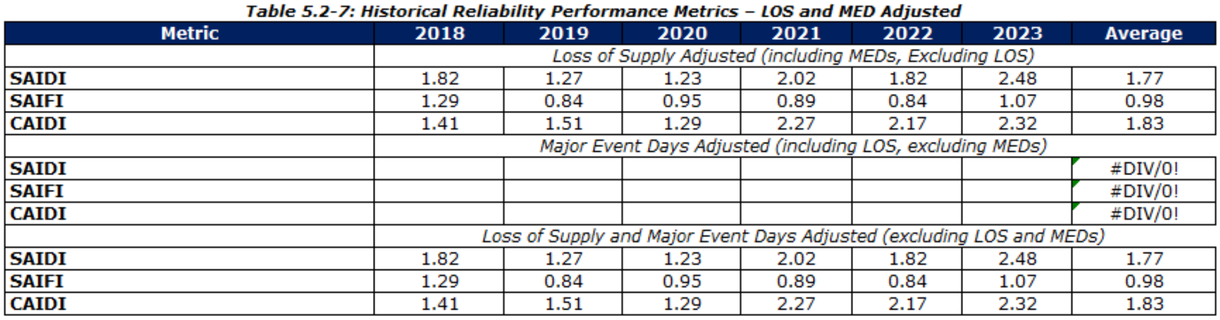


Table 5.2-7: Historical Reliability Performance Metrics – LOS and MED Adjusted

Metric	2018	2019	2020	2021	2022	2023	Average
	Loss of Supply Adjusted (including MEDs, Excluding LOS)						
SAIDI	1.82	1.27	1.23	2.02	1.82	2.48	1.77
SAIFI	1.29	0.84	0.95	0.89	0.84	1.07	0.98
CAIDI	1.41	1.51	1.29	2.27	2.17	2.32	1.83
	Major Event Days Adjusted (including LOS, excluding MEDs)						
SAIDI							#DIV/0!
SAIFI							#DIV/0!
CAIDI							#DIV/0!
	Loss of Supply and Major Event Days Adjusted (excluding LOS and MEDs)						
SAIDI	1.82	1.27	1.23	2.02	1.82	2.48	1.77
SAIFI	1.29	0.84	0.95	0.89	0.84	1.07	0.98
CAIDI	1.41	1.51	1.29	2.27	2.17	2.32	1.83

Table 2-7: Resubmitted Table 5.2-8 in Exhibit 2

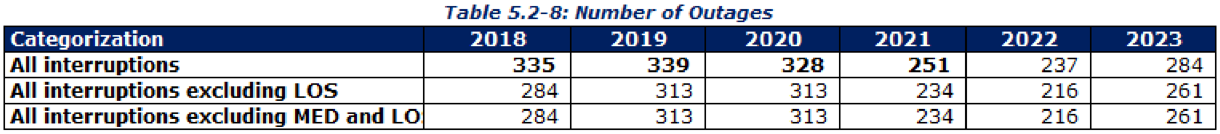


Table 5.2-8: Number of Outages

Categorization	2018	2019	2020	2021	2022	2023
All interruptions	**335**	**339**	**328**	**251**	237	284
All interruptions excluding LOS	284	313	313	234	216	261
All interruptions excluding MED and LO	284	313	313	234	216	261

Table 2-8: Resubmitted Table 5.2-9 in Exhibit 2

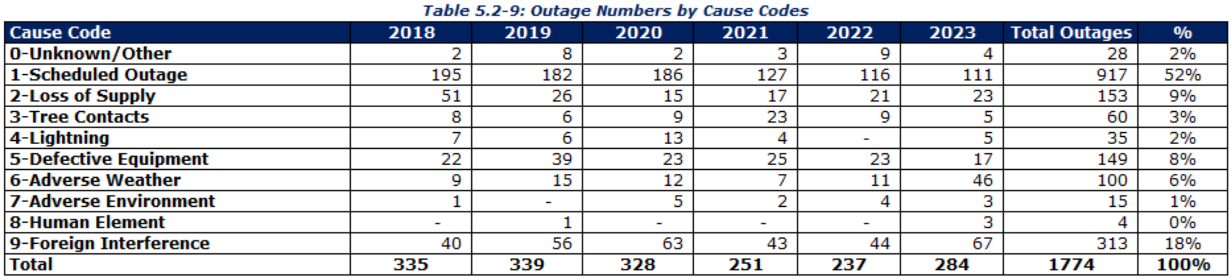


Table 5.2-9: Outage Numbers by Cause Codes

Cause Code	2018	2019	2020	2021	2022	2023	Total Outages	%
0-Unknown/Other	2	8	2	3	9	4	28	2%
1-Scheduled Outage	195	182	186	127	116	111	917	52%
2-Loss of Supply	51	26	15	17	21	23	153	9%
3-Tree Contacts	8	6	9	23	9	5	60	3%
4-Lightning	7	6	13	4	-	5	35	2%
5-Defective Equipment	22	39	23	25	23	17	149	8%
6-Adverse Weather	9	15	12	7	11	46	100	6%
7-Adverse Environment	1	-	5	2	4	3	15	1%
8-Human Element	-	1	-	-	-	3	4	0%
9-Foreign Interference	40	56	63	43	44	67	313	18%
Total	**335**	**339**	**328**	**251**	**237**	**284**	**1774**	**100%**

Table 2-9: Resubmitted Table 5.2-10 in Exhibit 2

Table 5.2-10: Customers Interrupted Numbers by Cause Codes - Excluding MEDs

Cause Code	2018	2019	2020	2021	2022	2023	Total CI	%
0-Unknown/Other	163	219	38	157	2,813	82	3,472	1%
1-Scheduled Outage	14,976	5,651	10,091	7862	3,356	5,256	47,192	9%
2-Loss of Supply	134,448	45,323	22,200	36691	61,201	63,697	363,560	67%
3-Tree Contacts	4,085	272	1,813	2502	653	3,016	12,341	2%
4-Lightning	831	352	4,782	313	-	503	6,781	1%
5-Defective Equipment	1,627	11,179	5,427	4044	5,334	5,925	33,536	6%
6-Adverse Weather	8,972	4,715	978	4617	5,854	11,504	36,640	7%
7-Adverse Environment	41	-	106	2263	3,060	66	5,536	1%
8-Human Element	-	11	-	-	-	782	793	0%
9-Foreign Interference	8,082	3,190	6,030	5933	5,226	6,310	34,771	6%
Total	**173,225**	**70,912**	**51,465**	**64382**	**87,497**	**97,141**	**544,622**	**100%**

Table 2-10: Resubmitted Table 5.2-11 in Exhibit 2

Table 5.2-11: Customer Hours Interrupted Numbers by Cause Codes - Excluding MEDs

Cause Code	2018	2019	2020	2021	2022	2023	Total CHI	%
0-Unknown/Other	274	635	96	429	4,302	199	5,935	1%
1-Scheduled Outage	12,644	9,065	8,468	10927	5,883	10,587	57,574	6%
2-Loss of Supply	188,983	56,318	36,689	83375	89,677	176,780	631,822	66%
3-Tree Contacts	4,657	1,547	3,126	7162	821	3,624	20,938	2%
4-Lightning	2,708	1,428	5,389	2584	-	1,742	13,851	1%
5-Defective Equipment	4,719	13,588	5,573	8309	13,267	5,360	50,814	5%
6-Adverse Weather	25,027	5,071	2,875	19231	24,039	49,599	125,842	13%
7-Adverse Environment	113	-	72	1667	721	76	2,649	0%
8-Human Element	-	20	-	-	-	619	639	0%
9-Foreign Interference	4,571	7,221	12,052	12110	7,769	5,908	49,630	5%
Total	**243,697**	**94,893**	**74,339**	**145793**	**146,480**	**254,493**	**959,694**	**100%**

Figure 5.2-5:

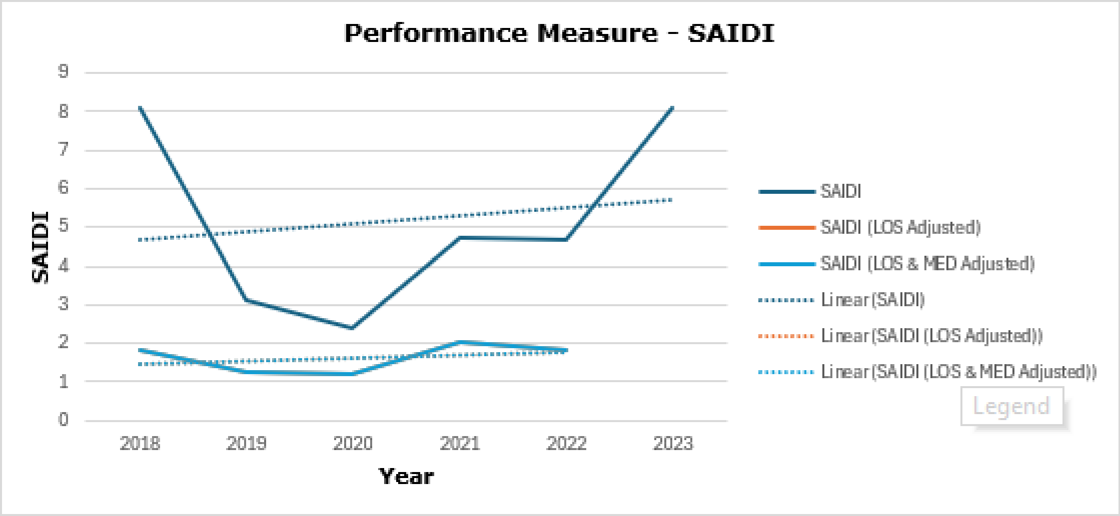


Figure 5.2-6:

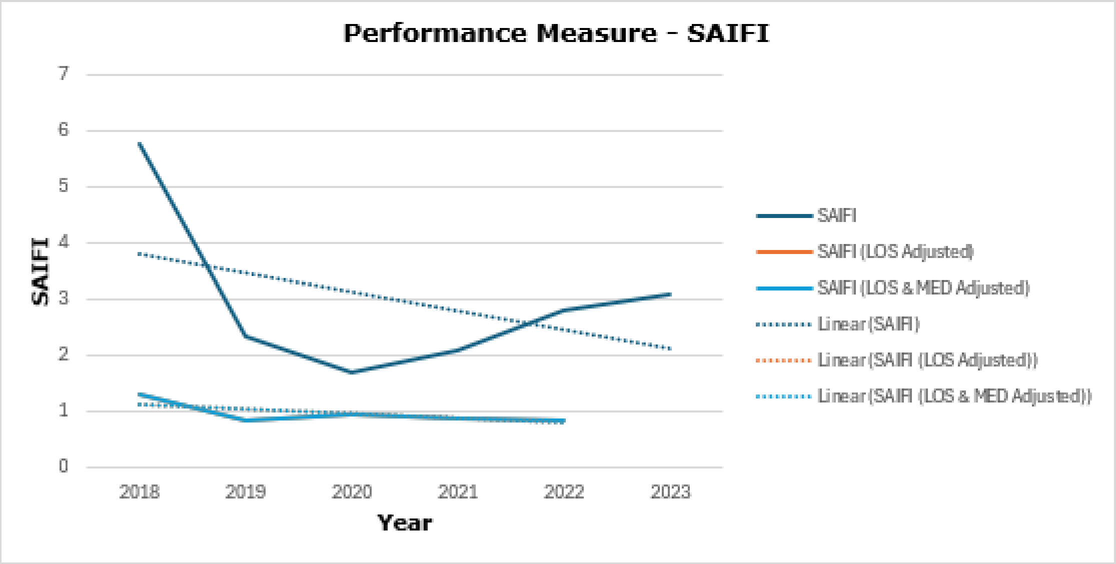


Figure 5.2-7:

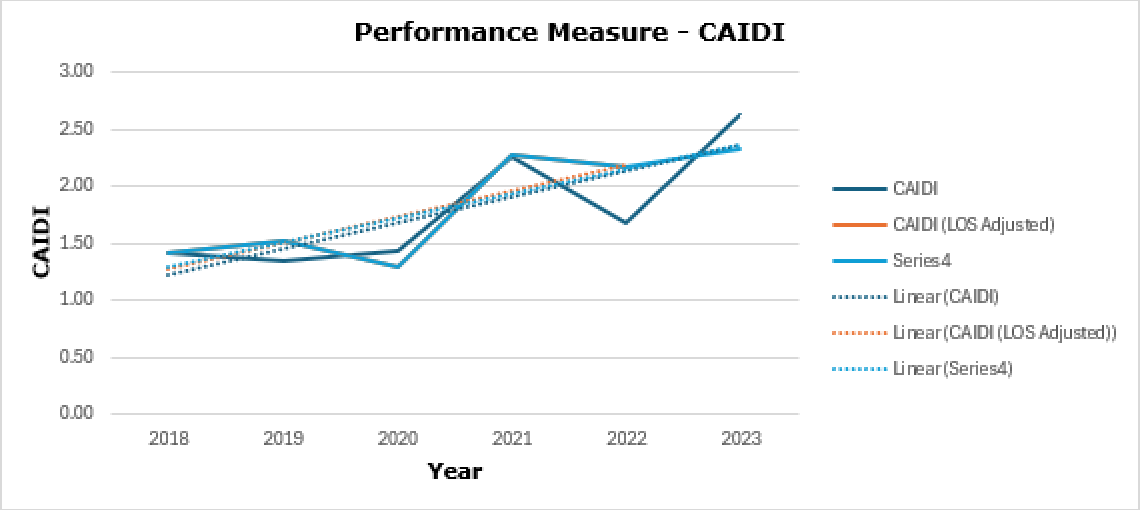


Figure 5.2-8:

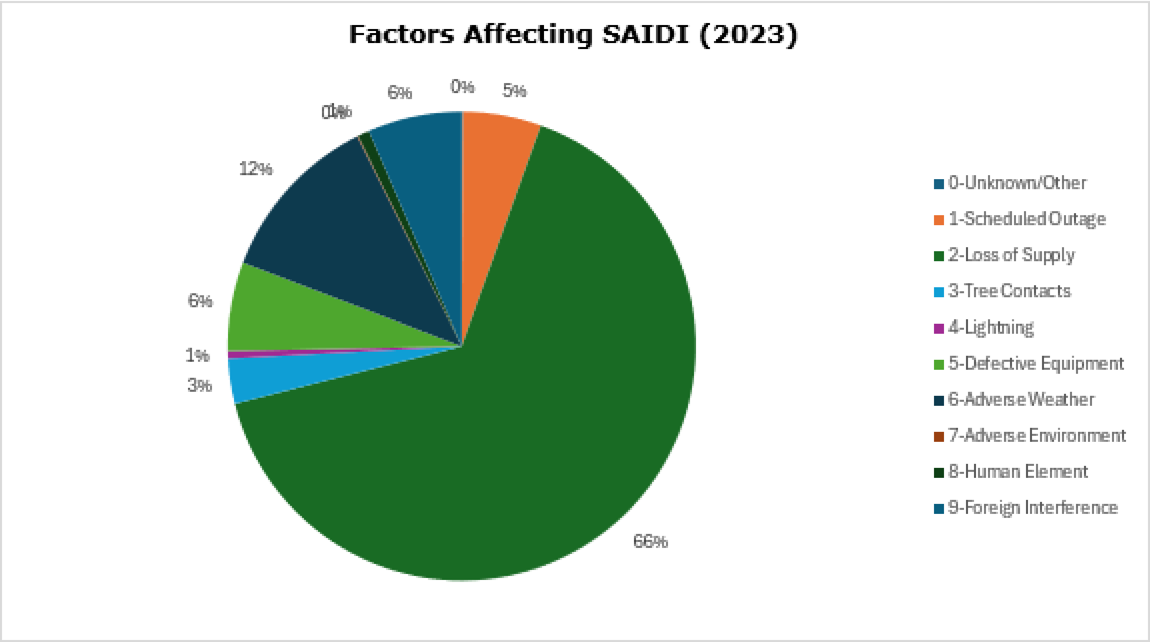


Figure 5.2-9:

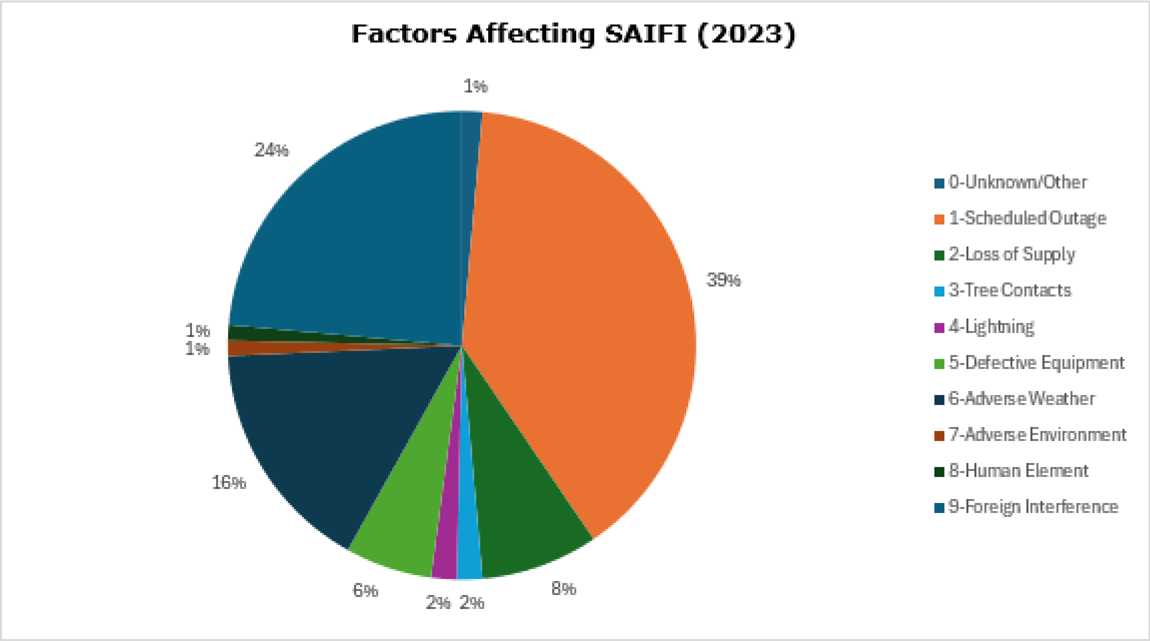


Figure 5.2-10:

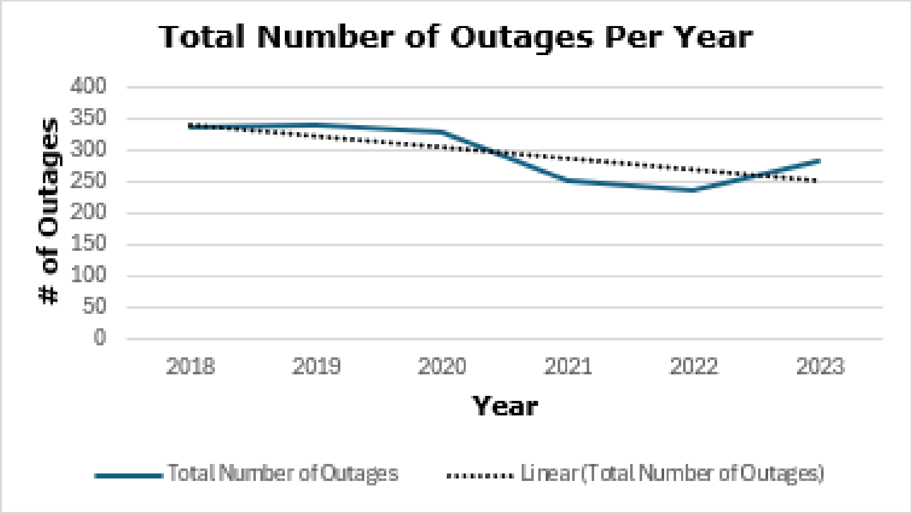


Figure 5.2-11:

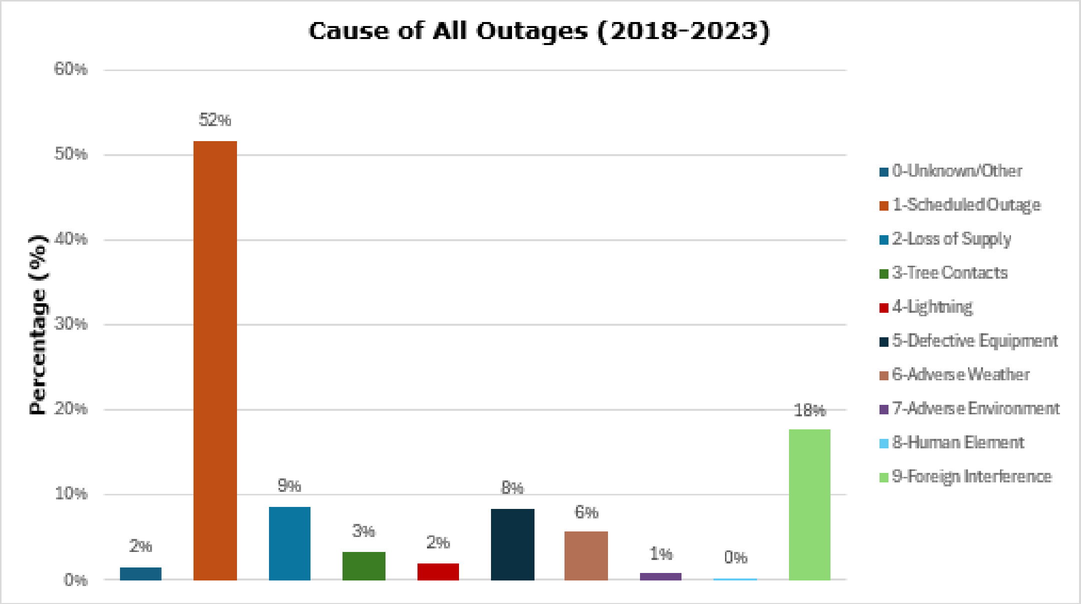


Figure 5.2-12:

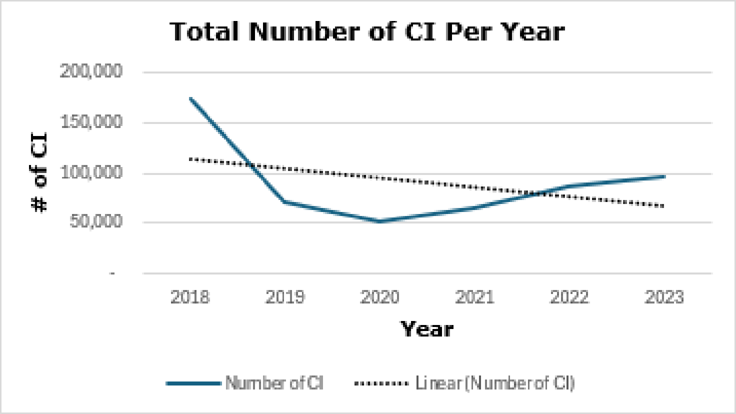
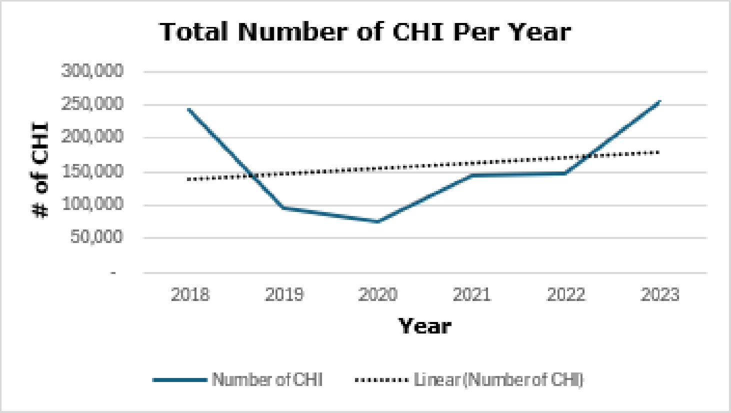


Figure 5.2-13:



b) 2023 SAIDI and SAIFI performance was significantly impacted by multiple weather events in the region. First, EPLC experienced an ice storm on February 23rd that impacted the entire region. This storm caused significant damage to some of EPLC's assets, as well as EPLC's joint-use partner's assets. Secondly, there were heavy rain and strong wind events on July 2nd, July 20th, and July 26/27th that caused multiple outages in the region affecting all of EPLC's serviced communities. These weather events combined with higher than usual wildlife contacts in July through September, contributed to an increase in EPLC's SAIDI and SAIFI indices.

c) SAIDI and SAIFI data is calculated based on the totality of EPLC's service area and not by specific community. EPLC does not maintain the customer outage count data for each serviced community separately.

2-Staff-13

5.2.4 Performance Measurement for Continuous Improvement
Ref 1: Distribution System Plan page 37

Preamble:

Essex Powerlines states that Asset performance is measured by the annual number of cable failures and annual number of switchgear failures.

Question(s):

a) Please provide these figures for the 2018 – 2023 historical period.

EPLC's Response:

a) The annual number of cable and switchgear failures for the 2018-2023 historical period is shown in the below table:

Table 2-11: Annual Number of Cable and Switchgear Failures

	Year					
	2018	2019	2020	2021	2022	2023
Primary Cable Fail	2	1	3	4	2	1
Switchgear Fail	0	3	0	0	2	0

2-Staff-14

5.3 Asset Management Process
Ref 1: Distribution System Plan page 39

Preamble:

Essex Powerlines has identified seven business objectives for prioritizing investments. The seven business objectives have been assigned relative weights for the purpose of prioritizing investments.

Question(s):

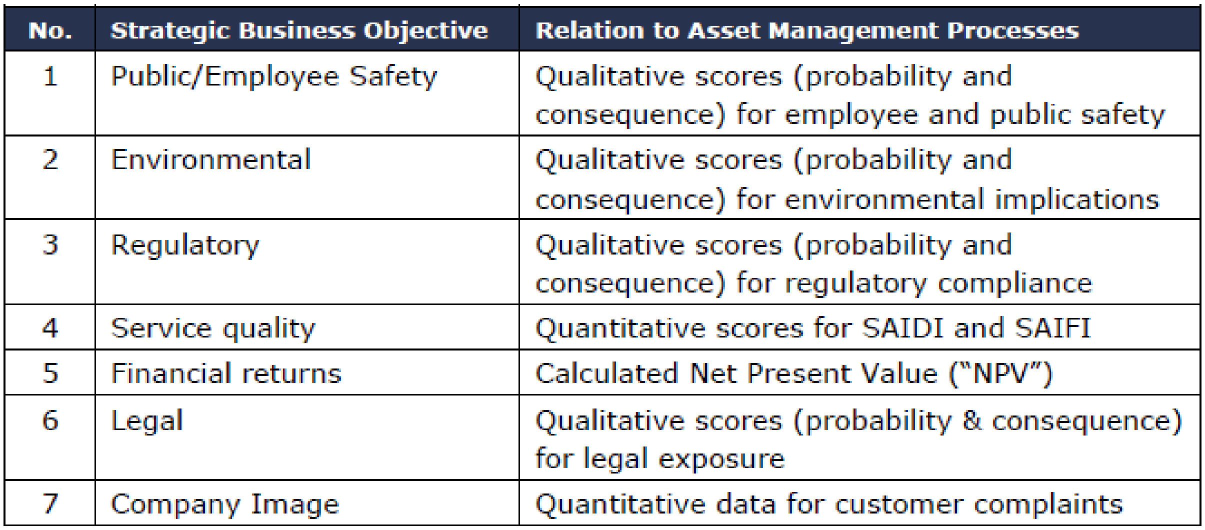
a) Please indicate how the weights were calculated and assigned by Essex Powerlines.

EPLC's Response:

a) Each strategic business objective is described by subsequent performance attributes that describe a project's contribution towards these objectives. EPLC determined the following business performance attributes to assess benefits and risks for each project as defined in Table 5.3-1 (below)

Table 2-12: Strategic Business Objective Weightings

Table 5.3-1: EPLC's Asset Management Objectives and Related Corporate Goals



No.	Strategic Business Objective	Relation to Asset Management Processes
1	Public/Employee Safety	Qualitative scores (probability and consequence) for employee and public safety
2	Environmental	Qualitative scores (probability and consequence) for environmental implications
3	Regulatory	Qualitative scores (probability and consequence) for regulatory compliance
4	Service quality	Quantitative scores for SAIDI and SAIFI
5	Financial returns	Calculated Net Present Value ("NPV")
6	Legal	Qualitative scores (probability & consequence) for legal exposure
7	Company Image	Quantitative data for customer complaints

These weights were assessed through the utilization of a risk-based approach as described in EPLC's Distribution System Plan Section 5.3.3. EPLC sets its numerical weights for the seven asset management objectives based on the above and in conjunction with best utility practice and are subject to annual review. These relative weights are listed as follows:

i. Financial Returns – 11%
ii. Service Quality – 13%
iii. Safety – 25%
iv. Environmental – 19%
v. Regulatory – 18%
vi. Legal – 8%
vii. Company Image – 6%

2-Staff-15

5.3 Asset Management Process
Ref 1: Distribution System Plan page 39

Preamble:

In reference 1, Essex Powerlines states that starting in 2019, its SmartMAP tool is capable of detecting the presence of EV's by identifying the charge characteristics associated with an individual residential meter.

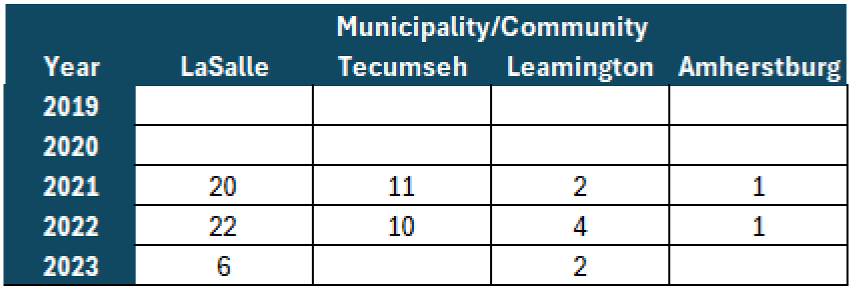
Question(s):

a) Please provide the 2019 – 2023 number of EVs detected by the SmartMAP tool in each of the four non-contiguous regions in the Essex Powerlines service area.

EPLC's Response:

a) The development of the detection algorithm began in 2019 and transitioned through various iterations into an actual working model in 2021. The detection algorithm identifies charge characteristics associated with an individual residential meter. The 2019 – 2023 number of EV's detected by the SmartMAP tool is shown in the table below:

Table 2-13: EV Detection Numbers



	Municipality/Community			
Year	LaSalle	Tecumseh	Leamington	Amherstburg
2019				
2020				
2021	20	11	2	1
2022	22	10	4	1
2023	6		2	

2-Staff-16

5.3.2 Overview of Assets Managed
Ref 1: Distribution System Plan page 47-48

Question(s):

a) Please update DSP Tables 5.3-2, 5.3-3, 5.3-4 with 2023 data.

EPLC's Response:

a) The tables have been updated and are shown below:

Table 2-14: Changing Trends in Customer Base

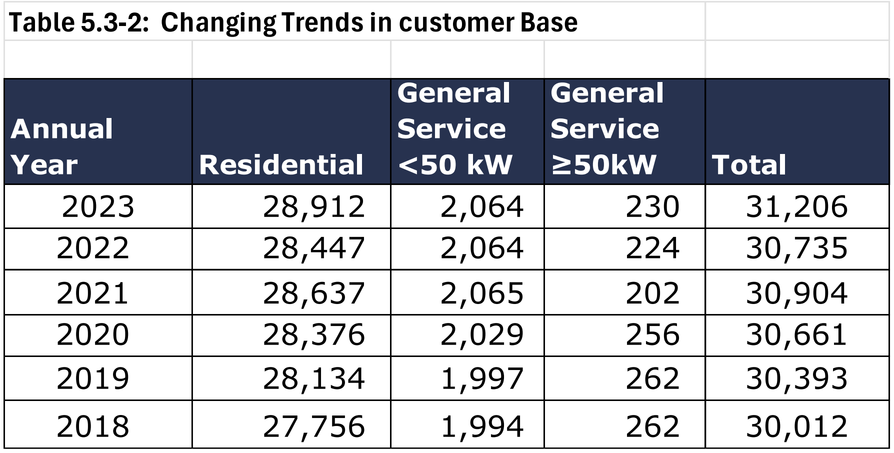


Table 5.3-2: Changing Trends in customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2023	28,912	2,064	230	31,206
2022	28,447	2,064	224	30,735
2021	28,637	2,065	202	30,904
2020	28,376	2,029	256	30,661
2019	28,134	1,997	262	30,393
2018	27,756	1,994	262	30,012

Table 2-15: Peak System Demand Statistics

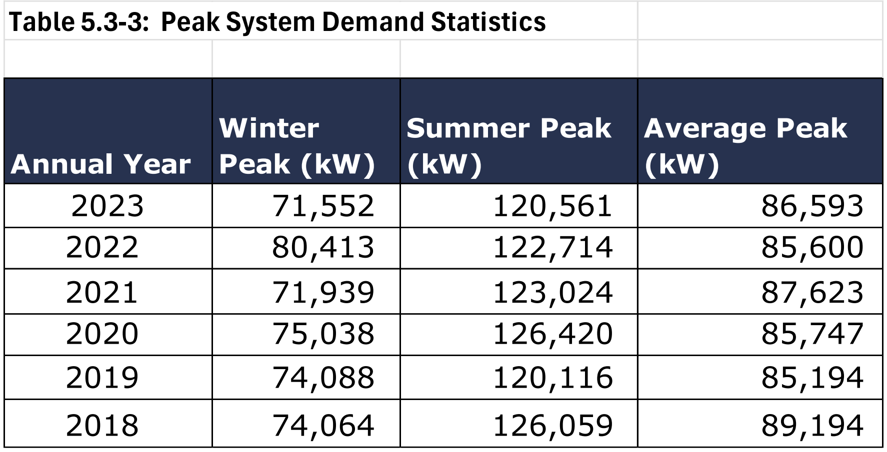


Table 5.3-3: Peak System Demand Statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2023	71,552	120,561	86,593
2022	80,413	122,714	85,600
2021	71,939	123,024	87,623
2020	75,038	126,420	85,747
2019	74,088	120,116	85,194
2018	74,064	126,059	89,194

Table 2-16: Efficiency of kWh Purchased by EPLC

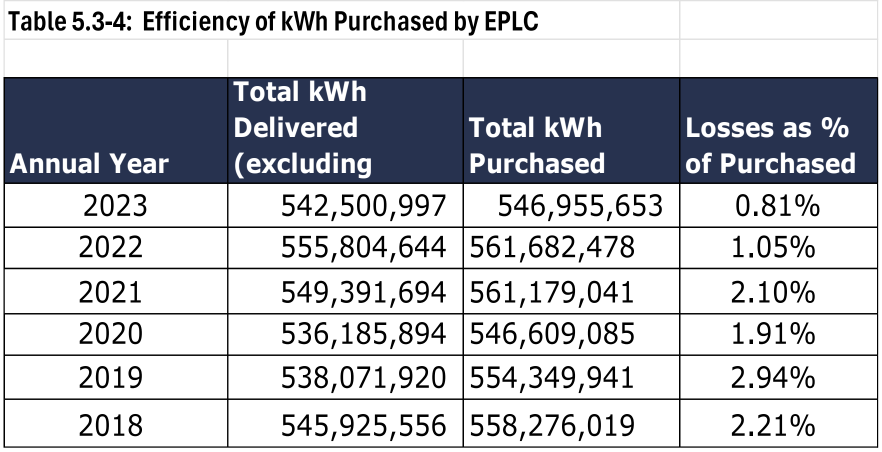


Table 5.3-4: Efficiency of kWh Purchased by EPLC

Annual Year	Total kWh Delivered (excluding	Total kWh Purchased	Losses as % of Purchased
2023	542,500,997	546,955,653	0.81%
2022	555,804,644	561,682,478	1.05%
2021	549,391,694	561,179,041	2.10%
2020	536,185,894	546,609,085	1.91%
2019	538,071,920	554,349,941	2.94%
2018	545,925,556	558,276,019	2.21%

2-Staff-17

5.3.2 Overview of Assets Managed
Ref 1: Distribution System Plan page 53

Preamble:

Essex Powerlines states that between 2024 and 2025, Essex Powerlines expects to add 18MW of night load and about 3 to 4 MW of baseload due to increased production of greenhouses and manufacturing within the Leamington and Amherstburg service areas.

Question(s):

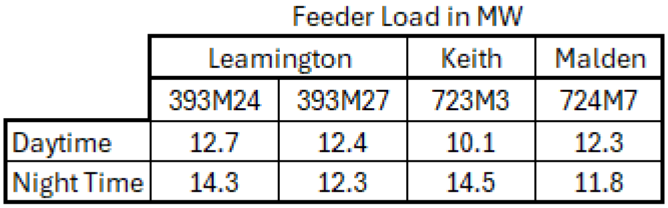
a) Have these figures been incorporated into Essex Powerlines' load forecasts for consumption and demand provided in Exhibit 3?
b) What is the projected day/night demand on the existing distribution feeders that supply these areas?

EPLC's Response:

a) Yes, these figures of approximately 18 MW of night load and approximately 3 to 4 MW of baseload have been incorporated into Essex Powerlines' load forecasts for consumption and demand provided in Exhibit 3.

b) It is important to note that the added lighting load is relative to only the October to April time frames. To accommodate this demand, some reconfiguration of EPLC internal network, as well as access to an additional feeder, is required. The projected day/night demand on these existing distribution feeders for the October to April timeframe with the reconfiguration is shown in the below table:

Table 2-17: Feeder Load in MW



Feeder Load in MW

	Leamington		Keith	Malden
	393M24	393M27	723M3	724M7
Daytime	12.7	12.4	10.1	12.3
Night Time	14.3	12.3	14.5	11.8

2-Staff-18

Asset Condition Assessment
Ref 1: Distribution System Plan page 54-57
Ref 2: Appendix B: 2023 Asset Condition Assessment (ACA) Report

Preamble:

The October 2023 Asset Condition Assessment Report by BBA provided a number of recommendations for data improvement to aid in assessing the health index of assets.

Question(s):

a) For the recommendations provided, please advise of Essex Powerlines' acceptance or rejection of the individual recommendations and the time frame in which Essex Powerlines would institute the recommended practices.

EPLC's Response:

a) EPLC has noted the recommendations in the ACA and largely accepts them. BBA recommends collecting additional and missing data related to assets to improve accuracy and add incremental value. EPLC has begun implementing these changes. Specifically, EPLC has added fields within the GIS mapping system to track additional information; added additional inspection requirements for transformers; and added requirements to the assessment process, such as collecting pictures of the oil level and temperature gauge. These practices will give EPLC additional information to assist in asset replacement decisions.

2-Staff-19

Table 5.4-4: Variance Explanations - 2019 Planned Versus Actuals
Ref 1: Distribution System Plan page 79

Preamble:

Table 5.4-4 O&M Variance explanation states that Essex Powerlines saw an improvement in their SAIDI and SAIFI, therefore lowered maintenance, and operating costs.

Question(s):

a) Please elaborate on the nature of lowered maintenance and operating costs (i.e., reduction in overtime costs, etc.?).

EPLC's Response:

a) Lowered maintenance and operating costs are due in part to the improvement in SAIDI and SAIFI which reduced the amount of overtime and after-hours call outs. These savings were realized from the replacement of manual load-break switches with smart switches and the addition of visual indicating, fault detecting line monitors. Additionally, EPLC deferred the inspection of load break switches and PMH switching cubicles as these were low risk and planned for replacement.

2-Staff-20

System O&M Costs
Ref 1: Distribution System Plan page 102

Preamble:

Average 2018-2023 O&M was $2.5M. 2024 O&M costs are estimated to be $2.8M. This represents a 13% increase in cost. 2025 O&M costs are forecast to be $3.2M. This represents a 13% increase in costs over 2024 O&M and a 28% increase in costs over 2018 – 2023 historical average.

Question(s):

a) Please explain the increase in 2025 O&M costs over 2013-2018 historical average and 2024 projected O&M.

EPLC's Response:

a) EPLC is anticipating a resurgence of developments through 2024 and 2025 to exceed the historical average. This and the historical growth will and has caused EPLC's asset pool to significantly increase.

This increase in assets will have an upward pressure on system O&M due to increased inspections and maintenance. EPLC, like many other utilities, has experienced a significant increase in material and contractor costs. In addition, there is an industry-wide shortage of skilled labour, and technological advancements are demanding new skills from trades and technical staff. As a result, EPLC has engaged in workforce planning to ensure required skills and talent are available to maintain and grow its distribution system and meet the changing demands of its customers over the next five years and beyond. As part of this planning EPLC has added two additional Apprentice Line Maintainer positions to ensure that knowledge transfer of senior positions is secured.

2-Staff-21

Forecast System Access Expenditures
Ref 1: Distribution System Plan pages 82-86, 98-99
Ref 2: Distribution System Plan – Appendix A: Material Investment Narratives pages 35-49

Preamble:

Essex Powerlines has provided forecast System Access expenditures based on known investments and historical trends.

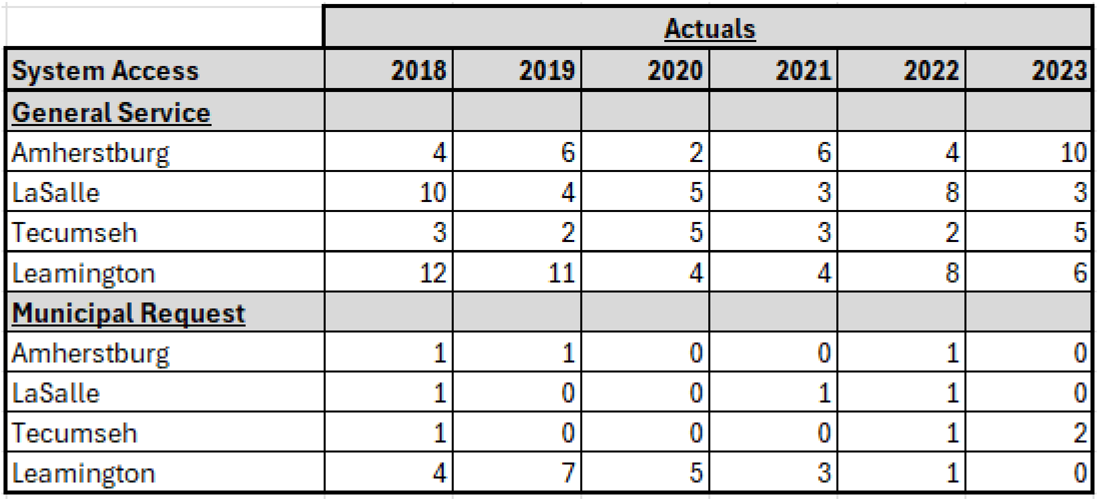
Question(s):

a) Please provide the number of general service projects completed in each of the four non-contiguous regions in the Essex Powerlines service area for each year of the 2018 – 2023 historical period.
b) Please provide the number of Municipal Request projects in each of the four non-contiguous regions in the Essex Powerlines service area for each year of the 2018 – 2023 historical period.
c) Please provide the number of Residential Connections for each year of the 2018 – 2023 historical period.
d) Please provide the number of Subdivision units for each year of the 2018 – 2023 historical period.

EPLC's Response:

Please find the results of a) & b) listed in the table below:

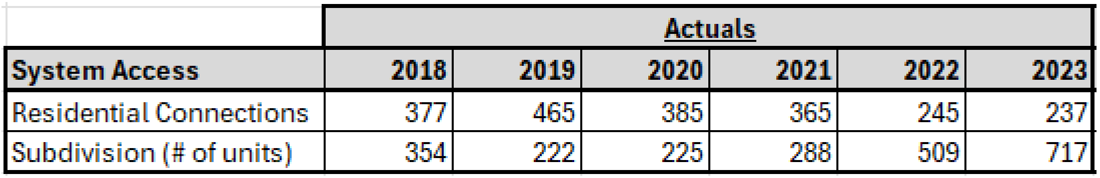
Table 2-18: General Service and Municipal Projects



	Actuals					
System Access	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
General Service						
Amherstburg	4	6	2	6	4	10
LaSalle	10	4	5	3	8	3
Tecumseh	3	2	5	3	2	5
Leamington	12	11	4	4	8	6
Municipal Request						
Amherstburg	1	1	0	0	1	0
LaSalle	1	0	0	1	1	0
Tecumseh	1	0	0	0	1	2
Leamington	4	7	5	3	1	0

Please find the results of c) & d) listed in the table below:

Table 2-19: Residential Connections and Subdivisions



	Actuals					
System Access	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Residential Connections	377	465	385	365	245	237
Subdivision (# of units)	354	222	225	288	509	717

2-Staff-22

Forecast System Renewal Expenditures
Ref 1: Distribution System Plan pages 86-88, 99-100
Ref 2: Distribution System Plan – Appendix A: Material Investment Narratives pages 50-

Preamble:

Essex Powerlines has provided forecast System Renewal expenditures based on needs identified from annual inspection data, the latest Asset Condition Assessment and customer servicing requirements. Essex Powerlines states that it plans to replace approximately an average of 60 poles a year as part of its 2025-2029 Pole Replacement program.

Question(s):

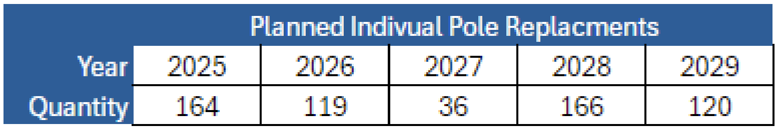
a) Does the TEC Clarice OH rebuild and the LEA Bowman OH rebuild remove all rear-lot infrastructure?
b) Pole replacement costs are not consistent over the 2025-2029 forecast period. Please provide the number of poles to be replaced in each of the 2025-2029 forecast years for the Pole Replacement program.

EPLC’s Response:

a) No, the TEC Clarice OH Rebuild includes only EPLC's primary circuit and transformer removal from the rear yard. The remaining infrastructure, poles, and secondary circuits will remain. The poles are not EPLC's assets and carry communications infrastructure. The LEA Bowman OH Rebuild will not remove any infrastructure. The open-wire secondary buss is planned to be upgraded to insulated triplex.

b) During the 2018-2023 historical period EPLC planned for an average of 60-80 individual poles to be replaced per year. Since 2021, the quantity of poles to be replaced is trending higher than historical numbers. These planned replacements are based on results of visual and drill testing during EPLC's preventative maintenance inspections. The quantity of poles inspected varies from year to year. This plan includes reactive replacements but does not include planned pole line rebuilds. If the reactive replacements are higher than anticipated, the quantity of planned poles for replacement may be reduced. The planned individual pole replacements for the 2025-2029 forecast period are shown in the table below:

Table 2-20: Planned Individual Pole Replacements



	Planned Indivual Pole Replacments				
Year	2025	2026	2027	2028	2029
Quantity	164	119	36	166	120

2-Staff-23

Forecast System Service Investments
Ref 1: Distribution System Plan pages 12, 68, 89, 92, 105, 109
Ref 2: Distribution System Plan – Appendix A: Material Investment Narratives pages 73-75

Preamble:

Essex Powerlines states that a new program is being put in place over the 2025 – 2029 forecast period for Network upgrades from 100A to 200A to facilitate the increase in EV chargers and other devices being installed at residential locations. Essex Powerlines references Ontario Energy Board (OEB) Bulletin issued on August 24, 2023, on Residential Customer Connections, Service Upgrades, and newly constructed homes as a driver for this program. Essex Powerlines is expecting to upgrade approximately 8 combined overhead and underground infrastructure per year from 100A to 200A over the forecast period. Essex Powerlines states that this investment is considered to be of low priority and is a proactive upgrade. The August 24, 2023 OEB Bulletin states that it is "…not intended to suggest distributors should proactively upgrade transformers across their service areas to accommodate a 200-amp service capacity for all residential customers."

Question(s):

a) What are the distribution system components affected by the 200A upgrade (i.e., distribution transformers, service conductors, other components)?

b) Has Essex Powerlines standardized on 200A infrastructure going forward for new residential customer connection requests?
c) As proactive infrastructure upgrades are not supported by the OEB August 24, 2023 bulletin, please provide the business case or cost benefit analysis Essex Powerlines used to support these expenditures.

EPLC's Response:

a) A single residential 200A service upgrade may only require the secondary service cable to be upgraded. When looking at multiple service upgrades on a single transformer, the components may include poles, transformers, conduit, underground and overhead service conductors, secondary buss network, as well as Engineering time to investigate and design the appropriate infrastructure upgrades while coordinating appropriate protection philosophy. It is unlikely that Primary conductors would require upsizing however, fusing and fuse holders would likely need to be replaced or upgraded accordingly.
b) Yes, EPLC has standardized its underground service conductors to accommodate a 200A service for new build single family or multi-plex (duplex, tri-plex, etc.) residential builds. This does not extend to Multi Unit Residential Buildings (MURBs).
c) EPLC notes that these infrastructure upgrades would be completed as needed and <u>not</u> proactively. EPLC wants to ensure that it is prepared for these infrastructure upgrades, due to electrification, when they are needed so that the existing investment programs are not negatively impacted. EPLC is following the guidance of prudent planning in preparation for the demands of its customer base.

2-Staff-24

Forecast System Service Investments
Ref 1: Distribution System Plan pages 12, 18, 34, 68, 79-80, 89, 92
Ref 2: Distribution System Plan – Appendix A: Material Investment Narratives pages 65-72

Preamble:

Essex Powerlines states that it has planned for asset purchases and asset transfers from HONI. This includes three feeder sections in Amherstburg and two feeder sections in Leamington. Planned asset purchases from HONI in 2019, 2020, 2021, 2022 and 2023 did not occur as HONI did not sell assets that Essex Powerlines desired to purchase.

Question(s):

a) As HONI has not sold assets to Essex Powerlines in the historical period, what assurances are there that HONI will sell assets to Essex Powerlines in the 2025 Test Year and other forecast years?

EPLC's Response:

a) Specific work has been performed by EPLC to engage with HONI to identify areas where HONI-owned assets service only EPLC customers. In these areas, extra effort is required to obtain a customer connection and at times has created significant customer connection delays where required infrastructure replacement or upgrades were necessary to connect said customer. Of the feeder sections in Amherstburg, HONI has agreed that these sections servicing only EPLC customers could be sold. EPLC and HONI are engaged in discussions to determine value of existing assets and specific network configuration edits required to satisfy HONI distribution planning. The next steps include:
    i. Meeting August 12 to review HONI expectations on sale of assets
    ii. Obtain cost proposal from HONI
    iii. Potentially provide counter proposal for asset value
    iv. Execute the purchase of assets
        1. Request invoice on sale of assets
        2. Pay agreed invoiced amount
        3. Update GIS maps indicating ownership
        4. Update Schedule D (if necessary)
        5. Update joint-use pole count

2-Staff-25

Forecast System Service Investments Ref 1: Distribution System Plan page 92
Ref 2: Distribution System Plan – Appendix A: Material Investment Narratives page 78-79

Preamble:

Essex Powerlines states that the AMI 2.0 project is expected to put downward pressure on O&M costs.

Question(s):

a) Please provide an estimate of reduction in O&M costs for each of the 2027 – 2029 forecast years.
b) Have the reductions in O&M costs been factored into the 2027-2029 forecast O&M costs?
c) Why are metering 2024 Bridge Year costs much higher than historical and forecast costs?

EPLC's Response:

a) No immediate savings are realized in 2027 as this would mark the beginning of the planning and potential roll out of AMI 2.0, the existing AMI 1.0 asset base will be maintained and incur normal expected O&M costs. In 2028, EPLC projects a reduction in O&M costs of approximately $380,000 as the implementation of AMI 2.0 meter base continues. The O&M costs for maintaining the AMI 1.0 asset base will continue at a reduced rate since the gross total assets decreases with the continued implementation of AMI 2.0.
   In 2029, EPLC projects a continued reduction in O&M costs of an additional $100,000 as the implementation of an AMI 2.0 meter base continues. The O&M costs for maintaining the AMI 1.0 asset base will continue at a reduced rate until the AMI 2.0 project is fully executed. The full execution is

estimated to be late 2030 or mid 2031; timing will be dependant on supply of hardware, integration and/or decommissioning with existing systems.

The intent of the AMI 2.0 Trials and Pilots in 2024-2025 is to work with vendors and test products to better understand the capabilities of a next generation meter asset base and better understand or quantify expected O&M savings. It is assumed that a replacement of EPLC's aging meters with new meters will materialize in a reduction in O&M costs associated with replacing failing meter assets. EPLC has experienced an increase in the annual failure rate of existing meter assets. The AMI 2.0 Trials and Pilots will also help forecast O&M costs related to maintenance of a new meter base with the expectation that the costs will be less than EPLCs's aging metering infrastructure as supported by historical trends on the current meter base performance. The AMI 2.0 Trials and Pilots will also help identify newfound efficiencies such as a reduction in data gaps or manual meter/billing reads which may also support a reduction in O&M expenditure. Additional features offered in a new meter base such as the ability to turn meters ON or OFF remotely are also expected to result in O&M savings to support the utilities routine disconnect/reconnect process for maintenance, repairs, non-payment, etc.

b) Yes, the above-described potential reductions in O&M costs associated with AMI 2.0 have been factored into the 2027-2029 forecast years.

c) The 2024 bridge year cost is significantly higher than historical and forecast costs because of the inclusion of $400,000 expenditures to conduct AMI 2.0 Trials and Pilots with prospective vendors and products. These expenditures are necessary to fully understand the features, functionality, and ultimate costs of an AMI 2.0 solution and to select the system that will provide the optimal balance of functionality, automation and opportunity to reduce O&M, and overall cost. The AMI 2.0 Trials and Pilots are considered essential to support EPLC's planned transition to AMI 2.0.

2-Staff-26

Forecast System Service Investments

Ref 1: Distribution System Plan – Appendix A: Material Investment Narratives pages 76-85 (Metering Replacement)

Preamble:

Essex Powerlines describes its forecast AMI 2.0 upgrade starting in 2027, and notes that it plans to file an ICM application with the OEB during the forecast period once it has completed the RFP and options analysis process.

Question(s):

a) Please clarify which aspects of the Metering Replacement project are included within the costs over the rebasing term to be funded through base rates (Table 3 on pg. 79), and which aspects are proposed to be funded through the ICM.

EPLC's Response:

a) All Metering costs in the Application (2025/26) are for maintenance of the existing system. Costs for AMI 2.0 will be brought forth in a separate ICM application which will contemplate any savings that can be achieved to reduce O&M included in this Application. In 2027 through 2029 in this application, EPLC has included AMI 2.0 in addition to the maintenance of AMI 1.0 through its sundown period.

2-Staff-27

Forecast System Service Investments
Ref 1: Distribution System Plan page 93

Preamble:

Essex Powerlines states in reference 1 that the Switchgear/cubicle upgrades program will replace live-front switchgear units that have failed or are at the end of their service life due failure risk.

Question(s):

a) Why is this program in the System Service category and not the System Renewal category?

EPLC's Response:

a) The switchgear/cubicle upgrade program resides in System Service as it is not a like-for-like replacement; this program is a considerable upgrade. The 'switching cubicles' that EPLC has identified in this program are Primary feeder cubicles that contain only HV elbows and no actual switchgear. Switching is conducted by de-energizing the primary legs affected and then physically moving elbows from one position to another. This upgrade program intends to replace these devices with molded vacuum interrupter (MVI) switch gear that can be monitored and operated remotely.

2-Staff-28

Forecast General Plant Investments
Ref 1: Distribution System Plan pages 11- 12
Ref 2: Distribution System Plan – Appendix A: Material Investment Narratives pages 2-8
Ref 3: Exhibit 4, page 37

Preamble:

Essex Powerlines plans to implement building and office furniture investments in the 2025 Test Year and the forecast period. Essex Powerlines' third-party building assessment is to begin in 2025. Specific investments for the 2025 Test Year include HVAC replacement and roof rehabilitation. In reference 2, Essex Powerlines states that it has replaced one of its HVAC units in 2023 and has sought quotes for additional HVAC unit replacements with similar year/model for the 2025 year. Further, Essex Powerlines had a third-party assessment performed on its roof in 2022 that has informed its rehabilitation. The remaining proposed 2025 Test Year spend is undetermined at the present time and will be an outcome of the 2025 assessment inspection.

In reference 3, Essex Powerlines has budgeted $805k in the 2024 Bridge Year related to general building expenses under OM&A. Essex Powerlines further states that 2023 actuals were $140k higher than 2022 actual due to roofing repairs. It expects a full roof recovering is necessary for 2025.

Question(s):

a) As this program is considered low priority as stated in reference 1 and the 2025 building Asset Condition Assessment is still to be done, what constitutes the substance of the $330,000 capital spend in 2025?
b) Please explain how much of the OM&A spend stated in reference 3 is budgeted for this roof recovering in 2025 and what are these estimates based on?
c) Why is the roof recovering planned and budgeted for prior to obtaining the results of the inspection?
d) When is the full inspection planned for in 2024? Why was this inspection not conducted in 2023 given the deficiencies found in the roofing earlier?

EPLC's Response:

a) The $330,000 capital spend in 2025 is made up of the following estimates:
    i. Windows replacement / upgrades for better R value $125,000
    ii. Insulation/Facade upgrades for better R value $125,000
    iii. Truck Garage additions preparations $80,000
b) None of the OM&A spend in the $805k 2024 Bridge year budget is earmarked for the roof recovering.
c) EPLC had the results of inspections from previous years dating back to 2022. EPLC has also regularly performed annual maintenance and that feedback was obtained from technicians. The March 2024 updated full roof inspection report included costs for replacement.
d) The Inspection was completed March 2024. The previous inspection in 2022 outlined the full roof replacement and therefore a 2023 report was not necessary. The 2024 inspection was completed so that EPLC could gather up-to-date costing, planning and implementation.

2-Staff-29

Forecast General Plant Investments
Ref 1: Distribution System Plan pages 93
Ref 2: Distribution System Plan – Appendix A: Material Investment Narratives page 9-20

Preamble:

Per Table 5.4-13 in reference 1, Essex Powerlines plans to invest $0.6M in IT hardware investments and $1.0M in IT software investments in the 2025 Test Year. Both hardware and software investments are considerably higher than similar investments in the 2026- 2029 forecast years as shown in reference 2. Essex Powerlines states that it replaced its servers and SANs in 2024.

Question(s):

a) What are the specific hardware investments planned for 2025?

EPLC's Response:

a) The proposed capital hardware spend in 2025 is listed as follows:
   i. General Hardware $68,083
   ii. Server Upgrade $567,360

2-Staff-30

Forecast General Plant Investments
Ref 1: Distribution System Plan – Appendix A: Material Investment Narratives page 21-26

Preamble:

In reference 1, OEB staff notes that Essex Powerlines has spent an annual average of $49k on tools over the 2018-2023 historical period. Essex Powerlines projects it will spend $100k on tools in each of 2024 and 2025. This represents over 100% increase annually in tool costs compared to the historical period. Essex Powerlines states that purchases for tools are completed on an as needed basis and that historical spending has been impacted by supply chain issues and budget reallocations to higher priority projects.

Question(s):

a) Please provide a list of tools that Essex Powerlines proposes to purchase in 2024.
b) Actual tool expenditures have been provided for the 2018-2023 historical period. Please provide the planned tool expenditure for the 2018-2023 historical period.

EPLC's Response:

a) Please find the list of proposed tools for purchase in 2024 below:
   a. Milwaukee drill combo kit x3
   b. Milwaukee 6 ton linear crimper x8 with die sets x8
   c. Milwaukee ACSR cutting jaw x8
   d. Milwaukee guy wire cutting jaw x8
   e. Regular replacement of rubber gloves (Class 0, 2 and 4)
   f. Purchase of PPE for new staff (Fall Arrest Harnesses, climbing gear, rubber gloves)
   g. Ratchet cutters x4, Crimper tool x5
   h. Pole tongs x2
   i. Super Beast x2
   j. Replacement defibrillator pads and batteries x13
   k. Purchase of 3 additional defibrillators
   l. Ladder and secondary belts for Metering x3
   m. Replacement of Batteries in Hypot machines x2
   n. Replacement of Extend-a-sticks, shotgun sticks as needed with failure

b) The planned tool expenditure for the 2018-2023 historical period is as follows:

Table 2-21: Capital Tool Budget

Capital Tool Budget

Year	Budget
2018	60000
2019	60000
2020	60000
2021	50000
2022	58000
2023	55000

2-Staff-31

Forecast General Plant Investments
Ref 1: Distribution System Plan pages 95
Ref 2: Distribution System Plan – Appendix A: Material Investment Narratives page 10

Preamble:

Essex Powerlines states that it is planning to replace multiple fleet vehicles that will be at the end of their useful life and in poor condition over the forecast period. Vehicle assessment for replacement is based on a number of factors including vehicle age, mileage, engine and PTO hours, maintenance and inspection analysis, use case requirement, and changing regulations. Essex Powerlines has provided a fleet listing of their vehicles. Vehicles #77, #80 and #10 are being replaced in the 2025 Test Year.

Question(s):

a) Did the 2021-2023 maintenance costs, and any 2024 maintenance costs not listed, for vehicles #77, #80 and #10 provide any useful life extension beyond 2024?
b) Please provide the most recent documented replacement assessments for vehicles #77, #80 and #10.
c) What are the individual estimated replacement costs for vehicles #77, #80 and #10?

EPLC's Response:

a) All dollars spent on maintenance 2021-2023 and 2024 would not extend the life of the assets (#77, #80 and #10) beyond 2024.
b) As outlined by the EPLC Fleet Purchasing policy (Exhibit 2, Appendix H), replacement is generally based on the IFRS accounting model and in doing so, have generally maintained the replacement of light trucks/vans (<4500kgs) in the 8th year (full depreciation) and heavy trucks (>4500kgs) in the 12th year (full depreciation at 11 years). Maintenance costs over the past 3 years were reviewed.
   As well, in a push to move the EPLC fleet to meet "environmental" best practices, EPLC is moving toward purchasing minimally hybrid vehicles where possible. Both #77 and #80 will be replaced with an EV or minimally, a hybrid unit.
c) The replacement cost for vehicles #77 and #80 are $80,000 per unit. The replacement cost for vehicle #10 is $560,000.

2-Staff-32

Software Capital and OM&A
Ref 1: Distribution System Plan – Appendix A: Material Investment Narratives page 10
Ref 2: Exhibit 4, page 19

Preamble:

OEB staff notes that Essex Powerlines has included software related costs in both capital and OM&A in the forecast period.

Question(s):

a) Please complete the following table on spending between on premise and cloud software investments.

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
On Premise											
	Capex	$									
	OM&A	$									
SaaS											
	Capex	$									
	OM&A	$									

EPLC's Response:

a. The breakdown between on premise and cloud investments in future years is made on a best-data-available basis for this analysis. The maintenance cost is assumed to grow year over year at 4% starting in 2024. Please see the table below outlining the breakdown:

Table 2-22: Premise and Cloud Software Investment Spending

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
On Premise											
	Capex	$199,138.00	$194,401.00	$224,633.00	$507,534.00	$466,000.00	$133,673.00	$400,000.00	$600,000.00	$100,255.00	$ 21,640.00
	OM&A	$ 95,960.21	$125,083.25	$ 66,509.99	$ 83,251.15	$107,640.00	$108,836.00	$109,955.46	$114,353.67	$115,429.94	$120,047.14
SaaS											
	Capex	$93,579.00	$54,916.00	$190,418.00	$688,013.00	$378,918.00	$908,979.00	$355,415.00	$84,700.00	$300,000.00	$300,000.00
	OM&A	$118,664.02	$ 99,929.45	$156,263.14	$176,674.51	$191,360.00	$202,124.00	$213,442.94	$221,980.66	$234,357.77	$243,732.08

School Energy Coalition (SEC)

2-SEC-12

[Ex. 2, Appendices 2-AA, 2-AB and 2-BA]

a) Please update 2-AA and 2-AB showing actuals to date for 2024, and an updated forecast for 2024 and 2025 if required.
b) If the forecast for either year changes, please update 2-BA.
c) Please provide actuals for 2022 and 2023 to the same date as provided in part a.

d) Please provide the source for the planned amounts for 2018 to 2024 (e.g. internal budget documents).

EPLC's Response:

a) See response for 2-Staff-8.
b) The forecast for 2024 and 2025 has not changed.
c) The Actuals for 2022 and 2023 to the same date as in part a) are contained in the file 'EPLC_Chapter2Appendices_IRR_20240730.xlsm'
d) The source of the planned amounts for 2018 to 2024 are the internal budget documents.

2-SEC-13

[Ex. 2, Appendix 2-BA] Please explain what assets are included in the $545,908 of Construction Work in Progress going into service in 2024, in addition to the $9,306,987 of Capex.

EPLC's Response:

The $545,908 of Construction Work in Progress is comprised of various assets that include: Transformer vaults, Transformers, Reclosers, Wood poles and framing hardware, Conduit, Aluminum and copper conductor, meters, Engineering, and Operations labour. This Work in Progress is included in the $9,306,987 that will be capitalized at the end of 2024.

2-SEC-14

[Ex. 2, DSP Tables 5.3-1 and 5.3-12]

a) Of the seven Asset Management Objectives, five use qualitative scores, i.e., the score is not based on a measurable objective. Please explain how these scores are determined.
b) Please provide the details behind the strategic objective scores provided in Table 5.3-12.

EPLC's Response:

a) While five of the scores are qualitative in nature, EPLC uses a consistent approach in the allocation of scores. For each new project type, EPLC carefully reviews similar projects and ranks the new project against already established entries, while also reviewing existing entries for accuracy and overall appropriateness.
b) The strategic objective scores shown in Table 5.3-12 are the output of an Asset Optimization tool. The scores are generated through this tool by incorporating the seven strategic objectives and their weighting as well as the risk-based analysis described in EPLC's Distribution System Plan Figure 5.3-12.

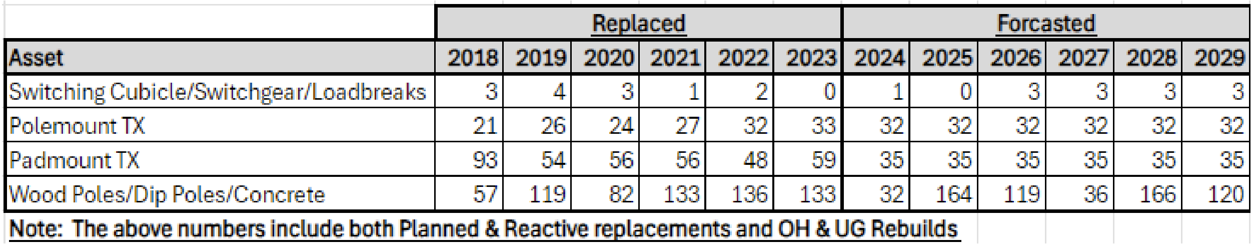
2-SEC-15

[Ex. 2, Distribution System Plan (DSP) Figure 5.3-9] For each asset included in Figure 5.3-9, please provide a table showing the number of assets replaced or forecasted to be replaced for 2018 to 2029.

EPLC's Response:

The below table includes the Replaced assets and the Forecast of assets to be replaced from 2018 to 2029.

Table 2-23: Replaced and Forecasted Assets 2018-2029



	Replaced						Forcasted					
Asset	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Switching Cubicle/Switchgear/Loadbreaks	3	4	3	1	2	0	1	0	3	3	3	3
Polemount TX	21	26	24	27	32	33	32	32	32	32	32	32
Padmount TX	93	54	56	56	48	59	35	35	35	35	35	35
Wood Poles/Dip Poles/Concrete	57	119	82	133	136	133	32	164	119	36	166	120

Note: The above numbers include both Planned & Reactive replacements and OH & UG Rebuilds

2-SEC-16

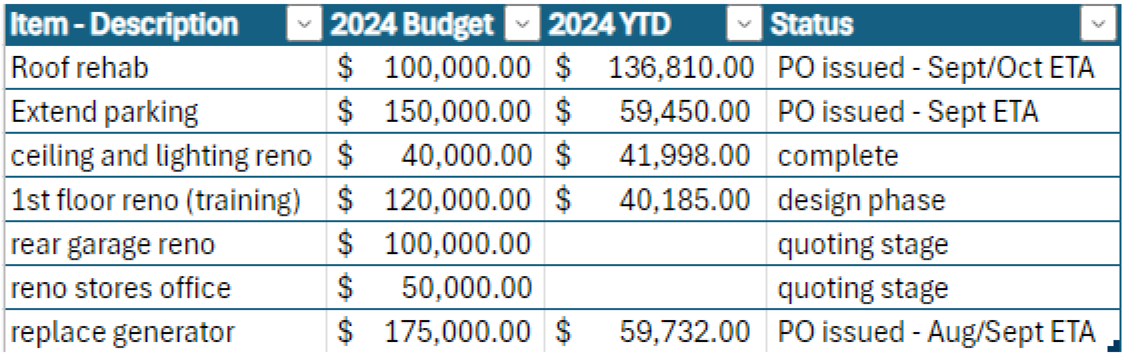
[Ex. 2, DSP, Attachment 2-A EPLC Distribution System Plan, p. 96] Essex states that it "is planning a third-party building condition assessment that is to be completed in 2025."

a) Until that assessment is completed, how has Essex determined what work is to be done and the budget for 2024 and 2025?
b) Please provide an update on the status of the planned work on the buildings for 2024 and the associated budget.

EPLC's Response:

a) EPLC reviewed current building needs in various ways. The first method was a 2022 roof assessment which helped define part of the capital plan for 2024. The roof assessment was carried out again in early 2024 to confirm the initial plan before issuing a purchase order. Items such as HVAC and Generator replacements were determined based on age of assets and maintenance. EPLC had an overall plan for office renovations which started in 2023 with elements planned for 2024 to account for growth as well. For 2025, EPLC's needs were based on additional replacement of aging assets and expansion requirements for vehicle charging.
b) Please see the below status updates:

Table 2-24: General Plant Status Updates



Item - Description	2024 Budget	2024 YTD	Status
Roof rehab	$ 100,000.00	$ 136,810.00	PO issued - Sept/Oct ETA
Extend parking	$ 150,000.00	$ 59,450.00	PO issued - Sept ETA
ceiling and lighting reno	$ 40,000.00	$ 41,998.00	complete
1st floor reno (training)	$ 120,000.00	$ 40,185.00	design phase
rear garage reno	$ 100,000.00		quoting stage
reno stores office	$ 50,000.00		quoting stage
replace generator	$ 175,000.00	$ 59,732.00	PO issued - Aug/Sept ETA

2-SEC-17

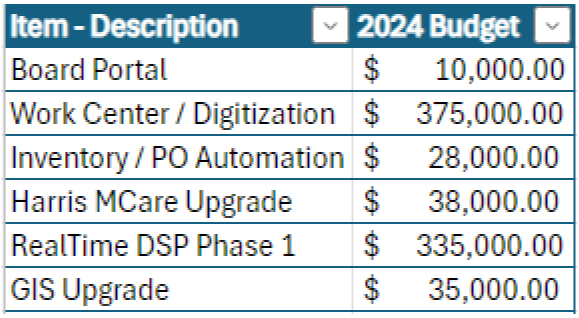
[Ex. 2, p. 35 and 41, DSP, Appendix A Material Investment Narratives, p. 9, IT Software & Hardware, and Appendix 2-AA]

a) Essex states that in 2024 and 2025 it plans to upgrade/replace its CIS, however no funds are shown in 2024 on page 35, only $909k in 2025 on page 41. What work is planned for 2024 and what is the budget?
b) Please provide details of the $885k forecast for computer software in 2024.
c) Essex has provided two quotes for the CIS work: one at $1,059k and one at $700k. How did Essex determine its 2025 budget based on these two quotes?
d) Essex states that it has partnered with three other utilities who wish to upgrade their CIS platforms and is currently in negotiations with potential vendors to reduce costs. What is the status of these negotiations?
e) Did Essex investigate obtaining CIS services from a third party? If so, please provide details. If not, why not?

EPLC's Response:

a) The CIS planning is underway however no amount will be recorded in WIP in 2024 as no funds are planned to be spent during this year. The 2025 amount for CIS is expected to be incurred and capitalized in 2025 for the project.
b) Details of the $885k forecast for computer software is as follows:

Table 2-25: Computer Software Breakdown



Item - Description	2024 Budget
Board Portal	$ 10,000.00
Work Center / Digitization	$ 375,000.00
Inventory / PO Automation	$ 28,000.00
Harris MCare Upgrade	$ 38,000.00
RealTime DSP Phase 1	$ 335,000.00
GIS Upgrade	$ 35,000.00

c) The basis for the $908,979 is the average estimated cost of the new solution plus internal system integrations, based on the 2 quotes obtained and the best information available at the time.
d) EPLC is not at an agreement stage with any vendors at this point. EPLC intends to continue to work with other utilities to confirm all vendor options and finalize the evaluation and selection process.
e) EPLC has not yet investigated CIS services from a third party outside of the current service provider. Once EPLC is in a position to finalize the CIS solution, they will assess 3rd party CIS services and the current service provider.

2-SEC-18

[Ex. 2, p. 38, DSP, Appendix A Material Investment Narratives, p. 27, Transportation & Fleet]

a) Essex plans to replace five vehicles in 2024. Does the RFP included with the Fleet Management Policy refer to the replacement of one of these vehicles? If so, which one?
b) Please provide an update on the vehicles to be purchased in 2024. When are the scheduled delivery dates?
c) Have the Purchase Orders for the four vehicles to be purchased in 2025 been issued? If not, when does Essex expect to issue them?

EPLC's Response:

a) The attached RFP included in the Fleet Management Policy does not refer to a vehicle specific to the 5 proposed for replacement in 2024. It refers to a Radial Boom Derrick (RBD) with extended cab that is not included in the list of proposed replacements.
b) Truck #108 replacement has been delivered to EPLC. The other vehicles are expected from August-October of 2024.
c) A purchase order was issued for one vehicle (Unit #110) as it is a long lead vehicle. The remaining purchase orders would be issued in 2025.

2-SEC-19

[Ex. 2, p. 37 and 42, DSP Appendix A, Material Investment Narratives, p. 27 Pole Replacements and Appendix 2-AA] Page 37 states that Essex plans to spend $488k to replace 50 poles in 2024 and Page 42 says 150 poles to be replaced at a cost of $1,426k under the Pole Replacement Program.

a) Please reconcile these dollars to those shown in 2-AA under Pole Replacement Program; i.e. $194,934 for 2024 and $1,097,247 for 2025.
b) How many wood poles does Essex plan to replace each year in 2024 to 2029?

EPLC's Response:

a) The budgeted amounts shown in 2-AA under pole replacement program ($194,934 for 2024 and $1,097,247 for 2025) are correct. This overall pole replacement budget consists of Planned Replacements and Reactive Replacements.
b) An average of 60 to 80 poles are replaced per year over the forecast period. These are planned replacements found from EPLC's results of drill testing during the preventative Maintenance inspections (pole visual, resistograph drill test, and ACA). Although included in the dollar amount, this average value (60-80) does not include any Reactive replacements as this varies year to year.

2-SEC-20

[Ex. 2, Tables 5.4-4 to 5.4-8, DSP Appendix A Material Investment Narratives, p. 65 Asset Purchase and Appendix 2-AA] Essex has forecasted $700k in 2024 and $384k in 2025 to purchase HONI assets.

a) Specifically, which assets is Essex planning to purchase each year?

b) Why does Essex think that HONI is prepared to sell these assets now, when it hasn't in 2019 to 2023?
c) Please provide the status of any discussions Essex has had with Hydro One concerning the purchase of the assets in 2024 and 2025.

EPLC's Response:

a) EPLC plans to purchase the HONI assets as follows:
    a. 2024 – 2 sections of feeder in Amherstburg
        i. 1.3 km length along Simcoe Street from Meloche Road to Fryer Street
        ii. 1.3 km length along Fryer Street from Simcoe Street to Lowes Side Road.
    b. 2025 – one section of feeder in Amherstburg
        i. 1.3 km section along Meloche Road from Alma Street to Simcoe Street.
b) Please see response to 2-Staff-24
c) EPLC and HONI are engaged in discussions to determine value of existing assets and specific network configuration edits required to satisfy HONI distribution planning. The next EPLC/HONI meeting is scheduled for August 12, 2024.

2-SEC-21

[Ex. 2, p. 73, DSP Appendix A Material Investment Narratives, p. 73 200A Network Upgrades]

a. How does Essex define its Basic Connection?
b. In the OEB Bulletin issued on August 24, 2023, on Residential Customer Connections, Service Upgrades, and newly constructed homes, it states that "38 of the 58 distributors include the necessary transformation and conductor to provide electrical capacity to accommodate a 200-amp service as part of their Basic Connection." Is Essex included in the 38 Distributors? If not, going forward does Essex intend to change its Basic Connection definition to include a 200-amp service?
c. Essex has not included any contributed capital for assets, only servicing the customer requesting the upgrade. Please explain.

EPLC's Response:

a. EPLC defines the Basic Connection as "supply and installation of up to 30 meters overhead secondary conductor to accommodate up to a 100-amp service.
b. No, EPLC is not included as part of the 38 Distributors that provide electrical capacity to accommodate a 200-amp service as part of their Basic connection service. Going forward, to support Electrification, EPLC will review and consider modifying its current Basic connection definition to include up to a 200-amp service for all new build residential single and multi-plex (duplex, tri-plex, etc.) units.
c. Contributed Capital is not included for assets because this program covers only the infrastructure upgrade required for EPLC's main network trunk, branch, or secondary buss circuits and associated hardware (transformer, secondary buss, switch/fuse holders, ect.) to support the upgrade requests for 200-amp services. This program does not include the service connection from the network trunk, branch, or secondary buss to the residential meter; these are handled on an individual basis. Each of these would have a portion of contributed capital already captured in System Access.

2-SEC-22

[Ex. 2, p. 62, DSP Appendix A Material Investment Narratives, p. 76 Metering Replacement]

a. Please provide the number of meters and gatekeepers to be purchased in 2024.
b. Please explain why Essex believes its AMI 2.0 will be eligible for ICM treatment and has chosen not to apply for an ACM as part of this Application, given that page 26 of the Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications - Chapter 3 Incentive Rate-Setting Applications, June 15, 2023 states that an ICM "is intended to address the treatment of capital investment needs that arise during the rate-setting plan …" and '…is also available for capital projects that were not included in the distributor's last filed Distribution System Plan".

EPLC's Response:

a. Meters to be purchased in 2024: (1,035). Gatekeepers to be purchased in 2024: zero (0).
b. EPLC was not in a position at the time of creating the DSP for this Application to adequately include AMI 2.0 in the Application. Initial stage investigation of the complexity, features, necessary integrations, and cost are currently underway for AMI 2.0 and those activities alongside the evolution of AMI 2.0 as a technology will influence the ultimate need and request for capital investment that will arise during the rate-setting period that is the subject of the Application.

2-SEC-23

[Ex. 2, DSP Appendix A Material Investment Narratives, p, 86 Self-Healing Grid and Appendix 2-AA]

a. Essex has obtained a NRCAN grant for $1,500,313. Please provide details on when Essex spent or plans to spend these funds, by year and by asset.
b. This project is part of System Service. Please explain how the NRCAN funds are accounted for as no capital contributions are shown for System Service in 2-AA.
c. Is any IESO DSO funding from the PowerShare project going towards this project?
d. Please explain why the budget for this project is increasing in 2024 and 2025.

EPLC's Response:

a. NRCAN contributions by year are:

   2023 - $433,596

   2024 - $613,227

   2025 - $463,807

b. The System Service Budget is shown net of any contributions. Only the portion of the project for which EPLC is responsible to bear the cost is shown in the budget.
c. No, there is no IESO-DSO funding from the PowerShare Project going toward this project.
d. For the 2024 and 2025 years, the budget is increasing as EPLC was faced with delays in manufactured goods that it planned to purchase, install and commission in year 2023. EPLC is investigating various

new technologies to implement within the Smart Renewables and Electrification Pathways Program (SREP). Due to the delays in manufacturing, EPLC has applied for, and obtained a revised budget plan from the SREP team.

2-SEC-24

[Ex. 2, DSP Appendix A Material Investment Narratives, p. 90 PowerShare DSO Project, Appendix 2-AA and EB-2024-0002, JT 1.5, Appendix B, Schedule A, and JT1.3 Appendix B] Essex has provided the following capital spend for the PowerShare DSO Project.

2023	2024	2025	2026	2027	2028	2029
260,000	371,654	150,304	153,310	156,377	159,504	162,694

a. Please indicate whether these costs are included in the Detailed Project Budget provided in Appendix B, and if so under which activity.
b. Is there any IESO contribution towards these assets?
c. The above table totals $1,413,843. Please reconcile this amount to the $1,134,209.70 shown in the Detailed Project Budget for Essex Powerlines Corporation.
d. For each project milestone, please provide the forecast budgeted costs (capital and OM&A) to be incurred by each company (Essex Powerlines, NODES AS, Essex Energy Corporation, Utilismart, and IESO), and the actual costs or revised forecast budget.
e. Please confirm that the 2023 In-Service Addition (ISA) for the DSO project equals $260k, and for 2024 ISAs are forecast to be $371,654. If not confirmed, please provide the ISAs for each year.
f. Please provide details on all other capital costs that are a result of the PowerShare project, and for each line item indicate whether IESO funding will contribute 50%. For example, Essex states that the CIS Upgrade/Replacement is critical to its requirements of becoming a DSO.

EPLC's Response:

a. A portion of the costs listed in the chart above are included in the detailed project budget. Specifically, the $371,654 in 2024 (plus a small carry over amount of $12,556 in 2025), are the amounts reflected in the budget on line items attributed to Essex Powerlines Corp, excluding lines 3.1.1, 3.1.1a, 4.2.1 and 4.2.1a.
b. Yes, the IESO Grid Innovation Fund (GIF) is supporting a 50% contribution of these assets and the amounts referenced in part a) above are net of that 50% funding.
c. The above table totals $1,413,843. EPLC has updated the table to total $1,304,786, to reflect the 2023 actual amount.

Table 2- 26: Detailed Project Budget Reconciled

2023	2024	2025	2026	2027	2028	2029
150,943	371,654	150,304	153,310	156,377	159,504	162,694

To reconcile the above table to the GIF Project budget, we must consider the revised GIF project budget and remove the Cost of Power portion. The new totals, which include revision to remove the BESS solution and now include a mobile battery solution are as follows:

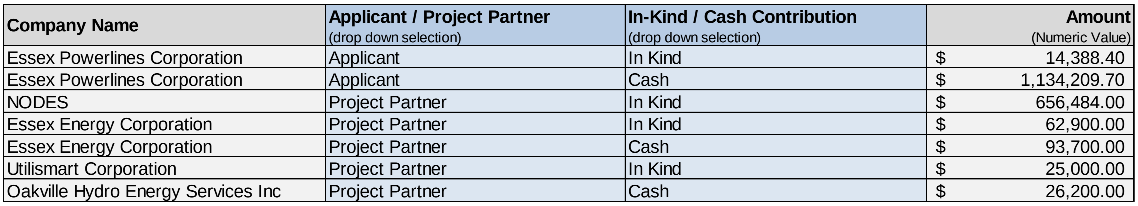
Table 2-27: Explanation of GIF Budget

EPL	in kind	14,384.40	
EPL	Cash		384,209.70
NODES	in kind	656,484.00	
EEC	in kind	62,900.00	
EEC	Cash		93,700.00
UC	in kind	25,000.00	
Oakville	Cash		26,200.00
		758,768.40	**504,109.70**

EPLC's portion of the project per the budget above and which is included in the 2023-2029 table above is $504,109.70. These numbers are in the 2023 and 2024 columns. Any amounts over and above the GIF project budget of $504,109.70 detailed in the 2023-2029 table above represent expected ongoing DSO activity costs to implement a permanent local energy market or like solution as may be realized in the market to serve future needs. The assets contemplated include measurement and verification equipment to enable local energy markets and connect potential participants.

d. A project budget amendment has been requested from the IESO to reflect changes to implementation plans with respect to the battery energy storage systems and the overall timing of project delivery. Revised allocations are detailed in the chart below. All EPLC activities planned in the GIF project are capital; minor administrative costs have been incurred in 2023 and to date in 2024. These amounts are $19,210 (2023) and $2,068 (ytd 2024).

Table 2-28: Project Plan and Budget



Company Name	Applicant / Project Partner (drop down selection)	In-Kind / Cash Contribution (drop down selection)	Amount (Numeric Value)
Essex Powerlines Corporation	Applicant	In Kind	$ 14,388.40
Essex Powerlines Corporation	Applicant	Cash	$ 1,134,209.70
NODES	Project Partner	In Kind	$ 656,484.00
Essex Energy Corporation	Project Partner	In Kind	$ 62,900.00
Essex Energy Corporation	Project Partner	Cash	$ 93,700.00
Utilismart Corporation	Project Partner	In Kind	$ 25,000.00
Oakville Hydro Energy Services Inc	Project Partner	Cash	$ 26,200.00

Based on the new proposed project plan and budget, the Milestone 1 report has been submitted but not yet approved. The amount of the Milestone 1 submission was $179,279.

e. The 2023 amount of ISA was $150,943 and EPLC confirms that the 2024 forecast amount of ISA is $371,654.

f. Aside from what is listed in the amended detailed project budget, there are no other capital costs as a result of the PowerShare project.

Vulnerable Energy Consumers Coalition (VECC)

2-VECC-6

Reference: Exhibit 2, Attachment 2-A DSP

a. Does EPLC create annual capital budgets for each of its four separate service areas? If yes, please provide the most recent budgets for each service area.

EPLC's Response:

a. No, EPLC does not create annual budgets for each of its four separate service areas. The four service areas are looked at as a single entity and the budget and plan is articulated to address by priority.

2-VECC-7

Reference: Exhibit 2, Exhibit 2, Attachment 2-A, DSP page 26

"*EPLC has met or exceeded the minimum standards in every year from 2018-2022, except for appointment scheduling in 2018 and 2022. The reason for these missed targets is due to decreased performance by contractors. Since 2010, EPLC has outsourced locate services, as this is the most cost-effective means of delivering this service. However, EPLC began to see a decrease in performance during the second quarter of 2018. EPLC contacted the contractor to address its concerns. As a result, an Action Plan was created, which included suggestions of hiring and training new resources to fulfill contractual requirements. EPLC closely monitored the compliance rate after the Action Plan was in affect and noted improvements during the last quarter of 2018. Appointment scheduling targets in 2022 were again due to challenges with third party contractors not meeting targets, specifically for locate requests. In addition, EPLC's locate provider announced their plan to cease providing locating services in southwestern Ontario. As such, EPLC has made plans to change providers with the goal of performing locates as requested and required to meet the regulatory requirements*."

a. Please provide an update as to how EPLC has reorganized so as to ensure it can meet Appointment scheduling and locate requests metrics.

EPLC's Response:

a. EPLC has continued to monitor the existing contractor closely for compliance performance. EPLC also started an agreement with another contractor to complete locates in the Lasalle area (Regular / Non-emergency) locates to allow for evaluation and less burdening of the existing contractor services. This contractor also performs locate services for a portion of the Enwin service(s) area. This will also protect EPLC if or when the existing contractor exits out of the southwestern area for locates, as they have previously stated.

2-VECC-8

Reference: Exhibit 2, Attachment 2-A DSP, page 35-36

a. Please provide revised Tables 5.2-10 and 5.2-11 for each of the four different non-contiguous service areas (i.e. Towns of Tecumseh, LaSalle, and Amherstburg, and the Municipality of Leamington).

EPLC's Response:

a. Revised Tables 5.2-10 and 5.2-11 for each of the four different non-contiguous service areas (Tecumseh, LaSalle, Amherstburg, and Leamington) cannot be shown as EPLC's OMS does not maintain separate customer count data for each individual serviced community.

2-VECC-9

Reference: Exhibit 2, Attachment 2-A DSP, page 55

Asset Class	Count	Assessment Criteria	TUL
Wood Poles	6,037	Resistograph test results, visual inspection results, service age	45
Concrete Poles	158	Visual inspection results, service age	60
Dip Poles (Primary Risers)	541	Visual inspection results, service age	45
Pad-Mounted Transformers	1,872	Visual inspection results, service age, IR results	40
Pole-Mounted Transformers	983	Visual inspection results, service age, IR results	40
Load-Break Switches	66	Visual inspection results, IR results	45
Switchgear	67	Visual inspection results, service age	30
Switching Cubicles	45	Visual inspection results, service age	30
Primary OH Conductors	180.4 km	Service age	60
Direct-buried Primary UG Cables	26.3 km	Service age	30
Primary UG Cables in Conduit	252.8 km	Service age	40

a. What percentage of poles are annual given a resistograph test?

b. What percentage of those assets subject to visual inspection are inspected on an annual basis? Are written reports completed as part of these visual inspections.

EPLC's Response:

a. The quantity of poles to be inspected varies from year to year based on the date of installation. A resistograph test is completed on 100% of the poles scheduled for inspection that year.
b. Of the assets scheduled for a visual inspection, 100% of the scheduled assets for that year are inspected. For each asset scheduled for inspection in any given year, an inspection report is completed identifying asset condition and any other concerns.

2-VECC-10

Reference: Exhibit 2, Attachment 2-A DSP, page 27-

a. Please update tables 5.2-6/7/8/9/10/11 to included 2023 results
b. Please update Figures 5.2-8 and 5.2-9 for 2023 results.

EPLC's Response:

a. Updated tables 5.2-6/7/8/9/10/11 to include 2023 results are included with response to 2-Staff-12.
b. Updated Figures 5.2-8 and 5.2-9 for 2023 results are included with response to 2-Staff-12.

2-VECC-11

Reference: Exhibit 2, Appendix B ACA Report

a. Section 4 of the BBA ACA Report makes a number of recommendations and observations related to, among other things, data gaps in EPLC's asset management systems. Please provide the Utility's response to those recommendations.
b. BAA states in its report "*Obtaining and organizing more comprehensive inspection data records would establish a stronger baseline of the asset health indices rather than being dependent on age*." (page 51). Does EPLC agree that its asset conditions are largely if not solely based on asset age?

EPLC's Response:

a. EPLC is aware of these data gaps as noted and EPLC will perform ad-hoc field visits to obtain the missing details and update the GIS mapping record. In addition, EPLC has increased the amount of data collected during inspections. This additional information will provide EPLC with more granular data to support an overall better view of asset condition. The additional fields were added to EPLC's GIS to be easily surfaced when needed.
b. EPLC does not agree that its asset conditions are largely or solely based on asset age. Although asset age is a major factor, EPLC uses additional information such as OEB/IFRS Asset Useful Life, the historical failure rate of an asset, installation conditions, historical loading for transformers, and field-testing inspection reports and results to determine overall asset condition.

2-VECC-12

Reference: Exhibit 2, Attachment 2-A DSP

Feeder	Planning Capacity (Amps)	2023 Typical Peak Load (Amps)	2023 % Utilization
23M3	627	232	37
23M4	627	345	55
23M5	627	356	57
24M7	627	269	43
24M9	627	319	51
24M10	627	292	47
56M25	627	180	29
56M26	627	347	55
56M4	627	386	62
393M24	627	325	52
393M27	627	344	55

"Approximately 60% of Ontario's greenhouses can be found in the Leamington area, and the high concentration accounts for a significant amount of forecasted load. EPLC currently has access to two feeders (M24 and M27) that service the Leamington community. During high producing months (approximately 6 months of the year), the load on the M27 feeder exceeds a comfortable level (greater than 50%). This limits EPLC's ability to transfer this load to the other feeder in the event of a failure."

a. Please identify which feeders shown in Table 5.3.6 are impacted by the PowerShare pilot project.
b. Seven of the 11 feeders listed in the above table are at greater that 50% capacity. What is the basis for the statement that feeder capacity should not exceed 50%.

EPLC's Response:

a. During the initial phase of the project EPLC has focused on two feeders, the 393M24 and the 393M27 as these feeders exceeded comfortable levels for much longer durations than any of the other feeders listed in the table. The project can include customers on all of the feeders listed above.
b. EPLC states that the load on these feeders exceeds a comfortable level (greater than 50%) and that this is considered a constraint. Specifically in the Municipality of Leamington, where EPLC has access to only two feeders, this statement is referencing that EPLC has a contingency plan in the event of a feeder outage. This plan would be to move the affected load over to an active feeder. When these feeders are operating in excess of 50%, EPLC must decide who will be restored rather than having the ability to restore the entirety of the affected feeder.

2-VECC-13

Reference: Exhibit 2, Attachment 2-A DSP, page 91-

"After completion of the project, it is expected to put a downward pressure on O&M costs in the following areas:

- The AMI 2.0 solution includes a 100% coverage model to be able to read all meters with the proposed installation.
- Less truck rolls for certain disconnects/reconnects as it can be remotely done.
- Less collectors for AMI data, meaning reduced monthly costs for backhauling meter data.
- No meter re-verifications needed for 10 years after meters are installed.,
- No more RMA's and associated costs to replace single meters which are noncommunicating."

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	208	269	332	223	190	253	787	395	403	411	419	428
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	208	269	332	223	190	253	787	395	403	411	419	428

a. Is EPLC intending to seek ICM funding in 2027 for the AMI 2.0 program?
b. If AMI 2.0 will result in lower OM&A costs, why would it not be preferable to rebase in 2028 to incorporate those savings into new rates?
c. If the program is to start in 2027, please explain why Table 3, page 79 shows spending of $787k in 2024 and continued capital spending in 2025 and 2026.

EPLC's Response:

a. Yes, EPLC intends to seek ICM funding in 2027 for the AMI 2.0 program. The 2024 bridge year cost is significantly higher than historical and forecast costs because of the inclusion of $400,000 expenditures to conduct AMI 2.0 Trials and Pilots to determine the specifications, costs, savings, and scope of the AMI 2.0 program.
b. EPLC identifies that its meter population is aging and failure rates are increasing year over year. EPLC is prudently undergoing an RFP process to identify the vendor that can provide the most suitable AMI 2.0 hardware at the best price. This will give EPLC the appropriate and necessary information to prepare an ICM application in anticipation of beginning in 2027. Waiting any longer will delay this process and cause significantly higher O&M costs for a longer duration. The transition will take several years and although it will alleviate costs associated to meter reading and other attendant cost as described in the Application, the existing cost of AMI 1.0 will not be fully removed until the end of the implementation time frame which is likely to coincide with EPLC's next rebasing in 2030.
c. In the 2024 bridge year, the cost is significantly higher than historical and forecast costs because of the inclusion of $400k expenditures to conduct AMI 2.0 Trials and Pilots to determine the specifications, costs, savings, and scope of the AMI 2.0 program. The remaining budgeted costs to make up $787k in 2024 is the portion of costs associated with maintaining the existing AMI 1.0-meter base.

There is continued capital spending in 2025 and 2026 to maintain the existing AMI 1.0 metering system. For example – the required spending to execute a Meter Reverification program of existing meter asset base as per Measurement Canada S-S-06—Sampling plans for the inspection of isolated lots of meters in service.

2-VECC-14

Reference: Exhibit 2, Attachment 2-A DSP, Appendix A Material Investments, pages 10, 17

Computer Software	($)				
	2025	2026	2027	2028	2029
General Software	74,857	76,354	77,881	79,439	81,028
CIS Upgrade	908,979				
UtiliDE Map Interface	58,816				
GIS Utility Network Design		331,510			
OMS & SCADA Enhancements		133,673		160,408	
Asset Management Deployment/Enhancements		133,673			133,673
AI Pilot Deployment		80,204			
GP Upgrade/Replacement			641,632		
Website Customer Experience				160,408	
Real Time DSP 2.0					106,939

“Overall, both platforms consist of a one-time implementation cost of approximately $700,000 to $1,100,000, which includes full integration with the Ontario provincial MDMr for meter synchronization and all aspects of billing quantity requests, responses, data editing, and other requisite data flows.”

a. What is the basis of the $908,979 CIS forecast for 2025? Has an agreement been signed for a new CIS system?
b. Did EPLC obtain any outside assistance to help determine the most effective CIS option? If so please provide any report or recommendations made by the contractor.
c. Why is it not preferrable to replace the CIS system in conjunction with the introduction of AMI 2.0 so as to ensure compatibility of these two systems?

EPLC’s Response:

a. The basis for the $908,979 is the average estimated cost of the new solution plus internal system integrations based on the 2 quotes obtained and the best information available at the time. EPLC has not signed an agreement for a new CIS.
b. EPLC did not hire an outside firm for CIS evaluations. EPLC is in discussions with other like-minded Utilities in Ontario to finalize a list of vendors with CIS solutions. EPLC is currently working through its evaluation criteria.
c. EPLC places a high value on customer experience and solution flexibility for things like future billing needs and integrations into other systems. EPLC fully intends to ensure a level of compatibility between CIS and AMI 2.0 requirements. EPLC will work very closely to include a level of flexibility for AMI 2.0 integrations as a requirement for any new CIS solution.

2-VECC-15

Reference: Exhibit 2, Attachment 2-A DSP, Appendix 2-AA

a. Please provide the details for the $735,000 in spending on “Building and Fixtures” in 2024 and indicate what amounts have been expended to-date

EPLC’s Response:

a) The details for the proposed spend on “Building and Fixtures” in 2024 can be found in the below chart:

Table 2-29: Details of Proposed Spend on Building and Fixtures

Building Plan 2024	Planned	YTD to June 30 2024
Interior Renovations, phase IV	310,000	82,183
Replace Generator	175,000	59,732
Extend Front Parking	150,000	
Roof Rehabilitation	100,000	
Total	735,000	141,915

Purchase Orders have been issued in July for the Roof Rehabilitation in the amount of $136,810 and to Extend the Front Parking Lot in the amount of $59,450. This brings the total of expensed paid and/or committed to $338,175 at July 30, 2024.

2-VECC-16

Reference: Exhibit 2, Attachment 2-A DSP, page 36- / Appendix A Material Investments

Self Healing Grid 2024 – 2028 (Appendix 2-AA)

1,574,605	1,299,659	722,096	741,289	755,678	775,502

“In 2021, EPLC was a successful applicant in Natural Resources Canada’s Renewable (NRCAN) Energy and Electricity Technologies- Smart Renewables and Electrification Pathways Program (SREP), and as such, has received a grant totaling $1,500,313 to further implement its Self- Healing Grid project. Contributions from SREP have helped accelerate the Self-Healing Grid project, with the ability to install increased reclosers and line monitors within EPLC’s distribution system.” (Material page 86)

a) For each year of the program please show the amount of any NRCAN(or other government entity) contribution.

b) Please provide the current amount spent on this program in 2024 and the current contributions.
c) What amount of self healing grid investment is necessary (if any) for the execution of the PowerShare/DRO pilot project?
d) EPLC states that "[T]*he aim of these projects is to reduce interruptions related to distribution/transmission plant owned by HONI*." (page 92 of DSP). How is the efficacy of this program being measured?

EPLC's Response:

a. NRCAN contributions by year are:
    2023 - $433,596
    2024 - $613,227
    2025 - $463,807

b. The current amount spent in 2024 is $308,514. That amount will be reduced by funding in the amount of $101,519.
c. The investments EPLC is making into the self-healing grid (SHG) concept are not directly necessary for execution of the PowerShare DSO project. These investments are primarily for load shifting capabilities within EPLC's internal network in the event of a feeder outage. These investments are also part of a Fault Locating and Isolation and System Restoration concept known as FLISR. This concept identifies a faulted section of feeder, isolates it and proceeds to restore as many customers as possible within known parameters of operation.
d. EPLC has just recently completed commissioning, throughout its serviced areas, of the devices known as reclosers, or smart switches, to be monitored and operated remotely. This is the first step in the SHG. The next step is to utilize these devices to isolate a faulted section of feeder. EPLC is working with HONI to coordinate this activity with the Transmission Station breakers at the head of the feeders that service EPLC customers. EPLC meets regularly with HONI toward this effort. Once coordination with HONI breakers is completed, EPLC will begin to monitor and record the improvements in outage statistics. EPLC is anticipating that this step is to be completed late in 2024 to early 2025.

2-VECC-17

Reference: Exhibit 2, Attachment 2-A DSP, Appendix 2-AA / Appendix A Material Investments page 27-

a. Please provide the details for the $770,000 in Transportation Equipment spending in 2024 and provide the amounts expended to date.
b. For all 2024 vehicles being purchased please indicate whether the vehicle has been delivered and if not its current expected delivery date.
c. Please update Table 1 in the Material Investments evidence's description of Vehicles to show the current vehicle inventory, the expected inventory at year end 2024 and the expected inventory at year end 2025.

EPLC's Response:

a. Please refer to exhibit 2 p.38 lines 21-26 for details on the $770,000. The updated spend on the proposed $770,000 is as follows:

Table 2-30: Updated Spend- Exhibit 2 Page 38 Lines 21-26

Transportation Plan 2024	Planned	YTD to June 30 2024	
Unit #112 - Dump Truck	105,000	101,229	Unit #112 - P.O. issued in 2023, no chasis available - Delivery date updated to October 2024
Unit #108 - 42' Single Bucket	425,000	420,637	Delivery accepted May 2024
Units #74 & #75 (Metering)	160,000	167,167	P.O. issued and delivery expected August 2024
Unit #76 (Ops)	80,000		P.O. to be issued in 2024
Total	770,000	689,033	

b. Truck #108 replacement is the only vehicle delivered at this point. The other vehicles are expected from August-October 2024.

c. See update below:

Table 2-31: Current Vehicle Inventory

Current Vehicle Inventory:

SINGLE BUCKET TRUCKS

UNIT #	Yr	DESCRIPTION
111	2014	Freightliner - 46' Single bucket Mat'l Handler
115	2021	Freightliner - 42' Single Bucket
117	2022	Freightliner - 60' Single Bucket Mat'l Handler
118	2023	Freightliner - 46' Single bucket Mat'l Handler
120	2024	Freightliner - 42' Single Bucket

DOUBLE BUCKET TRUCKS

UNIT #	YEAR	DESCRIPTION
114	2020	Freightliner - 55' Double Bucket

RBD TRUCKS

UNIT #	YEAR	DESCRIPTION
110	2013	Freightliner RBD - 50 '
113	2015	Freightliner RBD - 50 '

PICK-UP/VANS

UNIT #	YEAR	DESCRIPTION
73	2014	Dodge Ram CV (metering)
74	2016	Ram Promaster (metering)
75	2016	Ram Promaster (metering)
76	2016	Chev Silverado 2500HD (Lines)
77	2017	Chev Silverado (Lines)
78	2018	Chev Silverado 2500 with Utility Box (On-call)
79	2018	Chev Silverado 2500 with Utility Box (On-call)
80	2018	GMC Sierra 1500
81	2018	Ford F550 with Enclosed Utilty Box (UG Truck)
82	2019	Chevy Colorado (Engineering)
83	2019	Chevy Colorado (Engineering)
84	2019	Ford F350 Crew with Utility Box (UG Truck)

85	2019	Ford F150 Crew 4x4 (Lines Supervisor)
86	2022	Ford F150 Crew 4x4 Hybrid (Metering)
87	2022	Ford F150 Crew 4x4 Hybrid (H&S Supervisor)
88	2022	Chevy Colorado (Engineering)

DUMP TRUCKS

Unit #	Year	DESCRIPTION
112	2015	Ford Super Duty F550 Dump
116	2022	Ford Super Duty F550 Dump

SDP EZ Hauler 5500 Backyard RBD with Tilt Deck Trailer

	YEAR	DESCRIPTION
741	2017	SDP 17500 GVR Tilt Trailer w/ Backyard RBD

TRAILERS

UNIT #	YEAR	DESCRIPTION
730	1930	Utility Trailer
731	1992	Pole/Reel TRAILER
734	2013	Landscape Trailer

REEL TRAILERS

	YEAR	DESCRIPTION
733	1968	REEL TRAILER
743	2019	Timberland Model RCH 4.5- 72x44 Reel Trailer

POLE TRAILERS

UNIT #	YEAR	DESCRIPTION
735	1997	60' FREIBURGER POLE TRAILER
736	1997	Pole/reel trailer
744	2022	Brooks Brothers Pole Trailer

ENCLOSED UTILITY TRAILER

UNIT #	YEAR	DESCRIPTION
742	2019	MTI 716

PORTABLE TRANSFOMERS

UNIT #	YEAR	DESCRIPTION
737	1961	Portable Transformer

FRONT LOADER

	YEAR	DESCRIPTION
740	2014	Case Farmall 95C

FORKLIFT

	YEAR	DESCRIPTION
TOYOTA	2014	Toyota Forklift - Model 8FD50U

CHIPPER

	YEAR	DESCRIPTION
361	2007	Veerneer 12

Table 2-32: Expected Fleet at end of 2024:

SINGLE BUCKET TRUCKS

UNIT #	Yr	DESCRIPTION
111	2014	Freightliner - 46' Single bucket Mat'l Handler
115	2021	Freightliner - 42' Single Bucket
117	2022	Freightliner - 60' Single Bucket Mat'l Handler
118	2023	Freightliner - 46' Single bucket Mat'l Handler
120	2024	Freightliner - 42' Single Bucket

DOUBLE BUCKET TRUCKS

UNIT #	YEAR	DESCRIPTION
114	2020	Freightliner - 55' Double Bucket

RBD TRUCKS

UNIT #	YEAR	DESCRIPTION
110	2013	Freightliner RBD - 50 '
113	2015	Freightliner RBD - 50 '

PICK-UP/VANS

UNIT #	YEAR	DESCRIPTION
77	2017	Chev Silverado (Lines)
78	2018	Chev Silverado 2500 with Utility Box (On-call)
79	2018	Chev Silverado 2500 with Utility Box (On-call)
80	2017	GMC Sierra 1500
81	2018	Ford F550 with Enclosed Utilty Box (UG Truck)
82	2019	Chevy Colorado (Engineering)
83	2019	Chevy Colorado (Engineering)
84	2019	Ford F350 Crew with Utility Box (UG Truck)
85	2019	Ford F150 Crew 4x4 (Lines Supervisor)
86	2022	Ford F150 Crew 4x4 Hybrid (Metering)
87	2022	Ford F150 Crew 4x4 Hybrid (H&S Supervisor)
88	2022	Chevy Colorado (Engineering)
89	2024	Ford F150 Crew 4x4 Hybrid (Metering)
90	2024	Ford F150 Crew 4x4 Hybrid (Metering)
91	2024	Ford Escape EV (Corp Services)

DUMP TRUCKS

Unit #	Year	DESCRIPTION
116	2022	Ford Super Duty F550 Dump
119	2024	Ford Super Duty F550 Dump

SDP EZ Hauler 5500 Backyard RBD with Tilt Deck Trailer

	YEAR	DESCRIPTION
741	2017	SDP 17500 GVR Tilt Trailer w/ Backyard RBD

TRAILERS

UNIT #	YEAR	DESCRIPTION
730	1930	Utility Trailer
731	1992	Pole/Reel TRAILER
734	2013	Landscape Trailer

REEL TRAILERS

	YEAR	DESCRIPTION
733	1968	REEL TRAILER
743	2019	Timberland Model RCH 4.5- 72x44 Reel Trailer

POLE TRAILERS

UNIT #	YEAR	DESCRIPTION
735	1997	60' FREIBURGER POLE TRAILER
736	1997	Pole/reel trailer
744	2022	Brooks Brothers Pole Trailer

ENCLOSED UTILITY TRAILER

UNIT #	YEAR	DESCRIPTION

742	2019	MTI 716

PORTABLE TRANSFOMERS

UNIT #	YEAR	DESCRIPTION
737	1961	Portable Transformer

FRONT LOADER

	YEAR	DESCRIPTION
740	2014	Case Farmall 95C

FORKLIFT

	YEAR	DESCRIPTION
TOYOTA	2014	Toyota Forklift - Model 8FD50U

CHIPPER

	YEAR	DESCRIPTION
361	2007	Veerneer 12

Table 2-33: Expected Fleet at End of 2025

SINGLE BUCKET TRUCKS

UNIT #	Yr	DESCRIPTION	PLATE #
111	2014	Freightliner - 46' Single bucket Mat'l Handler	AH17507

115	2021	Freightliner - 42' Single Bucket	BN56727
117	2022	Freightliner - 60' Single Bucket Mat'l Handler	BT26334
118	2023	Freightliner - 46' Single bucket Mat'l Handler	BY95779
120	2024	Freightliner - 42' Single Bucket	BZ29675

DOUBLE BUCKET TRUCKS

UNIT #	YEAR	DESCRIPTION
114	2020	Freightliner - 55' Double Bucket

RBD TRUCKS

UNIT #	Job#	ACT	YEAR	DESCRIPTION
113	14-1404	9072	2015	Freightliner RBD - 50 '
121	23-2247	9072	2025	Freightliner RBD - 50 '

PICK-UP/VANS

UNIT #	YEAR	DESCRIPTION
78	2018	Chev Silverado 2500 with Utility Box (On-call)
79	2018	Chev Silverado 2500 with Utility Box (On-call)
81	2018	Ford F550 with Enclosed Utilty Box (UG Truck)
82	2019	Chevy Colorado (Engineering)
83	2019	Chevy Colorado (Engineering)
84	2019	Ford F350 Crew with Utility Box (UG Truck)

85	2019	Ford F150 Crew 4x4 (Lines Supervisor)
86	2022	Ford F150 Crew 4x4 Hybrid (Metering)
87	2022	Ford F150 Crew 4x4 Hybrid (H&S Supervisor)
88	2022	Chevy Colorado (Engineering)
89	2024	Ford F150 Crew 4x4 Hybrid (Metering)
90	2024	Ford F150 Crew 4x4 Hybrid (Metering)
91	2024	Ford Escape EV (Corp Services)
92	2025	Ford F150 Crew 4x4 Hybrid or equivalent (Lines)
93	2025	Ford F150 Crew 4x4 Hybrid or equivalent (Lines)

DUMP TRUCKS

Unit #	Year	DESCRIPTION
116	2022	Ford Super Duty F550 Dump
119	2024	Ford Super Duty F550 Dump

SDP EZ Hauler 5500 Backyard RBD with Tilt Deck Trailer

	YEAR	DESCRIPTION
741	2017	SDP 17500 GVR Tilt Trailer w/ Backyard RBD

TRAILERS

UNIT #	YEAR	DESCRIPTION
730	1930	Utility Trailer

731	1992	Pole/Reel TRAILER
734	2013	Landscape Trailer

REEL TRAILERS

	YEAR	DESCRIPTION
733	1968	REEL TRAILER
743	2019	Timberland Model RCH 4.5- 72x44 Reel Trailer

POLE TRAILERS

UNIT #	YEAR	DESCRIPTION
736	1997	Pole/reel trailer
744	2022	Brooks Brothers Pole Trailer
745	2025	Brooks Brothers Pole Trailer

ENCLOSED UTILITY TRAILER

UNIT #	YEAR	DESCRIPTION
742	2019	MTI 716

PORTABLE TRANSFOMERS

UNIT #	YEAR	DESCRIPTION
737	1961	Portable Transformer

FRONT LOADER

	YEAR	DESCRIPTION

740	2014	Case Farmall 95C

FORKLIFT

	YEAR	DESCRIPTION
TOYOTA	2014	Toyota Forklift - Model 8FD50U

CHIPPER

	YEAR	DESCRIPTION
361	2007	Veerneer 12

Exhibit 3- Operating Revenue

OEB Staff Interrogatories

3-Staff-33

Electric Heating
Ref 1: Exhibit 3, Attachment 3-A, page 41-42

Preamble:

Essex Powerlines expects a customer to install new electric heating equipment with incremental peak load of 2,000 kW. It has assumed that it will result in 1800 kW billing demand in a normal January (the coldest month of the year). For other months, it has assumed that the billing demand in other months would be proportionate to the ratio of HDD in that month relative to January.

A Load Factor of 21.1% is used to estimate energy use throughout the year, which is equal to the proportion of HDD which occur in January. The customer is forecasted to complete the conversion in Fall 2025. Annual consumption is multiplied by the share of HDD in September to December.

Question(s):

a) Is Essex Powerlines able to obtain any estimates of energy use and demand directly from the customer or does Essex Powerlines have access to any sources for expected energy use of similar equipment installed elsewhere?

b) What is the basis for scaling load with HDD in the month, as opposed to the equipment potentially cycling output on a much shorter duration such as minutes or hours?

c) The forecast is used to underpin rates for 2025-2029. Please explain why only load from September to December would be included.

d) Why was proportion of HDD in January used as the annual load factor?

EPLC's Response:

a) EPLC normally obtains a standard loading form that indicates the estimated load by month. In this particular case, the customers' consultant had not provided this information and only indicated that the load would be approximately 2 MW. The consultant explained that they were only in the initial design phase and would be able to provide more details once the design was completed. EPLC does not have any point loads of similar size to compare or gain data from.

b) A scaling of billed demands based on maximum hourly HDD in each month, rather than total HDD in the month, is more reflective of demands in each month. An updated load forecast with this scaling is provided as an excel model: "3-Staff-33 EPLC_LoadForecastModel GS gt Heating", which increases forecast heating-related billed demands of this customer from 2,890kW to 4,498kW. This change is included in the load forecast filed with interrogatory responses.

c) EPLC has filed a cost of service application for a 2025 test year so the load forecast reflects forecast consumption and billed demands in the 2025 test year.

d) The proportion of HDD in January aligns with the typical load factor of heating loads. For the purpose of responding to this interrogatory, an analysis was done on heating loads in each hour based on 1,800 kW in the peak hour and each other hour scaled according to HDD relative to the peak hour. In this analysis, the sum of hourly demands is 3,207,862kWh, which is close to the 3,334,330kWh forecast using the 21.1% load factor.

3-Staff-34

Electric Heating
Ref 1: Exhibit 3, Attachment 3-A, pp. 39-41

Preamble:

Essex Powerlines forecasts that 0.5% of existing customers in the residential and GS<50 classes will convert from natural gas to electricity heating each year and that 15% of new customers will have electric heating.

Question(s):

a) Please describe the basis for these estimates for electrification of heating within these customer classes. Does Essex Powerlines have any data on actual uptake to date of full or partial electrification of space heating among its new and existing customers?

b) Were these estimates informed in any way by discussion or sharing of information with Enbridge Gas Distribution regarding their forecasting assumptions around electrification of heating? If so, please describe.

EPLC's Response:

a) EPLC is only aware of a small portion of electrification within its serviced communities because unless a resident specifically defines the reason for a service upgrade, EPLC will make an assumption that the upgrade is required for and EV charger, a hot tub, or possibly a Heat Pump. EPLC would not be notified of residential conversions that include a heat pump if the service was capable of sustaining the additional load. EPLC is aware there are currently programs available for residential conversion. EPLC made a conservative estimate of 0.5% of existing customers would undergo some form of electrification. The conversion rates to electric heating are based primarily on judgement as reliable resources for trends or forecasts of electric heating adoption could not be found. This judgement considered an assumption in "Canada's Energy Future 2017 – Energy Supply and Demand Projections to 2040" (https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2018/market-snapshot-steady-growth-heat-pump-technology.html?=undefined&wbdisable=true) that 15% of new heating device purchases for both new buildings and retrofits would be heat pumps.

b) No, these estimates were not informed in any way by discussion or sharing of information with Enbridge Gas Distribution.

3-Staff-35

Electric Heating
Ref 1: Exhibit 3, Attachment 3-A, page 39, Table 48

Preamble:

Essex Powerlines forecasts additional loads from electric heating.

Question(s):

a) Essex Powerlines' estimate of kWh per customer (Table 48) associated with electric heating appears to assume the same level of end use energy efficiency in the natural gas heating equipment and the electric equipment that replaces it. Assuming that the source of (new) electric heating is most likely an electric heat pump, why did Essex Powerlines not account for the much higher end use efficiency of an electric heat pump in this calculation?

EPLC's Response:

a) Please see the submitted excel model "3-Staff-35 EPLC_LoadForecastModel Heat Pump Efficiency" which provides a revised heating load forecast that considers heat pump efficiency. The heat pump efficiency is calculated to be 2.582 so heating loads using a heat pump are reduced by a factor of 2.582.

   The efficiency figure is calculated using the average heating seasonal performance factor (HSPF) for Region IV (mid-west US) and Region 5 (Ottawa). This data is available from Natural Resources Canada (https://oee.nrcan.gc.ca/pml-lmp/index.cfm?language_langue=en&action=app.search-recherche&appliance=ASHP1_GH&_gl=1*22c7uc*_ga*MTkyNTkxMzczNi4xNjg5MDg1ODA2*_ga_C2N57Y7DX5*MTcxNTM1MDU3Ni40My4xLjE3MTUzNTA1ODAuMC4wLjA.) and includes heat pumps measured by HSPF or by HSPF2, which is an alternate calculation derived by the US Department of Energy. The average HSPF is 8.813 and this represents the ratio of energy (in BTUs) divided by total energy used in watthours. The 2.582 efficiency factor is calculated as 8.813 divided by watthours per BTU (3.413) to provide the watthours of heating generated per watthours consumed. This revision is included in the load forecast filed with interrogatories.

3-Staff-36

Conservation and Demand Management Adjustments
Ref 1: EPLC_Loadforecastmodel_COS_20240501, "Historic CDM" tab

Preamble:

Essex Powerlines makes an adjustment to its load forecast to account for the historical impact of conservation and demand management (CDM) program activity.

Question(s):

a) The CDM savings in the file EPLC_Loadforecastmodel_COS_20240501, "Historic CDM" tab, cells D118:D122, do not appear to reference the correct source data from the "CDM Framework" tab. If confirmed, please correct and update the "Historic CDM" tab and any propagating impacts on the load forecast calculations as necessary.

b) EPLC_Loadforecastmodel_COS_20240501, "Historic CDM" tab, column P notes the data sources used for information on historical CDM program savings. Did the data sources used for CDM program savings for program activity years 2011-2019 ("2011-2014 Final Results Report_EPLC" and "Participation and Cost Report - Essex Powerlines Corporation 2019 04") provide sufficient information for Essex Powerlines to calculate persistence of savings from these programs through 2025, or did Essex Powerlines need to make any assumptions regarding persistence of these CDM savings? If the latter, please describe.

c) Please confirm that the approach used by Essex Powerlines to estimate persistence of CDM savings from the IESO's 2021-2024 CDM Framework (EPLC_Loadforecastmodel_COS_20240501, "Historic CDM" tab, rows 118- 131) is based on an average of persistence assumptions for CDM program savings from earlier program years (using the data sources described in the previous question), rather than a persistence assumption specific to the 2021- 2024 CDM Framework.

d) If confirmed, is this because, to Essex Powerlines' knowledge, information on persistence assumptions specific to CDM savings from the 2021-2024 CDM Framework is not available?

EPLC's Response:

a) Confirmed. This correction is included in the revised load forecast filed with interrogatory responses.

b) The file listed in Column P "Source" refers to the source of the total First Year savings figure in Column M. The source of the persisting savings to 2025 for projects beginning in 2011 to 2014 is "2011-2014 Final Results Report_EPLC" and the source of persisting savings to 2025 for projects beginning in 2015 to 2017 is "Essex_2017_Final_Verified_Annual_LDC_CDM Program_Results_Essex_Powerlines_xlsx". Persistence of programs to 2025 of projects beginning in 2018 and 2019 were taken from the LRAMVA model files in ELPC's 2024 IRM (EB-2023-0020). Persistence to 2025 of projects beginning in those years is not provided in the "Participation and Cost Report - Essex Powerlines Corporation 2019 04" file so persistence in the LRAMVA model was estimated based on the persistence of the same or similar programs in earlier years.

c) Confirmed.

d) Yes, EPLC is not aware of a source of persistence data for the 2021-2024 framework.

3-Staff-37

Electric Vehicle Load
Ref 1: Exhibit 3, Attachment 3-A, pp. 35-39

Preamble:

Essex Powerlines forecasts the cumulative amount of electric vehicles that will be added to its service territory, and their forecast electricity consumption.

Question(s):

a) Please confirm that the data on number of new electric vehicles, by type (used in Table 40) and Canada's zero-emission vehicle sales target of 20% by 2030 (used in Table 42) exclude hybrid or plug-in hybrid vehicles that would run partially on gasoline and partially on electricity.

b) If not confirmed, please provide details, and explain why the estimates of electricity consumption per vehicle used in Table 44 are appropriate (as these estimates appear to assume that 100% of vehicle kilometres travelled would be using electricity).

c) Why does Essex Powerlines use Essex's share of the total Ontario population (0.77%) as the point estimate for Essex's share of new electric vehicles in 2026, as opposed to using Essex's actual share of new electric vehicles in 2023 (0.55%) or an average based on the historical data shown in Table 40?

EPLC's Response:

a) Not confirmed. The data in Table 40 includes "Battery electric" and "Plug-in hybrid electric" vehicles and excludes "Hybrid electric" vehicles.

b) Data used for the number of EVs is from two Statistics Canada tables: "New zero-emission vehicle registrations, quarterly" (Table 20-10-0025-01) and "New motor vehicle registrations, quarterly" (Table 20-10-0024-01). The "New zero-emission vehicle registrations, quarterly" source includes data by municipality, but not by vehicle type (either fully/partially electric or passenger/van/truck). The "New motor vehicle registrations, quarterly" source includes data by vehicle type, but only on a province-wide basis. The data reported by Statistics Canada by municipality in "New zero-emission vehicle registrations, quarterly" is combined battery electric and plug-in hybrid electric vehicles so the number of specifically battery electric vehicles is not provided by municipality. The "New motor vehicle registrations, quarterly" data is used only for the purpose of estimating the number of vehicles in EPLC's service areas by vehicle type. The estimates of electricity consumption assumed vehicles required to meet the 20% 2026 target would be battery electric, however, this target includes plug-in hybrids so the forecast should be adjusted to reflect lower expected consumption of plug-in hybrid vehicles. A revised load forecast has been submitted via excel model labelled "3-Staff-37 EPLC_LoadForecastModel PHEV Adj." which adjusts expected fuel consumption of hybrid vehicles down to 60% electricity consumption based on the share of electricity use assumed in Natural Resources Canada's 2024 Fuel Consumption Guide. The share of distance driven with electricity is not explicitly provided, so it is calculated based on the annual fuel cost per year and the stated cost of gas per litre and electricity per kWh.

c) The population of EPLC's service area was used as it is a better reflection of the service area's share of total vehicles. EV uptake has been lower than the provincial average so uptake is expected to increase over the historical share. This increase is phased in such that only 0.66% of Ontario EVs are forecast to be registered in EPLC's service area in the test year.

3-Staff-38

Conservation and Demand Management Adjustments Ref 1: Exhibit 3, page 20, Table 3-13
Ref 2: Exhibit 3, Attachment 3-A, pp. 42-43
Ref 3: EPLC_Loadforecastmodel_COS_20240501, "CDM Framework" tab

Preamble:

Essex Powerlines makes an adjustment to its load forecast to account for the expected impact of conservation and demand management (CDM) programs in the 2021-2024 CDM Framework and expected 2025 CDM program activity.

Question(s):

a) Please describe the basis for Essex Powerlines' estimate that the share of savings from the IESO's targeted greenhouse program within Essex Powerlines' service territory will be 1% of the overall savings from this program; e.g., does the 1% estimate correspond to Essex Powerlines' share of a related activity variable for the greenhouse sector, such as floor space or electricity load?

b) Please describe how, if at all, the 1% estimate takes into account the large customer greenhouse expansions in Essex Powerlines' service territory described in Attachment 3-A, pp. 42-43.

c) The in-year energy savings for 2021-2025 CDM program activity within Essex Powerlines' service territory (calculated in "CDM Framework" tab, cells L14:P14, and the cumulative savings with ½ year adjustment in cells L28:P28 of the same tab), appear to exclude savings from the Energy Affordability Program. Please confirm that savings from the Energy Affordability Program should be included in these totals, and, if confirmed, identify whether this correction has any impact on Essex Powerlines' proposed CDM adjustment for the test year or its consideration of CDM impacts in the historical load forecast data (OEB staff believe there is likely no impact). If there is an impact, please update Essex Powerlines' evidence as appropriate.

EPLC's Response:

a) EPLC is not aware of specific Targeted Greenhouse program CDM activities in its service area, however, over 60% of Ontario's greenhouses are in the Leamington area and there are additional greenhouses in the other municipalities that EPLC serves. Initial estimates of the share of Targeted Greenhouse savings that correspond to the proportion of greenhouse load in Leamington provided unreasonably high estimates of CDM. For example, if 27% of Targeted Greenhouse savings are attributed to EPLC the forecast CDM savings would exceed the total load of the General Service > 50 kW rate class. The 1% share used is a conservative estimate relative to the share of greenhouses in EPLC's service area.

b) The 1% estimate does not specifically take large greenhouse expansions into consideration.

c) The Energy Affordability Program should be included in the totals in row 14 and is corrected in the load forecast filed with interrogatory responses. This correction does not impact the load forecast as the calculations of class-specific CDM savings are based on the figures for each program and not these totals.

School Energy Coalition (SEC)

3-SEC-25

[Ex. 3, Table 3-1]

a. Please provide an update on actual customer numbers to date, for each class in 2024.
b. Please rerun the regression models using actual data to date for 2024 for all inputs.

EPLC's Response:

a. Actual customer counts for each class at the end of June 2024 is provided in the table below.

Table 3-1: Actual Customer Count for Each Class (as of end of June 2024)

Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	(HONI) Embedded Distributor
29,100	2,106	237	2,809	222	125	4

b. This forecast is provided as excel model: "3-SEC-25 EPLC_LoadForecastModel_ Actuals to date". This version includes actual customer counts, consumption, billed demands, and weather variables to June 2024. The economic variables and economic forecasts have been updated with the latest available data. Forecast customer counts have been revised by replacing forecast January to June 2024 customer counts with actual counts and applying the geometric monthly average growth rate to the June 2024 customer counts. Forecast 2025 customer counts continue to be calculated as the geometric annual average growth rate applied to forecast 2024 customer counts. CDM adjustments have been made to include half of 2024 CDM and account for loss of CDM persistence from 2023 to 2024 within the 2024 consumption dependant variables. CDM in 2024 is now included in the CDM reductions in the 'Normalized Annual Summary' tab in rows 15 and 16 and the 'CDM Adjustment' tab has been revised to remove the half-year of 2023 CDM savings included in the forecast CDM Adjustment and applying the half-year rule to 2024 CDM savings. The regressions were rerun following updates to the input data. All changes are highlighted in yellow and a summary of the differences between this version and the initial forecast is included in the 'Summary Tables' tab.

3-SEC-26

[Ex. 3, p. 44]

a. What is the basis for Essex's assumption that CDM savings in 2025 will be the same as 2024 savings?
b. Please provide the kW adjustment for CDM applied to the GS > 50 kW class for 2025 and how it was determined.

EPLC's Response:

a. Please see the response to 3-VECC-29.
b. The kW CDM adjustment is 37,655kW and is calculated in the 'CDM Adjustment' tab (beginning row 17). The adjustment is calculated using the kWh CDM savings forecast, which is the sum of EPLC's share of provincial Retrofit, Small Business, Energy Performance, Energy Management, Industrial Energy Efficiency, and Targeted Greenhouse. EPLC's share is 0.41% of provincial savings for each program except Target Greenhouse, which is consistent with its share of provincial kWh consumption. EPLC's is attributed 1% of provincial Targeted Greenhouse savings, which it considers a conservative assumption based on the proportion of greenhouses in its service area, particularly in Leamington. Note that portion of Retrofit and Small Business savings are attributed to the GS < 50 kW class. The total kWh savings for GS > 50 kW in 2025 is calculated with the half-year rule applied to 2023, full 2024 savings, and the half-year rule applied to 2025. The portion of kWh CDM savings as a share of total GS > 50 kW consumption is used to estimate the portion of kW CDM savings as a share of total GS > 50 kW demand.

Vulnerable Energy Consumers Coalition (VECC)

3-VECC-18

Reference: **Exhibit 3, pages 8 & 9**

Preamble: The Application states:

"*The COVID/weather interaction variables related to the "work from home" variable was found to be statistically significant and is used for the Residential rate class*." (page 8)

And

"*In addition to the HDD18 and CDD16 variables, the corresponding CWFH_HDD18 and CWFH_CDD16 variables were used and found to be statistically significant*." (page 9)

a. Were both variations (see page 8, lines 20-27) of the COVID/weather interaction variable tested for the Residential model?
b. If yes, why were the CWFH_HDD18 and CWFH_CDD16 variables used?

EPLC's Response:

a. Yes, both versions were tested.
b. The "work from home" (CWFH) variables were used because the model had better statistical results when those variables were included. The table below shows the t-ratios of the COVID/weather

interaction variables, the t-ratios of the main weather variables, and the adjusted R-squared for each regression. The results are similar, but in each case the model statistics are better in the version with the work from home variables.

Table 3-2: Variable Model

As Filed	t-ratio	Scenario	t-ratio
HDD18	12.62	HDD18	12.39
CDD16	30.67	CDD16	30.29
CWFH_HDD18	2.92	COVIDHDD18	2.59
CWFH_CDD16	6.70	COVIDCDD16	5.76
Adjusted R-squared	0.9798	Adjusted R-squared	0.9788

3-VECC-19

Reference: **Exhibit 3, page 12**

Preamble: The Application states:

"*Total Ontario GDP from Ontario Economic Accounts has been included as an indicator of economic activity. Measures for Ontario employment and other measures of GDP were also tested but found to be statistically less significant than Ontario GDP*."

a. Did the use of any of the other economic indicators (instead of Ontario GDP) yield a regression model with a higher adjusted R-squared value than that for the regression model used in the Application?
    a. If yes, please provide the associated regression equation for the GS<50 class, the equation's regression statistics and the resulting projected 2025 energy use.

EPLC's Response:

a. No, each other economic variable produced adjusted R-squared values that are lower than the adjusted R-squared using Total GDP from Ontario Economic Accounts (0.9370). For clarity, all economic variables were retested for the purpose of providing this response. The economic variables tested were:
    - Statistics Canada: Ontario GDP, Ontario FTEs, Seasonally Adjusted Ontario FTEs, Windsor FTEs, Seasonally Adjusted Windsor FTEs, Agriculture GDP, Crop & Animal GDP, Crop Production GDP, Agriculture Support GDP, Greenhouse GDP, Cannabis GDP, Mining General GDP, Oil & Gas GDP, and Oil & Gas Support GDP
    - Ontario Economic Accounts: Ontario GDP, Agriculture GDP, Gas GDP, and Petrol GDP

3-VECC-20

Reference: Exhibit 3, page 12

Preamble: The Application states:

"*The COVID variables were tested and found to have low statistical significance when the GDP variable was included. As such, these variables are not used in the GS<50kW model*".

a. When tested, were the COVID variables statistically significant?
    i. If yes, please provide the associated regression equation for the G<50 class, the equation's regression statistics and the resulting projected 2025 energy use.

EPLC's Response:

a. The COVID_AM and COVID_WFH variables are statistically significant at the 10% level but not the 5% level. The COVID, COVID_2020, and COVID/weather interaction variables are not statistically significant at the 10% level.
The regression coefficients and statistical results with the COVID_AM variable are provided below. Forecast 2025 consumption is 71,040,060 kWh when the COVID_AM variable is included.

Table 3-3: Variable Model Breakdown

Model 1: Prais-Winsten, using observations 2014:01-2023:12 (T = 120)				
Dependent variable: GSlt50kWh_NoCDM				
rho = 0.681342				
	coefficient	std. error	t-ratio	p-value
const	-2,996,329	757,430	-3.956	0.0001
HDD18	1,690	141	11.963	0.0000
CDD14	7,386	363	20.350	0.0000
Total_OEA	5.8	0.83	6.970	0.0000
MonthDays	124,985	14,513	8.612	0.0000
Shoulder	-109,936	40,637	-2.705	0.0079
COVID_AM	-261,464	153,064	-1.708	0.0903
Statistics based on the rho-differenced data				
Sum squared resid	3.07E+12	S.E. of regression		164,756
R-squared	0.9412	Adjusted R-squared		0.9381
F(6, 113)	202	P-value(F)		0.0000

rho	-0.057	Durbin-Watson	2.1029
Statistics based on the original data			
Mean dependent var	6,353,996	S.D. dependent var	650,494

The regression coefficients and statistical results with the COVID_WFH variable are provided below. Forecast 2025 consumption is 70,939,805 kWh when the COVID_WFH variable is included.

Table 3-4: Regression Coefficients and Statistical Results

Model 2: Prais-Winsten, using observations 2014:01-2023:12 (T = 120)				
Dependent variable: GSlt50kWh_NoCDM				
rho = 0.661989				
	coefficient	std. error	t-ratio	p-value
const	-3,192,507	738,531	-4.323	0.0000
HDD18	1,689	141	11.951	0.0000
CDD14	7,411	364	20.378	0.0000
Total_OEA	6.1	0.81	7.577	0.0000
MonthDays	124,340	14,616	8.507	0.0000
Shoulder	-112,302	40,773	-2.754	0.0069
COVID_WFH	-232,148	118,384	-1.961	0.0523
Statistics based on the rho-differenced data				
Sum squared resid	3.05E+12	S.E. of regression		164,387
R-squared	0.9414	Adjusted R-squared		0.9383
F(6, 113)	202	P-value(F)		0.0000
rho	-0.055	Durbin-Watson		2.0984
Statistics based on the original data				
Mean dependent var	6,353,996	S.D. dependent var		650,494

3-VECC-21

Reference: **Exhibit 3, page 14**

Preamble: The. Application states:

"*Total Ontario GDP from Economic Accounts has been included as an indicator of economic activity. Measures for Ontario employment and other measures of GDP were also tested but found to be statistically less significant than Ontario GDP*."

a. Did the use of any of the other economic indicators (instead of Ontario GDP) yield a regression model with a higher adjusted R-squared value than that for the regression model used for the GS>50 class?
b. If yes, please provide the associated regression equation for the GS>50 class, the equation's regression statistics and the resulting projected 2025 energy use

EPLC's Response:

a. No, each other economic variable produced adjusted R-squared values that are lower than the adjusted R-squared using Total GDP from Ontario Economic Accounts (0.8459). For clarity, all economic variables were retested for the purpose of providing this response. The economic variables tested were:
Statistics Canada: Ontario GDP, Ontario FTEs, Seasonally Adjusted Ontario FTEs, Windsor FTEs, Seasonally Adjusted Windsor FTEs, Agriculture GDP, Crop & Animal GDP, Crop Production GDP, Agriculture Support GDP, Greenhouse GDP, Cannabis GDP, Mining General GDP, Oil & Gas GDP, and Oil & Gas Support GDP
Ontario Economic Accounts: Ontario GDP, Agriculture GDP, Gas GDP, and Petrol GDP

3-VECC-22

Reference: **Exhibit 3, page 14**

Preamble: The Application states:

"*The COVID variables were tested and found to have low statistical significance when the GDP variable was included. As such, these variables were not used in the GS>50kW model*."

a. When tested, were the COVID variables statistically significant?
    i. If yes, please provide the associated regression equation for the GS>50 class, the equation's regression statistics and the resulting projected 2025 energy use.

EPLC's Response:

a) No, none of the COVID variables are statistically significant at the 10% level.

3-VECC-23

Reference: **Exhibit 3, page 17**

Preamble: The Application states:

"*The COVID variables were tested and found to have low statistical significance when the GDP variable was included. As such, these variables are not used in the Embedded Distributor model*."

a) When tested, were the COVID variables statistically significant?
    i. If yes, please provide the associated regression equation for the Embedded Distributor class, the equation's regression statistics and the resulting projected 2025 energy use.

EPLC's Response:

a) The COVID, COVID_AM, and COVID_WFH variables are statistically significant.
The regression coefficients and statistical results with the COVID variable are provided below. The AdjWindsor_FTE and Fall variables are not statistically significant when the COVID variable is included so they have been removed from the regression. Forecast 2025 consumption is 32,856,995 kWh when the COVID variable is included.

Table 3-5: Regression Coefficients and Statistical Results with COVID Variable

Model 1: Prais-Winsten, using observations 2015:11-2023:12 (T = 98)				
Dependent variable: EDkWh2016				
rho = 0.502912				
	coefficient	std. error	t-ratio	p-value
const	2,396,036	65,380	36.648	0.00000
HDD14	718	165	4.355	0.00003
CDD16	3,327	376	8.859	0.00000
COVID	(373,795)	80,573	(4.639)	0.00001
Statistics based on the rho-differenced data				
Sum squared resid	3.01E+12	S.E. of regression		178,993
R-squared	0.7040	Adjusted R-squared		0.6946
F(6, 113)	43	P-value(F)		1.65E-17
rho	-0.1096	Durbin-Watson		2.2122
Statistics based on the original data				
Mean dependent var	2,630,298	S.D. dependent var		323,420

The regression coefficients and statistical results with the COVID_AM variable are provided below. The AdjWindsor_FTE and Fall variables are not statistically significant when the COVID_AM variable is included so they have been removed from the regression. Forecast 2025 consumption is 32,734,924 kWh when the COVID_AM variable is included.

Table 3-6: Regression Coefficient and Statistical Results with COVID-AM

Model 2: Prais-Winsten, using observations 2015:11-2023:12 (T = 98)				
Dependent variable: EDkWh2016				
rho = 0.533558				
	coefficient	std. error	t-ratio	p-value
const	2,394,125	66,274	36.125	0.00000
HDD14	707	165	4.299	0.00004
CDD16	3,222	373	8.633	0.00000
COVID_AM	(630,284)	138,474	(4.552)	0.00002
Statistics based on the rho-differenced data				
Sum squared resid	2.95E+12	S.E. of regression		177,247
R-squared	0.7097	Adjusted R-squared		0.7004
F(6, 113)	44	P-value(F)		7.14E-18
rho	-0.1121	Durbin-Watson		2.2166
Statistics based on the original data				
Mean dependent var	2,630,298	S.D. dependent var		323,420

The regression coefficients and statistical results with the COVID_WFH variable are provided below. Forecast 2025 consumption is 33,535,523 kWh when the COVID_WFH variable is included.

Table 3-7: Regression Coefficients and Statistical Results with COVID-WFH

Model 3: Prais-Winsten, using observations 2015:11-2023:12 (T = 98)				
Dependent variable: EDkWh2016				
rho = 0.568795				
	coefficient	std. error	t-ratio	p-value

const	1,359,559	545,567	2.492	0.01449
HDD14	808	163	4.955	0.00000
CDD16	3,659	378	9.681	0.00000
Fall	131,741	51,131	2.577	0.01157
AdjWindsor_FTE	5,843	3,175	1.840	0.06895
COVID_WFH	(400,392)	109,143	(3.669)	0.00041
Statistics based on the rho-differenced data				
Sum squared resid	2.69E+12	S.E. of regression		171,138
R-squared	0.7349	Adjusted R-squared		0.7205
F(6, 113)	30	P-value(F)		5.05E-18
rho	-0.0891	Durbin-Watson		2.1768
Statistics based on the original data				
Mean dependent var	2,630,298	S.D. dependent var		323,420

3-VECC-24

Reference: Load Forecast Model, Historic CDM Tab (Column P)

and CDM Framework Tab

a) Please provide copies of the reports/documents used as the sources for the historic 2011-2019 CDM results (per Historic CDM Tab (Column P).

b) The CDM Framework Tab provides a table setting out EPLC's percentage of total provincial energy use. Please provide similar tables setting out: i) EPLC's residential class energy use as a percentage of total provincial residential energy use; ii) EPLC's GS<50 energy use as a percentage of total provincial GS<50 energy use and iii) EPLC's GS>50/LU energy use as a percentage of total provincial GS>50LU energy use.

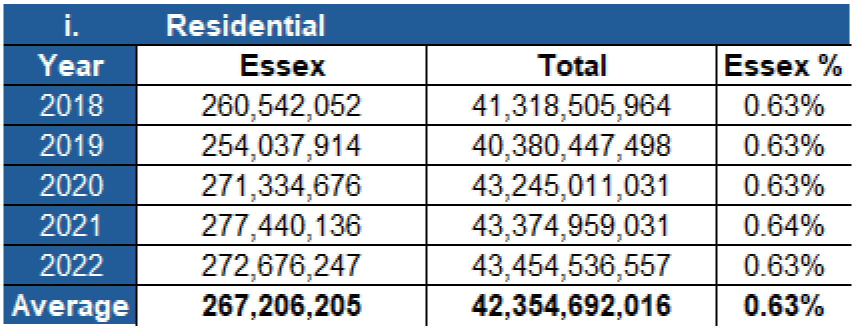
c) Please explain why it is reasonable to assume that 1.0% of 2021-2024 CDM Framework savings from Targeted Greenhouse initiatives will occur in EPCL's service area (per CDM Framework Tab).

EPLC's Response:

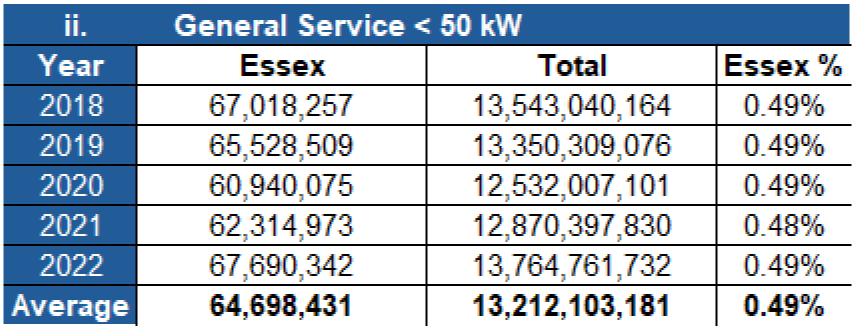
a) The files are provided as excel model "3-VECC-24a - 2011-14 Persistence Report_Essex Powerlines with Summary", excel model "3-VECC-24b Essex_2017 Final_Verified Annual_LDC CDM_Program Results_Essex_Powerlines", and excel model "3-VECC-24c Participation and Cost Report - Essex Powerlines Corporation - 2019 04". As described in 3-Staff-36, Column P refers to the reference file with total First Year savings and does not mention the 2017 Final Verified savings file. This file includes persistence savings information for programs implemented in 2015-2017.

b) The requested information is provided in the below tables:

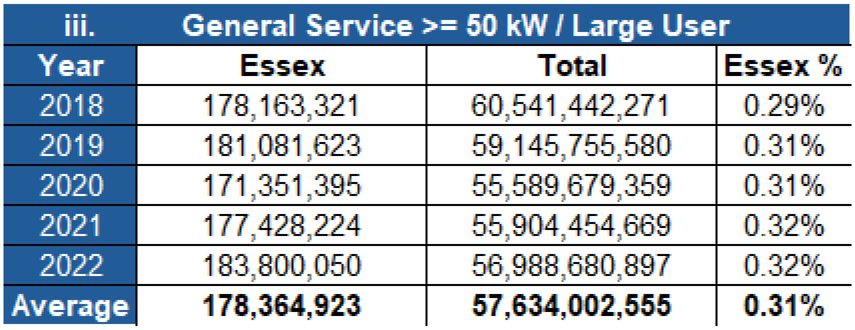
Table 3-8: EPLC’s Percentage of Total Provincial Energy Use



i.	Residential		
Year	**Essex**	**Total**	**Essex %**
2018	260,542,052	41,318,505,964	0.63%
2019	254,037,914	40,380,447,498	0.63%
2020	271,334,676	43,245,011,031	0.63%
2021	277,440,136	43,374,959,031	0.64%
2022	272,676,247	43,454,536,557	0.63%
Average	**267,206,205**	**42,354,692,016**	**0.63%**



ii.	General Service < 50 kW		
Year	**Essex**	**Total**	**Essex %**
2018	67,018,257	13,543,040,164	0.49%
2019	65,528,509	13,350,309,076	0.49%
2020	60,940,075	12,532,007,101	0.49%
2021	62,314,973	12,870,397,830	0.48%
2022	67,690,342	13,764,761,732	0.49%
Average	**64,698,431**	**13,212,103,181**	**0.49%**



iii.	General Service >= 50 kW / Large User		
Year	**Essex**	**Total**	**Essex %**
2018	178,163,321	60,541,442,271	0.29%
2019	181,081,623	59,145,755,580	0.31%
2020	171,351,395	55,589,679,359	0.31%
2021	177,428,224	55,904,454,669	0.32%
2022	183,800,050	56,988,680,897	0.32%
Average	**178,364,923**	**57,634,002,555**	**0.31%**

c) Please see 3-Staff-38.

3-VECC-25

Reference: Exhibit 3, pages 30-31

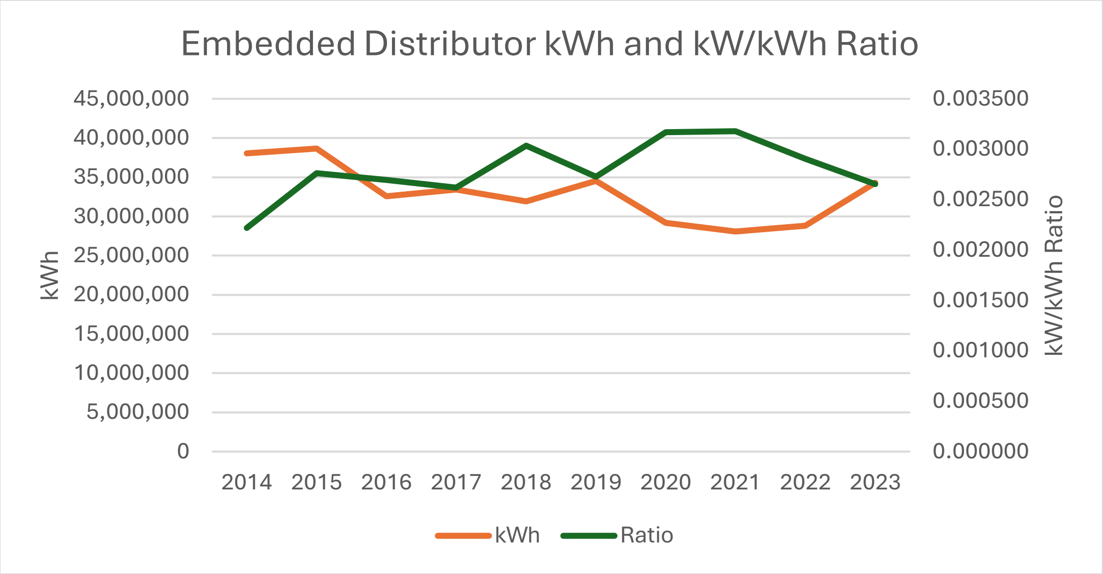
Load Forecast Model, kW Forecast Tab

a) Please confirm that for the 5-year average kW/kWh ratio from 2019 to 2023.was also used for the Street Lighting class.

b) Please explain why the 2023 kW/kWh ratio was used for the Embedded Distributor class.

EPLC's Response:

a) EPLC confirms that for the 5-year average kW/kWh ratio from 2019 to 2023 was also used for the Street Lighting class.
b) The 2023 kW/kWh ratio better reflects the Embedded Distributor's loads at forecast 2025 consumption than an average ratio.
Embedded Distributor kWh consumption varies inversely with the kW/kWh ratio. In general, changes in consumption and demand are directionally the same over time, but consumption changes are greater than demand changes. Consumption in 2025 is forecast to be similar to 2023 consumption, which is higher than consumption in recent years, so the 2023 kW/kWh ratio produces a kW forecast that is aligned with this level of consumption. Using an average ratio such as a 5-year average ratio would result in a forecast in which consumption in 2025 is within 0.12% of 2023 consumption but demand is 10.16% higher than 2023 demand.



3-VECC-26

Reference: **Exhibit 3, Attachment 3-A, page 38**

Preamble: The Attachment states:

"*The allocation of incremental consumption is estimated based on judgement as Essex does not have these details by rate class. The allocations and allocated incremental consumption by EV type to each class is provided in Table 46*."

a) What information was used to inform EPLC's/Elenchus' judgement as to the allocation of EV energy use to customer classes?

EPLC's Response:

a) Elenchus reviewed the "Updated forecasts of vehicle charging needs, grid impacts and costs for all vehicle segments" report prepared by Dunsky for Natural Resources Canada (https://natural-resources.canada.ca/energy-efficiency/transportation-alternative-fuels/resource-library/electric-vehicle-charging-infrastructure-for-canada/25756). Considerable judgement was required to allocate EV energy use to customer classes as EPLC does not have information on existing EV ownership by rate classes and where EVs are charged. The allocation to rate classes considers that some charging of EVs owned by Residential customers (10%) would be done at the premises of non-Residential customers.

3-VECC-27

Reference: **Exhibit 3, Attachment 3-A, page 39**

Preamble: The Attachment states:

"*Residential and GS<50 kW heating loads are forecast for both existing connections and new customers. It is assumed that 0.5% of existing customers will convert from natural gas to electricity heating each year and that 15% of new customers will have electric heating. Annual forecast heating loads for the Residential and GS<50 kW class are provided in Table 49 and Table 50, respectively*."

a) For each of EPLC's Residential and GS<50 customer classes, what percentage of EPLC's current (2023) customers use electric heating?
b) For new Residential and GS<50 customers connecting in 2021-2023, what percentage (for each class) used electric heating?
c) What was the basis for EPLC's/Elenchus' assumptions that: i) 0.5% of existing customers will convert from natural gas to electricity heating each year and ii) 15% of new customers will have electric heating?
    i. Also, please clarify whether the assumption was the 15% of new customers will have electric heating or the adoption of electric heating in for new customers will be 15 percentage points higher than historically experienced.

EPLC's Response:

a) EPLC does not have information of the percentage of customers that use electric heating.
b) EPLC does not have information of the percentage of customers that use electric heating.
c) The conversion rates to electric heating are based primarily on judgement as reliable resources for trends or forecasts of electric heating adoption could not be found. This judgement considered an assumption in "Canada's Energy Future 2017 – Energy Supply and Demand Projections to 2040" (https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2018/market-snapshot-steady-growth-heat-pump-technology.html?=undefined&wbdisable=true) that 15% of new heating device purchases for both new buildings and retrofits would be heat pumps.
    i. The assumption is that electric heating adoption is 15 percentage points higher than historic experience. The historic level of electric heating adoption is reflected in actual data and this 15% is incremental.

3-VECC-28

Reference: **Exhibit 3, Attachment 3-A, page 42**

Preamble: The Attachment states:

"*Table 55 calculates the forecast billed kW for this customer. The customer is forecast to have a peak demand of 1,800 kW in a typical January with 609 HDD and peak demands are prorated in each other month based on the month's share of total HDD. Forecast billed kW in the test year is the sum of these demands*."

a) Given that peak demand represents the highest demand in the month, why is the peak demand prorated based on each month's share of total HDD?
    i. Why isn't it reasonable to assume that on the coldest day in each month that has an HDD value the peak heating load will be 1,800 kW?

EPLC's Response:

a) Please see 3-Staff-33 part b. The load forecast has been revised to prorate demand to the maximum hour HDD in each month.
    i. The coldest day in a typical year will be lower than the maximum coldest day so it is assumed that the customer will not require the maximum capacity in each year. For reference, the maximum coldest hour in recent years had 40.7HDD compared to the average maximum coldest hour of 35.56HDD. The 10% adjustment from maximum demand to average annual peak demand is roughly aligned with the 12.7% lower average peak HDD relative to maximum peak HDD.

3-VECC-29

Reference: **Exhibit 3, Attachment 3-A, page 44**

Preamble: The Attachment states:

"*CDM activities have been forecast based on EPL's share of consumption within the province and the IESO's 2021-2024 Conservation and Demand Management Framework. The table below provides a summary of the 2021-2024 Framework and EPL's allocation of savings. CDM savings in 2025 are not available so the savings are assumed to be the same as 2024 savings*."

a) Please explain why it is reasonable to assume that the provincial target for CDM savings in 2025 will be equal to the 2024 target as opposed to being equal to the average annual savings for the 2021-2024 CDM Framework overall.

EPLC's Response:

a) The assumption that targeted CDM savings in 2025 will be equal to 2024 is a conservative assumption based on two statements in the IESO's 2024 Annual Planning Outlook. Page 6 includes a comment that "Electricity demand growth is tempered by **an increased CDM program forecast** and elevated levels of economic uncertainty" and on page 26 it states "This Forecast assumes the delivery of CDM programs will continue after the current Framework. It is assumed that the annual savings of new programs will be consistent with levels forecasted for the enhanced 2021-2024 CDM Framework, on **a proportion of gross demand basis**." [Emphasis added]

Both statements suggest CDM savings will be somewhat higher than the 2021-2024 CDM Framework, but without any indication of the magnitude of an increase forecast CDM was kept at 2024 amounts. A 2021-2024 average would result in a decline in forecast CDM.

Exhibit 4- Operating Costs

OEB Staff Interrogatories

4-Staff-39

Unionized labour
Ref 1: Exhibit 4, page 43

Preamble:

Essex Powerlines states,

"Costs and Models in this application have not been updated to reflect any anticipated new contractual obligations; EPLC has continued with the above noted 2% increase at this time. The most recent round of negotiations is currently underway and at such time as negotiations are successfully concluded, EPLC will update all affected schedules to reflect those new increase amounts. It is expected that this will be completed during the interrogatory or draft rate order phase of the Application process."

Question(s):

a) Please provide an update on the bargaining process and update the evidence as necessary.

EPLC's Response:

a) The bargaining process is not yet concluded. Conciliation is scheduled for late July and no outcome from that is known at the time of this response. EPLC is planning to update evidence once a new contract has been concluded.

4-Staff-40

Regulatory Costs
Ref 1: Exhibit 4, page 60

Preamble:

Essex Powerlines states,

"EPLC's cost associated with the creation of this Cost of Service application which is currently estimated at $557,830. This cost includes legal, consulting, administrative, and intervenor costs. Consulting costs include costs for customer engagement (Innovative Research $22.5k), DSP (Metsco $100k) and third-party application

support and review (Elenchus $60k). EPLC also included $300k in incremental costs associated to other resources required to generate the required information in support of this Application."

Question(s):

a) Please explain any assumptions used to forecast the $557,830 one-time regulatory cost for the 2025 cost of service proceeding (e.g., how many intervenors, written vs oral hearing, etc.).
b) Please explain what is included in the $300k incremental costs.

EPLC's Response:

a) The forecast of $557,830 is comprised of both actual costs incurred to 2023 and anticipated costs to be incurred in the 2024 bridge year. Assumptions included $160,000 for consultant costs, $54,000 for legal costs, $35,000 for intervenor costs and $309,000 for other resource costs.
b) The $309,000 forecasted for other incremental costs relate to direct support from EPC in the preparation of this application.

4-Staff-41

Compensation
Ref 1: Exhibit 4, page 43
Ref 2: Exhibit 4, page 42

Preamble:

In reference 1, Essex Powerlines states that it has been participating in the MEARIE salary survey since 2011.

Essex Powerlines further states,

"In 2020, EPLC also engaged Marjorie Richards & Associates Ltd. to complete a third-party review and development of Job Description and Job Evaluation of each management and non-union position, against the Hay Point methodology. The Job Evaluations resulting from this engagement were used to ensure alignment between job requirements and EPLC's compensation structure and pay bands."

In reference 2, Essex Powerlines states,

"There is an increase of $257,300 in 2022 Actual versus 2021 Actual results. This is the result of the outcomes of the job evaluation process that was undertaken in 2020 and the associated alignment of pay structures and pay bands with job requirements as reviewed using the Hay point methodology and in alignment with the MEARIE Survey results."

Question(s):

a) Please explain how Essex Powerlines compared to the industry average as demonstrated by the MEARIE survey and review by Majorie Richards & Associates Ltd.
b) What changes were made to the executive compensation as a result of the MEARIE survey and review by Marjorie Richards & Associates Ltd.

c) What was the percentage increase in compensation attributed to the Hay Point methodology and MEARIE survey in 2022 in reference 2?

EPLC's Response:

a) EPLC was below the industry average in several job categories when compared to the MEARIE Survey and review by Marjorie Richards & Associates.
b) The Salary of the CEO was changed to meet the average as published in the MEARIE Salary Survey and the incentive pay for this position was increased to align with the P50 metric in the MEARIE Salary Survey.
c) 65% of the increase in compensation is attributable to the Hay Point methodology and MEARIE survey in 2022.

4-Staff-42

FTEs
Ref 1: Exhibit 4, page 53
Ref 2: Exhibit 4, page 50
Ref 3: Chapter 2 Appendices, Tab 2K

Preamble:

In reference 1, Essex Powerlines states,

"In 2024 EPLC is also adding a full-time Control Room position as planned in the re- establishment of full control room services in collaboration with Welland Hydro. This position will support the EPLC control room initiative from a day-to-day operations perspective and be supported through collaborative undertaking."

In reference 2, Essex Powerlines states,

"Beginning in 2024 and fully included in the 2025 Test Year, EPLC has included four new positions that reflect a re-alignment of previous positions and were not considered in EB-2017-0039. These new positions are enablers for EPLC to adapt to the evolving needs in the areas of technology adoption and advancements in cyber threats, while maintaining the appropriate focus on customer relations and support."

OEB staff notes that the 4 new positions listed by Essex Powerlines are Director of Customer Experience, IT Cybersecurity Analyst, Distribution System Engineer, and Purchasing Manager.

In reference 3, total FTEs have increased by 4 in 2025 and 2 in 2024.

Question(s):

a) Please clarify which position listed in reference 2 was hired in 2024.
b) Please explain the 2 new FTEs in 2024.
c) What is Essex Powerlines historical churn rate with respect to FTE positions?

EPLC's Response:

a) Hiring for the IT Cybersecurity Analyst (title has been changed to IT Cybersecurity Supervisor) and the Purchasing Manager (title has been changed to Purchasing and Inventory Supervisor) are planned for 2024. Neither position has been filled at this time, although the Purchasing and Inventory Supervisor hiring process is underway as the job has been posted.

b) The IT Cybersecurity Supervisor position is required to provide the necessary focus on ever-increasing risk of cyber security threats that is being emphasized as a requirement by the OEB.
The Purchasing and Inventory Supervisor position is required to better plan EPLC's material requirements to achieve best pricing and manage the ongoing supply chain constraints.

c) EPLC had a fairly consistent number of FTEs in 2018-2019 but has experienced challenges with recruitment and retention of staff during the Covid-19 years, which saw an overall decrease of approximately 3 FTEs between 2019-2023. EPLC has now nearly arrived at the point of full recovery of these positions by the midway point of the 2024 bridge year.

4-Staff-43

Shared Services and Corporate Cost Allocation Ref 1: Exhibit 4, page 58
Ref 2: Affiliate Relationship Code

Preamble:

In reference 1, Essex Powerlines has the following table for the 2025 Test Year:

Name of Company		**Service Offered**	**Pricing Methodology**	**Price for the Service**	**Cost for the Service**
From	**To**				
				$	**$**
EPLC	Municipalities of Tecumseh, Amherstburg	Water billing & collection	Flat monthly service charge	$329,600	
EEC	EPLC	Engineering support services	Hourly rate		$302,870
EEC	EPLC	IT Development Services	Hourly rate		$41,229
EPLC	EEC	Streetlight Maintenance, MSP	Fully allocated cost	$142,539	
EPC	EPLC	HR Services, Finance Services, Executive Services, Board Costs	Fully allocated cost		$1,421,985
UC	EPLC	Wholesale Settlement Services, Meter Reading Services	Negotiated contract with market tested rates		$398,417

As per reference 2,

"Where a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility sells to an affiliate, the utility shall charge no less than its fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost shall include a return on the utility's invested capital. The return on invested capital shall be no less than the utility's approved weighted average cost of capital."

Question(s):

a) Please clarify on what basis Essex Powerlines determined that cost-based pricing in accordance with the Affiliate Relationship code applies to the services listed in reference 1 where fully allocated costs are not used.
b) Please confirm that fully allocated costs as listed in the table from reference 1 are inclusive of a return on the utility's invested capital no less than the utility's approved weighted average cost of capital.

EPLC's Response:

a) EPLC uses market prices for those services where the fully allocated cost pricing methodology is not being used. Specifically, water billing and collection services are per contract with the municipalities. Hourly rates for Engineering support and IT services are quoted by EEC and considered during EPLC's annual budget process. Wholesale settlement and meter reading services are per contract using market tested rates.
b) EPLC confirms that fully allocated costs as listed in the table from reference 1 are inclusive of a return on EPLC's invested capital no less than the utility's approved weighted average cost of capital.

4-Staff-44

Cable Locates
Ref 1: Exhibit 4, page 25

Preamble:

In reference 1, Essex Powerlines has budgeted $325k for the Cable Locates program in 2024 and $564k in 2025.

Question(s):

a) Please explain the reason for the material increase between the Bridge and Test Years.

EPLC's Response:

a) Locate costs have varied year-over-year during the historical period. The budgeted $325k in the bridge year represents the impact of announced higher interest rates and the resulting assumed reductions in large scale residential developments. EPLC anticipates the impact of higher interest rates to be lessened in the Test Year yielding a renewed investment in large scale residential developments returning to slightly higher than 2019-2023 historical average.

4-Staff-45

Meter Operations
Ref 1: Exhibit 4, page 27

Preamble:

Essex Powerlines states,

"There is an increase in Meter Operations in the 2025 Test Year, as EPLC's AMI 1.0 meter population is now approaching end of life and the second round of seal reverifications will be necessary beginning in 2025. The cost for that activity plus ongoing and increasing meter failures due to age are the contributing factors to this increase."

Question(s):

a) Please explain how much has been budgeted for reactionary work in 2025 for this program. Explain any assumptions used to develop the forecast for 2025.
b) How much of the $175k budgeted for 2024 is related to meter failures? Please explain all assumptions used.

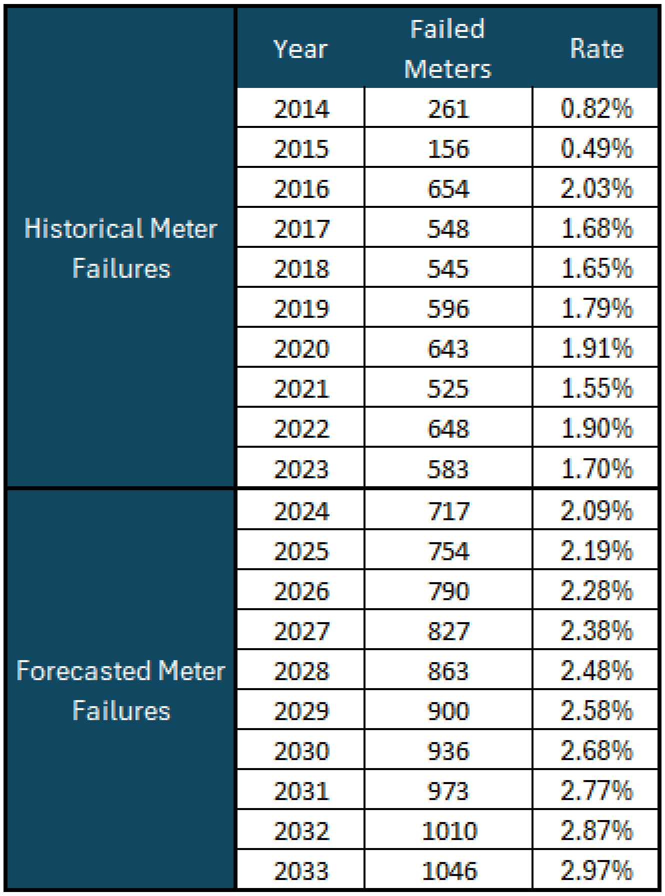
EPLC's Response:

a) A total of $94,565 has been budgeted for 2025 reactionary work in the Metering Operations program.

   Assumptions:

   i. EPLC compiled 10-years of meter failure records to forecast a trend in meter failures expected in 2024 onward, see Table-1 below:

Table 4-1: Meter Failure Records



	Year	Failed Meters	Rate
Historical Meter Failures	2014	261	0.82%
	2015	156	0.49%
	2016	654	2.03%
	2017	548	1.68%
	2018	545	1.65%
	2019	596	1.79%
	2020	643	1.91%
	2021	525	1.55%
	2022	648	1.90%
	2023	583	1.70%
Forecasted Meter Failures	2024	717	2.09%
	2025	754	2.19%
	2026	790	2.28%
	2027	827	2.38%
	2028	863	2.48%
	2029	900	2.58%
	2030	936	2.68%
	2031	973	2.77%
	2032	1010	2.87%
	2033	1046	2.97%

ii. EPLC validated that there is correlation between meter age and failure rates. EPLC's AMI 1.0 meters fail more frequently as they age. see Table-3. EPLC assumed the trend in meter failures would continue based on the age distribution of meter base see Table-2.

Table 4-2: Meter Age Distribution

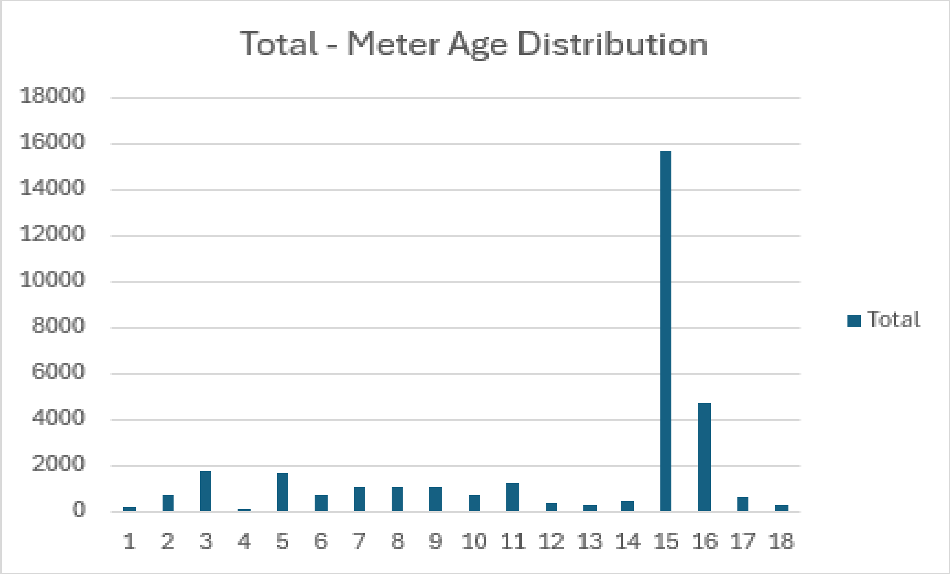
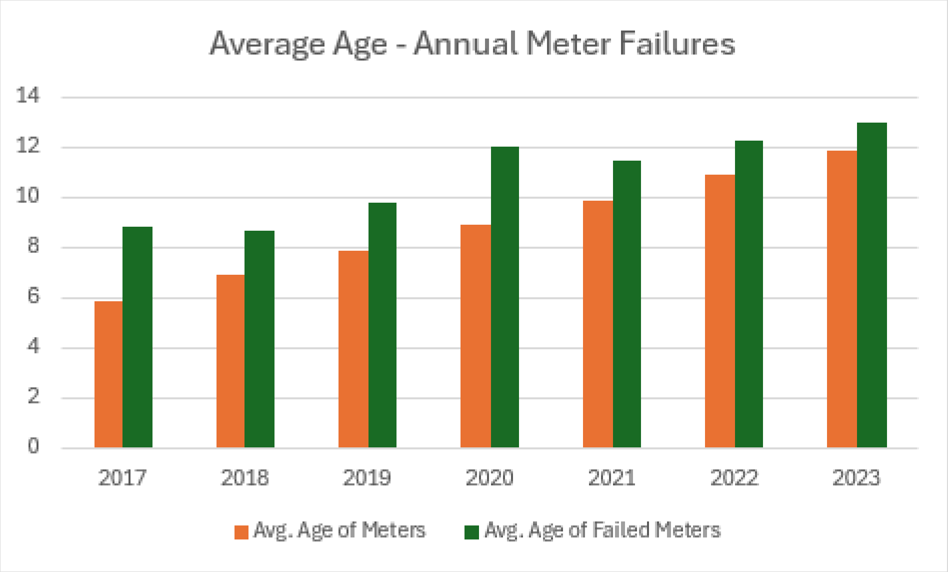


Table 4-3: Average Age- Annual Meter Failures



b) A total of $45,480.50 of the $175k budgeted for 2024 is related to meter failures. The assumptions for 2024 are described similarly as 2025. Based on historical data shown in Table-1,-2, & -3, EPLC assumed the trend in meter failures would continue based on the age distribution of AMI 1.0 meters.

4-Staff-46

Customer Collections
Ref 1: Exhibit 4, page 37

Preamble:

In reference 1, Essex Powerlines states,

"There is an increase of $221,280 in the 2025 Test Year when compared to the 2024 Bridge Year. This is the result of increased spending on collection efforts and disconnection activities as we work closely alongside customers as we manage costs between collection efforts and bad debt expenses."

Question(s):

a) Please elaborate on the collection efforts that are forecasted in the 2025 Test Year and resulted in a material increase over 2024. Please state all assumptions that were included in the forecast.

EPLC's Response:

Customer collections encompass a broad range of customer service activities up to and including actual customer collections efforts. Emphasis is placed on customer outreach with a goal of building strong relationships with customers. The allocation of staff time between billing and collecting activities is reviewed periodically and at least annually.

4-Staff-47

Audit, Legal & Consulting
Ref 1: Exhibit 4, page 39

Preamble:

Essex Powerlines has included additional legal costs related to PowerShare and how to incorporate appropriate new distribution models into planning within the Audit, Legal and Consulting OM&A program category. The 2024 budget is $442k and 2025 budget is $249k.

Question(s):

a) Please explain how much of the budget in 2024 and 2025 is attributed to legal costs associated with Powershare? Please provide a breakdown of these costs and explain any assumptions included in the forecast.
b) Please confirm if the IESO is contributing 50% to the legal costs related to Powershare through the Grid Innovation Fund. If so, are the above noted costs in question (a) net of the IESO's Grid Innovation Fund?
c) How much of these costs does Essex Powerlines expect to incur annually between 2026-2029?

EPLC's Response:

a) Legal costs associated to PowerShare were not budgeted in either 2024 or 2025. Legal costs amounting to approximately $20,000 have been incurred to date in 2024 specifically to address concerns related to EPLC application EB-2024-0096 (PowerShare DVA Application).

b) No legal fees were included in the project proposal of budget for PowerShare and as such the IESO is not contributing 50% of the legal costs.
c) EPLC does not expect to incur legal costs annually related to PowerShare between 2026-2029.

4-Staff-48

FTEs
Ref 1: Exhibit 4, page 53

Preamble:

In reference 1 Essex Powerlines states,

"Specifically, EPLC hired 2 additional Design Technicians and they were employed for all of 2023 in anticipation of 2 upcoming retirements. There was an extended period of overlap to permit adequate training for the role, especially considering that the 2 existing long-term staff were expected to retire at approximately the same time early in 2024."

Question(s):

a) Please explain why the costs have not normalized in 2024 given the 2 retirements compared to 2023.

EPLC's Response:

a. These costs have not normalized in 2024 for two reasons:
    i. The two new Distribution Design Technologists hired in 2023 chose to resign their positions; the first one in late December 2023 and the second in early January of 2024. This prompted EPLC to seek two replacements on short order, the first of which started mid-March 2024 and the second near the end of April 2024.
    ii. The first retirement was announced for March 31, 2024 and EPLC was able to have this retiree return on contract to the end of May to support the two new hires. The second Distribution Design Technologist's retirement is currently pending with no firm date at this time.

4-Staff-49

Inflationary increase
Ref 1: Exhibit 4, page 16, Table 4-4

Preamble:

In reference 1, Essex Powerlines shows the year over year increase in total OM&A expenses. In 2025, Essex Powerlines has assumed inflation for budgeting purposes of 2%.

Question(s):

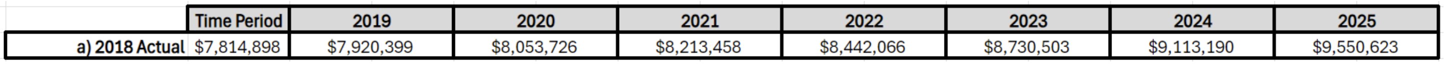
a) Please provide an annual inflation estimate for total OM&A expenses using the 2018 actual OM&A as the base and escalating each year thereafter using the adjusted inflation value (OEB inflation less stretch factor).

b) Please provide an annual inflation estimate for total OM&A expenses using the 2018 OEB-approved OM&A as the base and escalating each year thereafter using the adjusted inflation value (OEB inflation less stretch factor).

EPLC's Response:

a) Please see the table below for annual inflation estimates for OM&A expenses using 2018 Actual OM&A as the base.

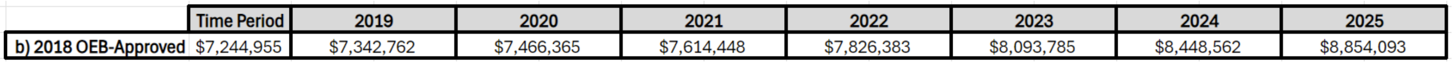
Table 4-4: Annual Inflation Estimates for OM&A



	Time Period	2019	2020	2021	2022	2023	2024	2025
a) 2018 Actual	$7,814,898	$7,920,399	$8,053,726	$8,213,458	$8,442,066	$8,730,503	$9,113,190	$9,550,623

b) Please see the table below for annual inflation estimates for OM&A expenses using 2018 OEB Approved amount as the base.

Table 4-5: Annual Inflation Estimates for OM&A using 2018 OEB Approved Amount



	Time Period	2019	2020	2021	2022	2023	2024	2025
b) 2018 OEB-Approved	$7,244,955	$7,342,762	$7,466,365	$7,614,448	$7,826,383	$8,093,785	$8,448,562	$8,854,093

4-Staff-50

Chapter 2 Appendices
Ref 1: Chapter 2 Appendices, Tab 2-JA

Preamble:

OEB staff has noted an error in reference 1. The cells U18 and V18 should reference F25 and G25 respectively.

Question(s):

a) Please reconcile the error and file an updated model.

EPLC's Response:

EPLC confirms that this cell reference has been updated as instructed and an updated model has been filed.

4-Staff-51

OPEBs

Ref 1: Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2, Cost of Services, p31

Preamble:

Chapter 2 of 2024 Filing Requirements notes that:

A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for in the last OEB-approved rebasing application, and for historical, bridge and test years. The most recent actuarial report(s) must be included in the pre-filed evidence and be reconciled with the pension and OPEBs amounts (as applicable).

OEB staff notes that the above evidence cannot be found.

Question(s):

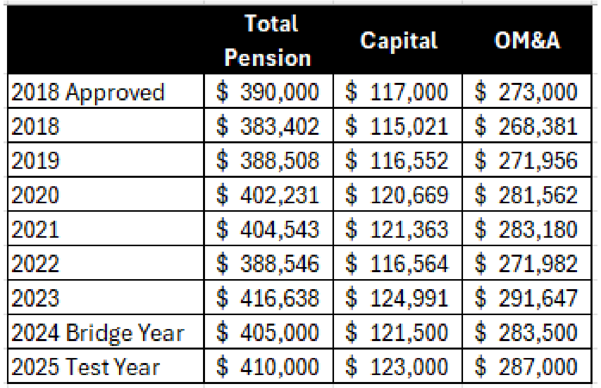
a) Please provide the following schedules as noted in reference 1.
   i. A breakdown of the Pension & OPEBs amounts between capital and OM&A from the last OEB-approved to the Test Year, year-by-year.
   ii. A reconciliation of the 2023 actuarial report with the Pension & OPEBs amounts.

EPLC's Response:

a.)

i. OPEB amounts are 100% OM&A. The breakdown of OMERS pension amounts between capital and OM&A is as follows:

Table 4-6: OMERS Pension Breakdown



	Total Pension	Capital	OM&A
2018 Approved	$ 390,000	$ 117,000	$ 273,000
2018	$ 383,402	$ 115,021	$ 268,381
2019	$ 388,508	$ 116,552	$ 271,956
2020	$ 402,231	$ 120,669	$ 281,562
2021	$ 404,543	$ 121,363	$ 283,180
2022	$ 388,546	$ 116,564	$ 271,982
2023	$ 416,638	$ 124,991	$ 291,647
2024 Bridge Year	$ 405,000	$ 121,500	$ 283,500
2025 Test Year	$ 410,000	$ 123,000	$ 287,000

Table 4-7: Reconciliation of 2023 Actuarial Report with Pension and OPEBs

ii.

Description	2018 OEB Approved	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Defined Benefit obligation, opening balance	2,615,750	2,474,873	2,602,840	2,732,165	2,843,718	2,674,090	2,185,279	2,114,700	2,137,500
Current service cost	70,900	63,447	65,500	59,938	70,600	67,000	51,600	53,200	55,600
Interest Cost	85,700	87,349	96,200	92,728	63,900	72,700	107,300	96,800	97,100
Plan Improvements	-	-	-	367,995	-	-	-	-	-
Actuarial losses (gain)	-	(121,529)	174,025	(274,462)	(152,128)	(434,266)	(49,479)	-	-
Benefits Paid	(101,300)	(101,300)	(206,400)	(134,700)	(152,000)	(194,245)	(180,000)	(127,200)	(165,100)
Net Liability / Asset	2,671,050	2,602,840	2,732,165	2,843,718	2,674,090	2,185,279	2,114,700	2,137,500	2,125,100

School Energy Coalition (SEC)

4-SEC-27

[Appendices 2-JA, 2-JD, and 2-K]

a. Please update Appendices 2-JA, JD and K for 2024 actuals to date and provide actuals for the same date in 2022 and 2023.
b. Please provide the internal budget for OM&A for 2019 to 2023.

EPLC's Response:

a. Appendices 2-JA, 2-JD and 2-K have been updated with June 30 actuals for the years 2024, 2023 and 2022.
b. The internal budgets for OM&A for 2019 to 2023 are as follows:

2019 - $8,835,081

2020 - $8,204,800

2021 - $7,929,065

2022 - $8,146,547

2023 - $8,412,430

4-SEC-28

[Ex. 4, p. 18] Essex states that "charges for material costs for locate work, when performed by EPLC staff, increased".

a. Please explain under what circumstances Essex does its own locates and why costs are higher when it does.
b. Please confirm that Essex has included any increased costs related to the Getting Ontario Connected Act and does not plan to make use of the generic DVA account set up by the OEB.

EPLC's Response:

a. EPLC does not do its own locates, EPLC utilizes a third-party service provider to perform locate services. The statement refers to this third-party service provider increase in costs.

b. EPLC can confirm that any increased costs related to the Getting Ontario Connected Act has been included and that EPLC does not plan to make use of the generic DVA account set up by the OEB.

4-SEC-29

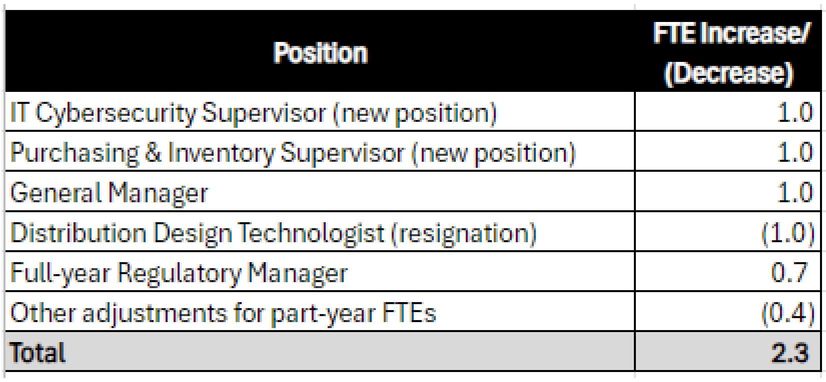
[Ex. 4, Tables 4-6, 4-17, 4-18 and Appendix 2-K]

a. Table 4-17 highlights the new positions to be added in 2025; one in Engineering (Design Analysis), one in Corporate Services (Purchasing Manager), one in IT (Cybersecurity), and one in Billing & Collecting (Director of Customer Service). These additions do not agree with the increases shown in Table 4-18. Please reconcile.
b. Table 4-18 shows an increase in FTEs of 2.3 for 2024. Please provide details on these new positions and provide an update on hiring.
c. Table 4-6 shows a total increase from 2018 approved to 2025 for Salaries, Wages and Benefits of $1,436k. Appendix 2-K shows an increase in total compensation allocated to OM&A for the same period of $609k. Please explain the difference.

EPLC's Response:

a. Overall, with the exception of the President & Chief Executive Officer who does not form part of EPLC's staff complement, Table 4-17 and Table 4-18 both contain 51 FTEs. Per Table 4-17, Billing & Collecting has 12 FTEs and Engineering & Metering has 7 FTEs. Per Table 4-18, Billing & Collecting has 9 FTEs and Engineering & Metering has 10 FTEs. The difference is the 3 meter technicians who are reflected in different departments in each table.
b. Between 2023 and 2024 bridge year, FTEs increased from 45 to 47.3. The table below details this 2.3 FTE increase.

Table 4-8: FTE Increase



Position	FTE Increase/ (Decrease)
IT Cybersecurity Supervisor (new position)	1.0
Purchasing & Inventory Supervisor (new position)	1.0
General Manager	1.0
Distribution Design Technologist (resignation)	(1.0)
Full-year Regulatory Manager	0.7
Other adjustments for part-year FTEs	(0.4)
Total	**2.3**

c. The higher Salaries, Wages and Benefits costs in Table 4-6 are due to allocations for executive and non-executive salaries from EPC and future benefits expenses which are not included in Appendix 2-K.

4-SEC-30

[Ex. 4, Table 4-29 and Appendix 2-N]

a. Appendix 2-N for 2025 shows total costs of services provided to Essex from affiliates is $2,164,501 and Table 4-29 shows $2,175,812. Please reconcile.
b. Please confirm that the Totals shown in Table 4-29 have added both services provided by Essex and provided to Essex, and do not show the net.
c. Please explain how Essex has determined the cost of each of the services supplied to EEC; i.e. the nature of the work and the number of hours forecast.
d. Please provide the details of the HR Services, Finance Services, Executive Services, and Board Costs provided by EPC.
e. Please provide all shared services agreements Essex has with its affiliates related to services provided to and from its affiliates.
f. Please complete Appendix 2-N showing both the price and cost of services, and using the Corporate Cost allocation section for those EPC costs which are allocated to Essex.

EPLC's Response:

a) EPLC has reconciled the amounts in Appendix 2-N and table 4-19 and confirms that Appendix 2-N reflects the correct amounts. The revised table is below:

Table 4-9: Revised Shared Services Variances

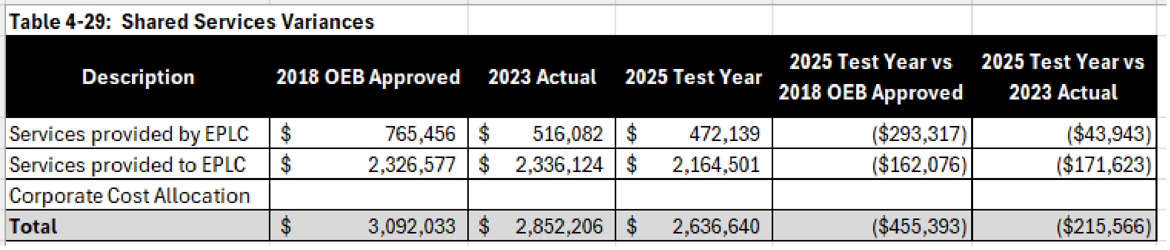


Table 4-29: Shared Services Variances

Description	2018 OEB Approved	2023 Actual	2025 Test Year	2025 Test Year vs 2018 OEB Approved	2025 Test Year vs 2023 Actual
Services provided by EPLC	$ 765,456	$ 516,082	$ 472,139	($293,317)	($43,943)
Services provided to EPLC	$ 2,326,577	$ 2,336,124	$ 2,164,501	($162,076)	($171,623)
Corporate Cost Allocation					
Total	$ 3,092,033	$ 2,852,206	$ 2,636,640	($455,393)	($215,566)

b) EPLC confirms that totals shown in Appendix 2-N do not show net values.
c) EPLC prepares bills to EEC based on time charged to the associated job in ELPC's job costing system for streetlight maintenance and MSP services. Invoices are prepared for these services to include fully burdened cost plus 9% markup.
d) **HR Services**: all aspects of compensation, benefit and pension management for EPLC. Additionally, HR services include management payroll administration and management of various labour relations and employment matters.

Finance Services: the provision of oversight and assistance in all areas of annual financial budgeting, audit and tax planning and reporting. Additional Financial Services include coordination of debt financing, liaising with institutional and other lenders, administration of audits by other parties, assistance where required with regulatory and other accounting matters.

Executive Services: various oversight and interaction activities between the Distributor and various stakeholders including Municipal Shareholders, various government bodies such as the OEB, IESO and other interested parties such as the Electricity Distributors Association, Grid Smart City, other Ontario LDCs in support of collaboration, and EPLC customers.

Board costs: Board costs incurred by EPC and included in the corporate cost are those fees only for the EPLC Board of Directors charged with providing governance over the process and activities of EPLC.

e) Copies of MSA's for shared services and Agreements are attached as Attachment C, redacted for confidentiality.

f) Appendix 2-N has been updated to reflect the EPC allocated cost under the Corporate Cost Allocation section, and the 2024 number was updated to the correct value.

4-SEC-31

[Ex. 4, p. 18, Table 4-6 and Appendix 2-JC] Table 4-16 shows a total increase of $979k from 2018 approved to 2025 for Materials. Page 18 provides an explanation stating that a change in the inventory handling procedure results in a one-time increase in material costs.

a. Please confirm that Essex is attributing $979k-$300k-$100k-$50k = $529k to this one-time change,
b. Please provide which OM&A Programs, as outlined in Appendix 2-JC, include the material costs.
c. When was the change in the procedure made?
d. Please explain what Essex means by a one-time increase.
e. Please show where the corresponding decrease in capital is included.

EPLC's Response:

a. The $529k increase in materials from 2018 approved to 2025 is not the result of the change in the inventory handling procedure. The largest contributor to the increase in materials occurs in the 2024 bridge year and 2025 test year. In 2024, the increase is attributable to the combination of locates and vegetation management. The 2024 budget for locates is lower than 2023 actuals and is the result of an expected reduction in development based on economic conditions. The 2025 budget for locates is an accurate reflection of anticipated expenditures in that year based on an expected return to a more normal level of development activity and falls in line with actual costs incurred in 2023. This budget for locates is offset by a 2023 variance in vegetation management costs where the budget was located in the cost driver for materials but the actuals were recorded to outside services.
b. The Operation and Maintenance OM&A Programs include the material costs related to the change in inventory handling procedure.
c. The change in procedure was made in 2019.
d. The change in material handling procedure involved taking the material costs out of inventory and charging these costs to O&M expense when the materials were placed on a truck. These materials would then be charged to specific jobs as they were used. The one-time increase is related to that movement of costs out of inventory to O&M expense.
e. There is no decrease in capital, as the impact of the change in material handling procedure involved only a one-time decrease to inventory and a corresponding increase to O&M expense.

4-SEC-32

[Ex. 4, p. 18, Table 4-6 and Appendix 2-JC]

Table 4-6 shows a total increase from 2018 approved to 2025 for Customer Billing and Collecting of $432k. Page 18 provides an explanation related to one-time costs that are not recurring.

a. Please explain where this one-time cost is shown in Appendix 2-JC under Billing and Collecting.
b. Appendix 2-JC does show Billing and Collecting increasing by $458k, primarily because Customer Collections increased by $408k. In the same period, Bad Debts have decreased by 50%. Please provide the business case for the increase in Collections.

EPLC's Response:

a. Although the one-time costs are not recurring, they were not incurred simultaneously as the various changes required by the OEB were phased in over a period of time between 2019-2023 (2019 – OREC; 2020 – Covid-19 billing changes; 2023 – Ultra Low Overnight Rate). Furthermore, costs incurred varied depending upon the complexity of the required billing changes.
b. The increase in Collections is required to not only manage customer collection efforts but to also enhance customer outreach and build strong customer relations, with an end goal of lower and better management of bad debts expense.

4-SEC-33

[Ex. 4, p. 40 and 41 and Appendix 2-JC]

a. Please explain General Building Expenses OM&A increasing from 2023 to 2025 at the same time Essex has increased its capital spending on Buildings.
b. Please explain why Regulatory Costs in 2025 did not decrease by the one-time cost of $79,927, as described in 2024 on page 40.

EPLC's Response:

a. General building expenses OM&A have increased from 2023 to 2025 primarily due to increases in computer hardware and software maintenance, which are included as part of the General Building Expenses OM&A envelope.
b. EPLC's 2023 actuals included labour costs for one regulatory staff person for the entire year plus one regulatory staff person for one-third of the year, resulting in 2023 being a year with lower-than-normal expenses. In the 2024 bridge year and 2025 test year, EPLC's budget includes provision for a staff complement of two FTEs for the entire years.

4-SEC-34

[Ex. 4, p. 4, Table 4-16, Appendices 2-JC and 2-K] Page 41 states that Administration & HR Expenses "relates to the compensation of administrative staff not specifically allocated to a specific job or activity as well as the HR related expenses associated with all EPLC staff." Appendix 2-JC shows Administration & HR Expenses increasing by $1,689k from 2018 OEB-Approved. Page 41 shows a $1,449k increase, and states this is "the result of increases in wages due to inflation, progressions and a job evaluation process that was carried out." Additional job positions are also contributing to an increase in this work program.

a. Please confirm that the increase for this program from 2018 OEB-Approved to 2025 is $1,689k.
b. Please provide details of which employees are included in this program with reference to Table 4-16.
c. Please explain how this program, which does not include all employees, can increase by more than the compensation allocated to OM&A for the same period.

EPLC's Response:

a. Confirmed.
b. This program includes 1.5 FTE in Engineering & Metering; 0.5 FTE in Operations; 1 FTE in Corporate Services; 2.8 FTE in IT; 3 FTE in Finance & Regulatory; and 1 FTE in Administration.
c. This work program also includes the corporate cost allocation for services provided to EPLC.

4-SEC-35

[Ex. 4, p. 10] Please provide the total OM&A for the DSO PowerShare project in each of the following years from 2022 to 2025.

EPLC's Response:

OM&A attributable to the DSO PowerShare project in each of the following years is:

2023 – $19,210

2024 – $2,068 for the year to date

No costs were directly attributed to PowerShare OM&A in 2022 and it is anticipated that any 2024 costs for the balance of the year and 2025 costs will not be material. The work within the project is being administered as part of regular utility distribution activities.

Vulnerable Energy Consumers Coalition (VECC)

4-VECC-30

Reference: Exhibit 4, page 14

"*To date, 451 EV charging stations have been, or are in the process of being, installed within the Windsor-2 Essex Region*."

a) How many EV charges (specify level 1 and 2) are being installed in the EPLC franchise?

EPLC's Response:

a) In EPLC service territory, 51 level 2 EV chargers have been installed. Data is not available on Level 1 EV chargers as these do not require any special connections; Level 1 chargers plug into any regular

120V receptacle very much like a lamp or coffee maker. Level 2 chargers require a specialized 240V, 60A receptacle or connection.

4-VECC-31

Reference: Exhibit 4, pages 29-

a) EPLC's operations OM&A budget has increased from a projected $1,505,256 in 2024 to $1,890,101 forecast to be spent in 2025 -. an increase of over 25%. At the same the Utility proposes to increase its system renewal capital budget from an estimated $2,087,889 in 2024 to $3,213,536 – an increase of over 53%. Please explain why, if the Utility is replacing a higher proportion of existing assets, it also requires a higher than usual increase in maintenance spending on smaller base of older existing assets.

EPLC's Response:

a) The increase in the Operations OM&A of $384,845 ($1,890,101 - $1,505,256) between the 2025 Test Year and the 2024 Bridge Year is due to increases in Locates costs of $237k and an increase in Meter Operations of $147k.

Locates costs have increased when compared to 2024 yet are in line with 2023 actuals. For 2024 EPLC anticipated a lower trend on developments primarily from conversations with developers indicating that their projects would be delayed by six to twelve months, and they cited the increased lending rate as the cause. For the forecast 2025 year, EPLC is anticipating the level of developments and activity to have a resurgence to slightly higher than average level as seen in historical years 2019 to 2023.

There is an increase in Meter Operations in the 2025 Test Year, as EPLC's AMI 1.0 meter population is now approaching end of life and the second round of seal reverifications will be necessary beginning in 2025. The cost for that activity plus ongoing and increasing meter failures due to age are the contributing factors to this increase.

The increase in the system renewal capital budget of $1,125,647 ($3,213,536 - $2,087,889) is related to the Pole Replacement program and not to the Meter Operations or Locates activities.

4-VECC-32

Reference: Exhibit 4, pages 33-

a) Does Essex do its own tree trimming?
b) During the years 2018 through 2022 EPLC average vegetation control budget averaged $443m. What would be the impact of maintaining that as the vegetation budget for 2025?

EPLC's Response:

a) No, EPLC relies on a 3rd party service provider to perform annual and reactive tree trimming.

b) Maintaining a $443k budget for 2025 is a difference of approx. $71,612 which would prevent EPLC from following an established program and would have a negative impact on SAIDI and SAIFI.

4-VECC-33

Reference: Exhibit 4, page 18 /page 24 4.3.2.1

“*Additionally, charges for material costs for locate work, when performed by EPLC staff, increased by over $300k during this time period*”

a) Does EPLC do its own locates?
b) In 2024 EPLC estimates locate costs as $325,207. In 2025 this the forecast is an increase to $564,506. Why is the increase so large between these two years?

EPLC’s Response:

a) No, EPLC does not do its own locates. EPLC relies on a 3rd party service provider to perform locates.
b) For 2024, EPLC expected the level of developments and activity to return to slightly less than 2022 historical levels. Developments in EPLC service territory have been impacted and slowed, in part, due to increased interest rates. For the forecast 2025 year, EPLC is anticipating the level of developments and activity to have a resurgence to slightly higher than average level as seen in historical years 2019 to 2023.

4-VECC-34

Reference: Exhibit 4, page 17, Tables 4-5, 4-6

Primary Cost Drivers 2018-2025 Total	
Salaries, Wages and Benefits	$1,436,326
Materials	$978,718
Customer Billing and Collecting	$432,406
Computer Systems, Hardware and Software	$177,393
Building	$69,500
Administrative	$86,297
Outside Services incl tree trimming	($347,369)
Total	**$2,833,271**

a) EPLC identifies “Materials” as one of the main cost drivers of the increase in OM&A in 2025. What program are these costs reported under in Appendix 2-JC (OM&A Programs Table)?

EPLC's Response:

Please see response to 4-SEC-31.

4-VECC-35

Reference: Exhibit 4, page 43

Effective Date Wage Increase Agreement Expiry		
April 1st, 2019	1.75%	March 31st, 2024
April 1st, 2020	2.00%	
April 1st, 2021	2.00%	
April 1st, 2022	2.00%	
April 1st, 2023	2.00%	

"The most recent round of negotiations is currently underway and at such time as negotiations are 18 successfully concluded, EPLC will update all affected schedules to reflect those new increase amounts. It 19 is expected that this will be completed during the interrogatory or draft rate order phase of the 20 Application process."

a) Please provide an update on the current status of the IBEW labour negotiations.

EPLC's Response:

a) See response to 4-Staff-39.

4-VECC-36

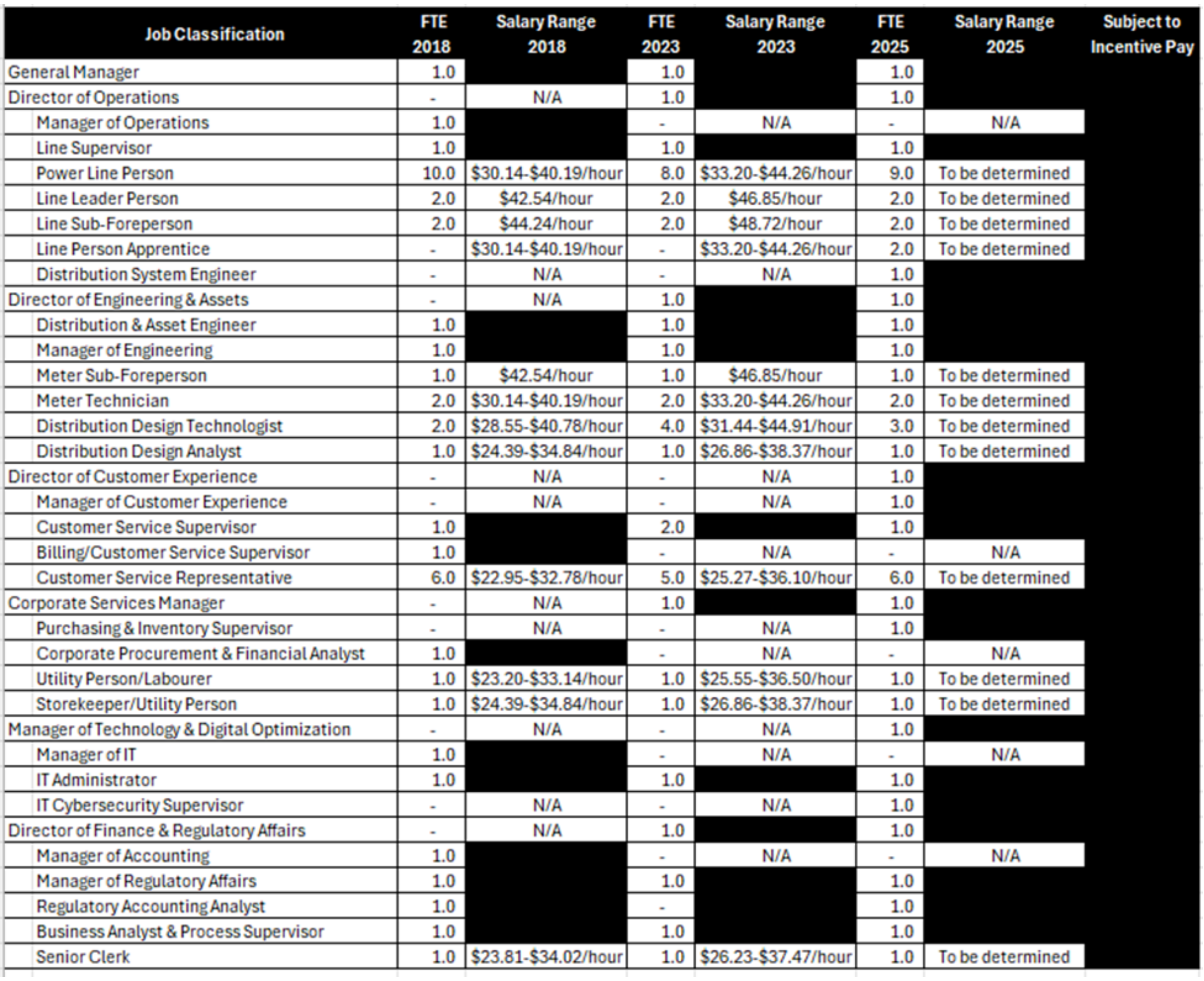
Reference: Exhibit 4, pages 52-

a) Please provide a table showing: (i) all job position/classifications, (ii) number of FTEs (headcount) in that position and, (iii) position salary range for the years 2018, 2023 and 2025. Please specify if the position numbers are on a year end-or year average basis. For each job classification please also indicate if the position is subject to incentive pay.

EPLC's Response:

Please see table below showing job positions and classifications.

Table 4-10: Job Positions and Classifications



Job Classification	FTE 2018	Salary Range 2018	FTE 2023	Salary Range 2023	FTE 2025	Salary Range 2025	Subject to Incentive Pay
General Manager	1.0	[redacted]	1.0	[redacted]	1.0	[redacted]	[redacted]
Director of Operations	-	N/A	1.0	[redacted]	1.0	[redacted]	[redacted]
Manager of Operations	1.0	[redacted]	-	N/A	-	N/A	[redacted]
Line Supervisor	1.0	[redacted]	1.0	[redacted]	1.0	[redacted]	[redacted]
Power Line Person	10.0	$30.14-$40.19/hour	8.0	$33.20-$44.26/hour	9.0	To be determined	[redacted]
Line Leader Person	2.0	$42.54/hour	2.0	$46.85/hour	2.0	To be determined	[redacted]
Line Sub-Foreperson	2.0	$44.24/hour	2.0	$48.72/hour	2.0	To be determined	[redacted]
Line Person Apprentice	-	$30.14-$40.19/hour	-	$33.20-$44.26/hour	2.0	To be determined	[redacted]
Distribution System Engineer	-	N/A	-	N/A	1.0	[redacted]	[redacted]
Director of Engineering & Assets	-	N/A	1.0	[redacted]	1.0	[redacted]	[redacted]
Distribution & Asset Engineer	1.0	[redacted]	1.0	[redacted]	1.0	[redacted]	[redacted]
Manager of Engineering	1.0	[redacted]	1.0	[redacted]	1.0	[redacted]	[redacted]
Meter Sub-Foreperson	1.0	$42.54/hour	1.0	$46.85/hour	1.0	To be determined	[redacted]
Meter Technician	2.0	$30.14-$40.19/hour	2.0	$33.20-$44.26/hour	2.0	To be determined	[redacted]
Distribution Design Technologist	2.0	$28.55-$40.78/hour	4.0	$31.44-$44.91/hour	3.0	To be determined	[redacted]
Distribution Design Analyst	1.0	$24.39-$34.84/hour	1.0	$26.86-$38.37/hour	1.0	To be determined	[redacted]
Director of Customer Experience	-	N/A	-	N/A	1.0	[redacted]	[redacted]
Manager of Customer Experience	-	N/A	-	N/A	1.0	[redacted]	[redacted]
Customer Service Supervisor	1.0	[redacted]	2.0	[redacted]	1.0	[redacted]	[redacted]
Billing/Customer Service Supervisor	1.0	[redacted]	-	N/A	-	N/A	[redacted]
Customer Service Representative	6.0	$22.95-$32.78/hour	5.0	$25.27-$36.10/hour	6.0	To be determined	[redacted]
Corporate Services Manager	-	N/A	1.0	[redacted]	1.0	[redacted]	[redacted]
Purchasing & Inventory Supervisor	-	N/A	-	N/A	1.0	[redacted]	[redacted]
Corporate Procurement & Financial Analyst	1.0	[redacted]	-	N/A	-	N/A	[redacted]
Utility Person/Labourer	1.0	$23.20-$33.14/hour	1.0	$25.55-$36.50/hour	1.0	To be determined	[redacted]
Storekeeper/Utility Person	1.0	$24.39-$34.84/hour	1.0	$26.86-$38.37/hour	1.0	To be determined	[redacted]
Manager of Technology & Digital Optimization	-	N/A	-	N/A	1.0	[redacted]	[redacted]
Manager of IT	1.0	[redacted]	-	N/A	-	N/A	[redacted]
IT Administrator	1.0	[redacted]	1.0	[redacted]	1.0	[redacted]	[redacted]
IT Cybersecurity Supervisor	-	N/A	-	N/A	1.0	[redacted]	[redacted]
Director of Finance & Regulatory Affairs	-	N/A	1.0	[redacted]	1.0	[redacted]	[redacted]
Manager of Accounting	1.0	[redacted]	-	N/A	-	N/A	[redacted]
Manager of Regulatory Affairs	1.0	[redacted]	1.0	[redacted]	1.0	[redacted]	[redacted]
Regulatory Accounting Analyst	1.0	[redacted]	-	[redacted]	1.0	[redacted]	[redacted]
Business Analyst & Process Supervisor	1.0	[redacted]	1.0	[redacted]	1.0	[redacted]	[redacted]
Senior Clerk	1.0	$23.81-$34.02/hour	1.0	$26.23-$37.47/hour	1.0	To be determined	[redacted]

4-VECC-37

Reference: Exhibit 4, page 25

a) The increase in the category are “General Customer Inquiries & Miscellaneous” is almost 20% as between 2024 and 2025. Why?
b) Are the AI assistant on EPLC’s website and the automated call answering program annual costs? In what year did these costs begin to be incurred.

EPLC’s Response:

a) EPLC confirms the difference of $53,378 between the 2024 Bridge year & 2025 Test year for General Customer Inquiries & Miscellaneous. The increase is the result of building assessment expenses anticipated to occur in 2025.
b) Yes, the AI Assistant & the automated call answering are both annual costs. These costs began to occur for EPLC in 2022.

4-VECC-38

Reference: **Exhibit 4, page 27**

a) AMI 2.0 is expected to result in any net savings in meter operations. Please provide an outline the expected future savings areas and the forecast amount of those savings.

EPLC's Response:

a) The intent of the AMI 2.0 Trials and Pilots in 2024-2025 is to work with vendors and test products to better understand the capabilities of a next generation meter asset base and better understand or quantify expected Capital & O&M savings. EPLC expects to achieve savings in the following areas:

New Features/Capabilities - The AMI 2.0 Trials and Pilot is intended to allow EPLC to learn what AMI 2.0 will offer, determine suitable specification for their use case, and forecast costs and savings. Learning about operational efficiencies, meter functionalities, hardware reliability, grid optimization, asset management, remote functionalities (ON/OFF), DER enablement, etc. will help EPLC identify and quantify potential newfound efficiencies and savings.

Failed Meter Replacements - It is assumed that a replacement of EPLC's aging meters with new meters will materialize in a reduction in O&M costs associated with replacing failing meter assets. EPLC has experienced an increase in the annual failure rate of existing meter assets. The AMI 2.0 Trials and Pilots will also help forecast O&M costs related to maintenance of a new meter base with the expectation that the costs will be less than EPLC's ageing metering infrastructure as supported by historical trends on the current meter base performance. Based on historical data, EPLC expects less new meters to fail through AMI 2.0 compared to their current rate of meter failures with their current meter base which will mostly reach its end of useful life prior to 2029.

Manual Data Reads – The expectation of AMI 2.0 is that there will be reduction in data gaps, communication issues, and therefore less need to spend on manual meter reads, re-billing, VEE, and estimation of meter data.

Meter Reverification – EPLC's current meter base is mostly approaching their 2nd round of meter re-sealing and the extension term is decreasing as per the Measurement Canada regulation (S-S-06—Sampling plans for the inspection of isolated lots of meters in service). As the seal extension terms continue to decrease, the costs to execute the meter reverification increases. Investment in AMI 2.0 will decrease the costs associated with conducting the meter reverification process for EPLC's total meter base since the new meters will have valid seals for a greater term.

DER Enablement – EPLC will assess the functionalities available in AMI 2.0 including the function of enabling DERs with standardized bi-directional meters. Based on assessment result, EPLC may opt to include this functionality in the AMI 2.0-meter base and forecast savings related to the enablement of DER's within their distribution service territory.

Mesh Network Maintenance – replacing EPLC's existing mesh network with a 100% coverage model to be able to read all meters with the proposed installation is expected to result in savings as the cost to maintain a new communication platform (cellular or mesh) is projected to be less than maintaining the existing, aging system.

Disconnects/Reconnects – New meter features and capabilities are expected to support savings in expenditures. For example, acquiring the functionality in the next generation meter base to remotely turn meters ON or OFF disconnect/reconnect process for maintenance, repairs, non-payment, etc.

Currently, EPLC has not projected Capital Savings. To date, EPLC has projected O&M savings for years 2027-2029. The forecast of 2027-2029 Projected O&M Savings is detailed below and in Section 2-Staff-25, a).

No immediate savings are realized in 2027 as EPLC begins to implement AMI 2.0, the existing AMI 1.0 asset base will be maintained and incur normal expected O&M costs.

In 2028, EPLC anticipates an estimated reduction in O&M costs of approximately $380,000 as the implementation of an AMI 2.0-meter base continues. The O&M costs for maintaining the AMI 1.0 asset base will continue at a reduced rate since the gross total assets decreases with the continued implementation of AMI 2.0.

In 2029, EPLC anticipates a continued reduction in O&M costs of an additional $100,000 as the implementation of an AMI 2.0-meter base continues. The O&M costs for maintaining the AMI 1.0 asset base will continue at a reduced rate until the AMI 2.0 project if fully executed.

4-VECC-39

Reference: **Exhibit 4, page 38**

a) Please provide the detailed Building Expense Budget for 2025.
b) Does EPLC have plans to review its building needs, location or anticipate any other activity during the rate period which might result in moving to a new or different building(s).

EPLC's Response:

a) 2025 budget $795,008

Table 4-11: Building Expense Budget 2025

Building Expense Budget 2025	
Description	Total
Misc General Expenses	$ 69,720
Misc Gen Assoc Dues	$ 115,986
Maint of Plant-Lab	$ 72,315
Maint of Plant-Exp	$ 183,855
Comp HW Mtc	$ 18,732
Comp SW Mtc	$ 320,000
ESA Fees	$ 14,400
Total	$ 795,008

b) EPLC does not anticipate a need to move into a new or different building(s) during the rate period.

4-VECC-40

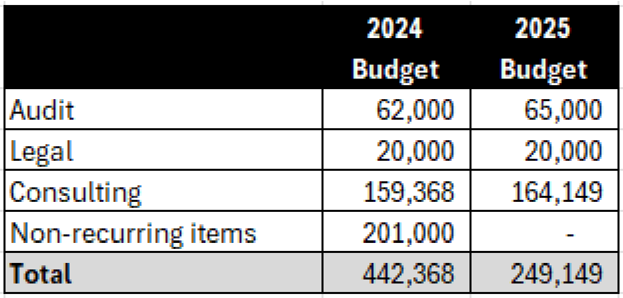
Reference: Exhibit 4, page 39, 4.3.5.3 – Program Costs

a) Please provide the detailed budget for legal audit and consulting showing the breakdown in estimated costs in those three categories.

EPLC's Response:

a) The detailed budget breakdown for the 2024 bridge year and 2025 test year is as follows:

Table 4-12: Detailed Budget Breakdown for 2024 Bridge and 2025 Test Year



	2024 Budget	2025 Budget
Audit	62,000	65,000
Legal	20,000	20,000
Consulting	159,368	164,149
Non-recurring items	201,000	-
Total	442,368	249,149

The non-recurring items in the 2024 budget anticipate the legal costs related to collective agreement negotiations and additional legal costs related to specific initiatives that are foreseen to occur.

4-VECC-41

Reference: **Exhibit 4, pages 20, 40**

“EPLC’s previous Application (EB-2017-0039), was settled well into that rate year and during that settlement process, the one-time costs associated with the preparation of that application, and which were approved to be included in OM&A over the 5-year rebasing period, were actually expensed in 2018.”

“Certain one-time costs that were included in the previous 16 Application and planned to be recovered using the 1/5 methodology were expensed in 2018”. (emphasis added)

a) What was the amount of the one-time regulatory costs expensed in 2018.
b) Was the total amount expensed and included in the $519,964 reported in Appendix 2-JC?

EPLC’s Response:

a) The total amount of the one-time regulatory costs expensed in 2018 are $109,819. This total is broken down in the table below.

Table 4-13: One Time Regulatory Cost Breakdown for 2018

Description	Amount
Regulatory Expenses-Legal	$35,061
Regulatory Expenses - Labour	$17,910
Regulatory Expenses- Other	$56,848
Total	$109,819

b) Yes, all one-time regulatory charges were included and expensed within the $519,694 reported in Appendix 2-JC. Please see the breakdown of this total below.

Table 4-14: Breakdown of One-Time Regulatory Charges

Account Description	2018 Account Balance
Regulatory Expenses-Legal	$35,061
Regulatory Expenses - Labour	$225,067
Regulatory Expenses- Other	$62,255
Regulatory Expenses (formal case costs & OEB fees)	$197,580
Total	$519,964

4-VECC-42

Reference: **Exhibit 4, pages 39, 4.3.5.3 4.7**

Appendix 2-M

Regulatory Cost Category		USoA Account
(A)		(B)
Regulatory Costs (Ongoing)		
1	OEB Annual Assessment	5655
2	OEB Section 30 Costs (OEB-initiated)	5655
3	Expert Witness costs for regulatory matters	
4	Legal costs for regulatory matters	
5	Consultants' costs for regulatory matters	5630
6	Operating expenses associated with staff resources allocated to regulatory matters	5615
7	Operating expenses associated with other resources allocated to regulatory matters [1]	5655
8	Other regulatory agency fees or assessments	5655
9	Any other costs for regulatory matters (please define)	5610
10	Intervenor costs	5655

a) EPLC appears to have created Appendix 2-M with only one-time application costs. Above is shown a typical Appendix 2-M by category filing. Please fill out this table including the following columns:
   i. Last Rebasing (year)
   ii. Sum of Historical Years (date-to-date)
   iii. 2024 Bridge Year
   iv. 2025 Test Year.

   There also does not appear to be any 2025 cost recorded in the Appendix (showing among other things the forecast 2025 OEB Assessment Costs)

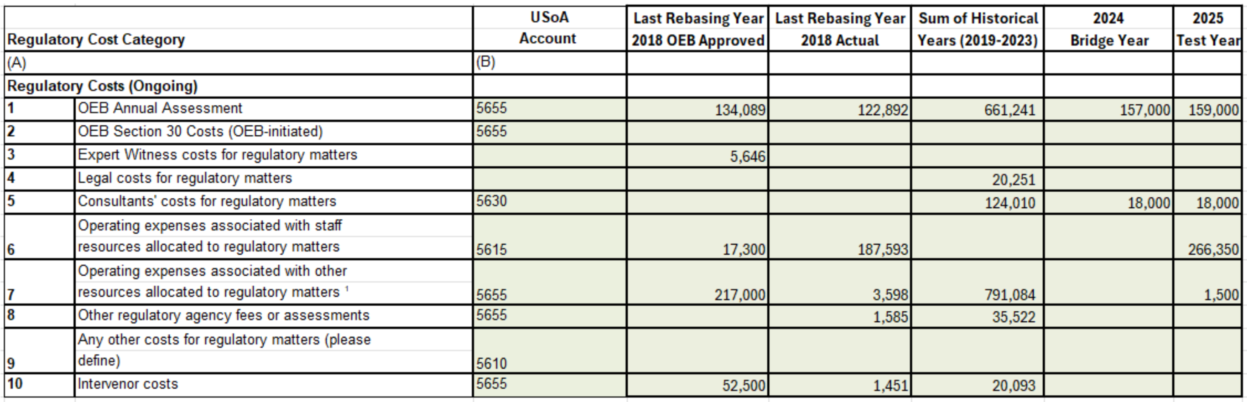
b) Please provide update Table 4-30 to show the costs incurred to date.

c) Please clarify what the nature of the “incremental operating expenses associated with other resources allocated to this application” of $166,718.

EPLC’s Response:

a) Appendix 2-M has been revised to include:
    i. Last Rebasing (year)
    ii. Sum of Historical Years (2019-2023)
    iii. 2024 Bridge Year
    iv. 2025 Test Year

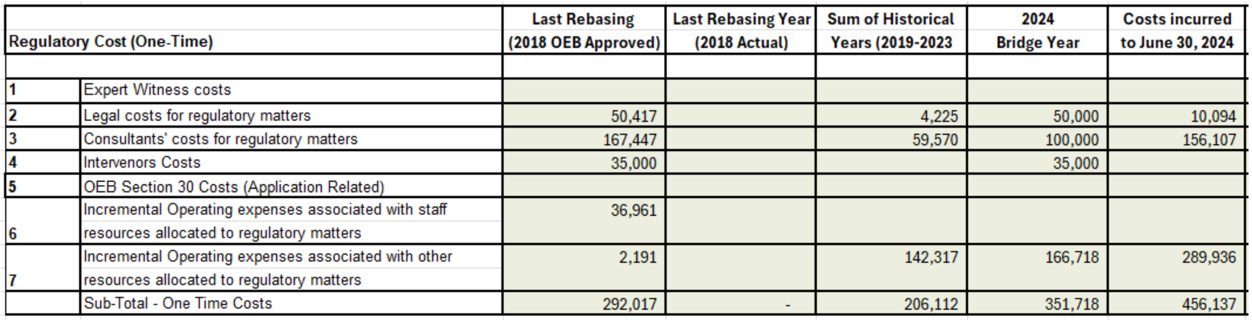
Table 4-15: Revised Appendix 2-M



	Regulatory Cost Category	USoA Account	Last Rebasing Year 2018 OEB Approved	Last Rebasing Year 2018 Actual	Sum of Historical Years (2019-2023)	2024 Bridge Year	2025 Test Year
(A)		(B)					
Regulatory Costs (Ongoing)							
1	OEB Annual Assessment	5655	134,089	122,892	661,241	157,000	159,000
2	OEB Section 30 Costs (OEB-initiated)	5655					
3	Expert Witness costs for regulatory matters		5,646				
4	Legal costs for regulatory matters				20,251		
5	Consultants' costs for regulatory matters	5630			124,010	18,000	18,000
6	Operating expenses associated with staff resources allocated to regulatory matters	5615	17,300	187,593			266,350
7	Operating expenses associated with other resources allocated to regulatory matters[1]	5655	217,000	3,598	791,084		1,500
8	Other regulatory agency fees or assessments	5655		1,585	35,522		
9	Any other costs for regulatory matters (please define)	5610					
10	Intervenor costs	5655	52,500	1,451	20,093		

b) Table 4-30 has been updated to show all actual one-time costs incurred up to June 30, 2024.

Table 4-16: Revised Table 4-30 in Exhibit 4



	Regulatory Cost (One-Time)	Last Rebasing (2018 OEB Approved)	Last Rebasing Year (2018 Actual)	Sum of Historical Years (2019-2023	2024 Bridge Year	Costs incurred to June 30, 2024
1	Expert Witness costs					
2	Legal costs for regulatory matters	50,417		4,225	50,000	10,094
3	Consultants' costs for regulatory matters	167,447		59,570	100,000	156,107
4	Intervenors Costs	35,000			35,000	
5	OEB Section 30 Costs (Application Related)					
6	Incremental Operating expenses associated with staff resources allocated to regulatory matters	36,961				
7	Incremental Operating expenses associated with other resources allocated to regulatory matters	2,191		142,317	166,718	289,936
	Sub-Total - One Time Costs	292,017	-	206,112	351,718	456,137

c) The incremental operating expenses reflects the support provided by EPC in the preparation of this application.

4-VECC-43

Reference: Exhibit 4, page, 52, 2.4.3.3

a) Please provide a list of all utility memberships (e.g. EDA, CHEC Group, USF etc.) and the associated annual membership fees for the years 2018 through 2025 (forecast).

EPLC's Response:

Please see the table below for a list of all utility memberships for the years 2018 (Actuals) - 2025 (Forecast).

Table 4-17: Utility Memberships

Memberships	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast
OEB Annual Registration Fee	$800	$800	$800	$800	$800	$800	$800	$800
EDA	$49,800	$50,800	$56,800	$62,300	$67,300	$71,400	$73,200	$78,100
USF	$8,750	$8,750	$7,950	$8,750	$8,750	$9,000	$9,405	$9,500
GridSmartCity	$14,000	$15,000	$15,000	$20,000	$30,000	$30,000	$29,000	$33,200
Electric Safety Authority Fees	$12,731	$12,761	$13,136	$13,088	$13,402	$13,528	$15,655	$16,225
Total	$86,081	$88,111	$93,686	$104,938	$120,252	$124,728	$128,060	$137,825

4-VECC-44

Reference: Exhibit 4, page 48

"EPLC calculated the FTE totals in Table 4-15 above by pro-rating new employees based on their starting 10 month in a given year, pro-rating departing employees based on their last month of work. EPLC included 11 co-op students and contract employees in this analysis. New positions budgeted for 2025 are planned to 12 commence January 1 of that year and costs above reflect a full year of costs for any new positions. EPLC 13 plans to begin the recruiting process at the start of the fourth quarter of 2024 to achieve that timing"

a) Please provide current number of full time and (separately) part-time employees (i.e. employees not FTEs).
b) Please provide the number of the full time and part-time employees forecast to be employed at the end of 2024 and (separately) at the end of 2025.detailed Building Expense Budget for 2025.

EPLC's Response:

a) EPLC currently has 41 full-time and no part-time employees.
b) EPLC forecasts 47 full-time and no part-time employees at the end of 2024 and 51 full-time and no part-time employees at the end of 2025.

   It is assumed that the last few words in section b) "detailed Building Expense Budget for 2025" is a typographical error and has therefore not been addressed in EPLC's response.

4-VECC-45

Reference: **Exhibit 4, pages 50-**

a) Please provide the current status of the hiring of the Director of Customer Experience, IT Cybersecurity Analyst, Distribution System Engineer and Purchasing Manager.
b) Please provide the job description and salary ranges for these new positions.
c) Are all of these all management positions eligible for incentive payments?

EPLC's Response:

a) The Director of Customer Experience job description is still in progress. The Distribution System Engineer position will be posted in 2025. The IT Cybersecurity Analyst title was changed to Cybersecurity Supervisor, has a draft job description and is anticipated to be a 2024 hire. The Purchasing Manager title was changed to Purchasing and Inventory Supervisor. The job has been posted and the posting has been closed. EPLC anticipates conducting interviews for that position in the coming weeks.
b) Please see response to 4.0-VECC-36 for the salary ranges for these positions. Please see Attachment D for job descriptions.
c) Please see response to 4.0-VECC-36.

4-VECC-46

Reference: **Exhibit 4, page 38**

a) Please provide the detailed Building Expense Budget for 2025.
b) Does EPLC have plans to review its building needs, location or anticipate any other activity during the rate period which might result in moving to a new or different building(s).

EPLC's Response:

Please see response to 4-VECC-39.

4-VECC-47

Reference: **Exhibit 4, page 58**

a) Why has the charge for water billing & collection to the municipalities of Tecumseh and Amherstburg not changed since 2023 (and only slightly from 2022) whereas the related billing and collection costs of EPLC have increased significantly during that same period?

EPLC Response:

a) EPLC's billing and collection costs encompass all customers, electricity and water/sewer. Investments that leverage automation have been implemented, which provide more impactful benefits to electricity customers due simply to their larger number.

Exhibit 5- Cost of Capital

OEB Staff Interrogatories

5-Staff-52

Return on Equity
Ref 1: Exhibit 5, 5.2.7 Historical ROE, page 6

Preamble:

Essex Powerlines' achieved Return on Equity (ROE) in 2023 is 4.50% and deemed ROE is 9%. OEB staff notes that achieved ROE is 300 basis points below the deemed.

Question(s):

a. Please explain the reason for the achieved ROE being 300 basis points below deemed in 2023.

EPLC's Response:

EPLC's 2023 ROE was 300 basis points below deemed ROE of 9% primarily due to increased amortization as a result of capital spending higher than anticipated per the 2018 Board decision (EB-2017-0039).

5-Staff-53

Cost of Capital
Ref 1: EB-2024-0063, Notice, March 6, 2024
Ref 2: EB-2024-0063, OEB Letter, April 22, 2024

Preamble:

On March 6, 2024, the OEB commenced a hearing (EB-2024-0063) on its own motion to consider the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and Ontario Power Generation Inc. The methodology for determining the OEB's prescribed interest rates and matters related to the OEB's Cloud Computing Deferral Account will also be considered, including what type of interest rate, if any, should apply to this deferral account.

On April 22, 2024, the OEB approved the final Issues List for this proceeding, including the following two issues, amongst other issues:

> 18. How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?
>
> 19. Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle ofn approved rate term, and if so, how?

Question(s):

a) Please confirm that the applicant proposes to implement the outcomes from the OEB's generic cost of capital proceeding, including what the OEB decides with respect to implementation. If this is not the case, please explain.

EPLC's Response:

EPLC intends to comply with the provisions from the OEB's cost of capital proceeding; however, with the proceeding still in process, such outcomes and their resulting ramifications, are unknown.

School Energy Coalition (SEC)

5-SEC-36

[Ex. 5, Appendix 2-OB] Please redo Appendix 2-OB making the following changes:

a. For Column I expand to show four decimal places.
b. For Column J use Column H x Column I instead of prepopulating or explain why Essex has not done it this way.

EPLC's Response:

EPLC has updated Appendix 2-OB and made both changes as noted above.

Vulnerable Energy Consumers Coalition (VECC)

5-VECC-48

Reference: Exhibit 5,

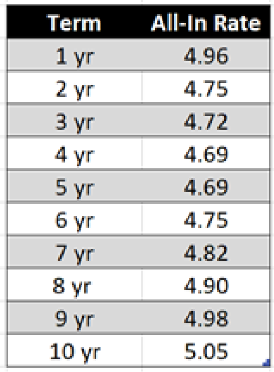
"The noted interest rate on this new debt instrument is forecast at 4.88%, based on a quote received March 25, 2024, from EPLC primary lender, TD Bank."

a) Please provide the most recent forecast for the cost of debt to be secured at the end of 2024.
b) Why is EPLC waiting until December 1, 2024 to secure this loan?

EPLC's Response:

a) EPLC has requested and received a more recent forecast of the cost of debt planned to be secured at the end of 2024; those rates are shown below.

Table 5-1: Planned Cost of Debt Rates



Term	All-In Rate
1 yr	4.96
2 yr	4.75
3 yr	4.72
4 yr	4.69
5 yr	4.69
6 yr	4.75
7 yr	4.82
8 yr	4.90
9 yr	4.98
10 yr	5.05

b) EPLC is waiting until December of 2024 to secure the loan in hopes of securing a slightly better interest rate.

5-VECC-49

Reference: **Exhibit 5, Appendix 2OB, Attachment 5C**

a) Please amend the tables in Appendix 2-OB to show the rate to four decimal points

EPLC's Response:

EPLC has updated Appendix 2-OB to show the rate to four decimal points.

5-VECC-50

Reference: **Exhibit 5,**

a) In 2025 ELPC's actual long-term debt will be underleveraged in comparison to its approved structure for the purpose of rate making ($38,682,209 vs $46,736,652). Please discuss ELPC's financing strategy and why it was a prudent fiscal strategy to not borrow during prior periods when interest costs were lower.

EPLC's Response:

a) EPLC has corrected Appendix 2-OB to reflect the opening principal balance of debt instruments, resulting in actual planned long-term debt of $40,806,615. EPLC assesses borrowing requirements and plans financing as part of the annual budget process and for one year did not add new debt. However, this was immediately following a year in which EPLC borrowed 2 tranches of funding at favourable rates of 2.000% and 2.0790%. As rates have remained high, in recent years EPLC has decided to secure shorter borrowing terms to permit the opportunity to obtain slightly lower rates sooner as rates begin to cool.

Exhibit 6- Revenue Requirement and Revenue Deficiency or Sufficiency

OEB Staff Interrogatories

6-Staff-54

Tax Return
Ref: Exhibit 6, page 8

Preamble:

Essex Powerlines states that:

"EPLC has not filed its 2023 Corporate Income Tax Return with the Canada Revenue Agency (CRA); as a result, the information included in the 2023 Historical year in the Income/Tax/PILs model could potentially change. Once EPLC has filed its 2023 statutory corporate income tax return with the CRA, then EPLC will use the information from its T2 return to update the 2023 projection, and it will make any updates to the 2024 Bridge Year and the 2025 Test Year Income Tax/PILs model as required and incorporate those changes in an update to the rate application during the Interrogatory phase should that prove necessary."

Question(s):

a) Please provide the 2023 T2 return if available and update the relevant evidence as necessary.

EPLC's Response:

EPLC's 2023 T2 return is attached as Attachment E. The Income/Tax PILs model has been updated with all necessary changes.

6-Staff-55

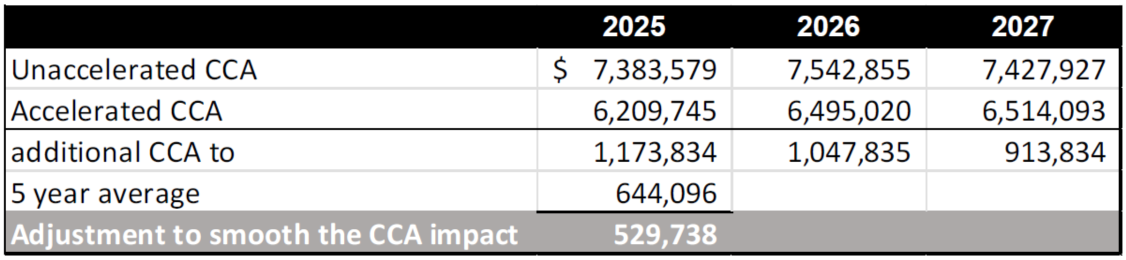
PILS
Ref 1: Exhibit 6, pages 9-10
Ref 2: Essex Powerlines' PILs model
Ref 3: Letter – Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance (oeb.ca)

Preamble:

Essex Powerlines has estimated the impact the accelerated program will have on PILs throughout the planned cost of service cycle from 2025–2029 and derived the adjustment to smooth the impact of CCA in the 2025 Test Year, as summarized in Tables 6-7.

OEB staff notes that Essex Powerlines adjusted its 2025 PILs upward by $529,738 which is derived from the table below.

Table 6-7: CCA Smoothing Adjustment



	2025	2026	2027
Unaccelerated CCA	$ 7,383,579	7,542,855	7,427,927
Accelerated CCA	6,209,745	6,495,020	6,514,093
additional CCA to	1,173,834	1,047,835	913,834
5 year average	644,096		
Adjustment to smooth the CCA impact	**529,738**		

OEB staff notes that the CCA calculated in 2025 PILs model (Tab 8 Sch 8 CCA Test) is

$7,124,792 using the OEB's PILs model which is based on the phased-out effect of the CCA for 2025. This amount does not equal to any of the amounts for 2025 in the table above.

The OEB issued a letter in 2019 while establishing the sub-account CCA changes under Account 1592. The letter states that:

Under the Accounting Procedures Handbook, electricity distributors and transmitters are to record the impact of any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the OEB Tax Model that is used to determine the tax amount that underpins rates.

The letter also states that:

The OEB expects Utilities, including those whose applications are currently before the OEB, to reflect any impacts arising from CCA rule changes in their cost-based applications for 2020 rates and beyond. The OEB recognizes that there may be timing differences that could lead to volatility in tax deductions over the rate-setting term. The OEB may consider a smoothing mechanism to address this.

OEB staff compiles a table summarizing the differences in the CCA tax rules that are embedded in rates and the CCA tax rules to be applied by utilities for the rate term of 2025 to 2029:

OEB staff Table 1: CCA Tax Rules Differences for the Rate Term 2025 - 2029

	2025	2026	2027	2028	2029
CCA Tax rules embedded in rates	Accelerated CCA (Twice of the legacy rule for the additions)				

Actual CCA tax rules to be applied by Utilities in Tax filings	Accelerated CCA (Twice of the legacy rule for the additions) Accelerated CCA	Legacy half- year rule	Legacy half- year rule

Question(s):

a) Please explain the following for Table 6-7:
    i. How does Essex Powerlines calculate the numbers in the row of "Unaccelerated CCA" for 2025 to 2027?
    ii. How does Essex Powerlines calculate the numbers in the row of "Accelerated CCA" for 2025 to 2027?
    iii. Why the numbers in the row of "Accelerated CCA" are less than the numbers in the row of "Unaccelerated CCA"?
    iv. Please explain how the five-year average of $644,096 is calculated.

b) Please confirm that Essex Powerlines has reflected the AIIP rule in the test year's CCA calculation in the PILs model. Please update the evidence and PILs model if not confirmed.

c) Based on the OEB staff Table 1 above, please confirm that there will be no differences with respect to the CCA tax rules between the CCAs that is embedded in rates and the actual CCAs to be claimed by Essex for the years of 2025 to 2027 and the tax rule differences are in the years of 2028 and 2029.

d) Based on the OEB staff Table 1 above, please confirm that the tax rule differences in 2028 and 2029 would result in a collection from customers because Essex Powerlines would deduct less CCAs using the legacy half-year rule in 2028 and 2029's tax filings as compared to the accelerated CCA rule that is embedded in the rates of this rate term.

e) Based on the above understanding, please recalculate the smoothing adjustment for the rate term of 2025 to 2029 showing no differences in the years of 2025 to 2027 and differences in 2028 and 2029. Please provide the detailed calculations for the CCAs which are used in deriving the adjustment.

f) Please also confirm that Essex Powerlines' proposal is to adjusting the Test Year's PILs by smoothing the PILs impact in its rate term and discontinue the use of Account 1592 sub-account CCA changes.

EPLC's Response:

a) EPLC has revised Table 6-7 as follows:

Table 6-1: Revised Table 6-7 in Exhibit 6 (CCA Smoothing Adjustment)

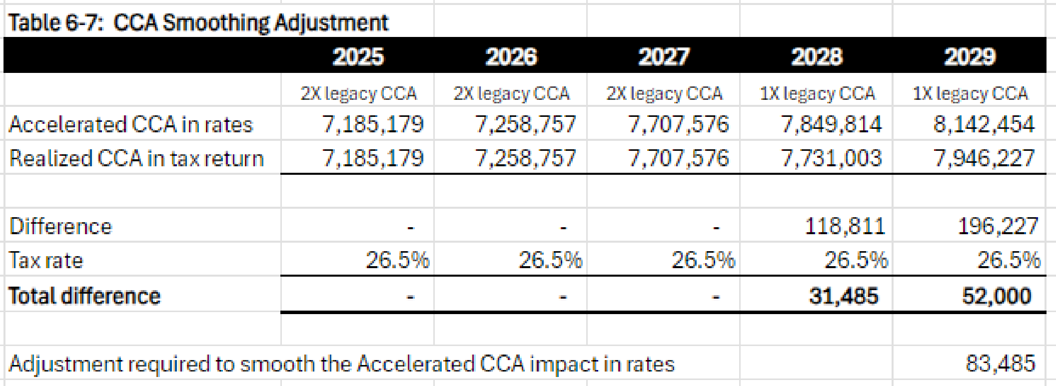


Table 6-7: CCA Smoothing Adjustment

	2025	2026	2027	2028	2029
	2X legacy CCA	2X legacy CCA	2X legacy CCA	1X legacy CCA	1X legacy CCA
Accelerated CCA in rates	7,185,179	7,258,757	7,707,576	7,849,814	8,142,454
Realized CCA in tax return	7,185,179	7,258,757	7,707,576	7,731,003	7,946,227
Difference	-	-	-	118,811	196,227
Tax rate	26.5%	26.5%	26.5%	26.5%	26.5%
Total difference	**-**	**-**	**-**	**31,485**	**52,000**
Adjustment required to smooth the Accelerated CCA impact in rates					83,485

i. Because Accelerated CCA will be embedded in EPLC's rate term of 2025 to 2029 (per the OEB Staff Table 1 above), adjustments will not be required to reflect a difference between CCA calculated at the accelerated rate and CCA calculated at the legacy rate for the years 2025 through 2027. In these three years, EPLC will file its tax return using the Accelerated CCA tax rule of twice the legacy rule for the additions. For 2028 and 2029, EPLC will file its tax return using the legacy half-year rule, which will result in differences. This is reflected as "Realized CCA in tax return" in the table above.

ii. EPLC has flowed the forecast capital additions for 2025 to 2029 through Schedule 8 of a mock tax return using the Accelerated CCA tax rule of twice the legacy rule for additions. This is reflected as "Accelerated CCA in rates" in the table above.

iii. In the initial Table 6-7 filed, the rows were incorrectly labelled. These rows are no longer applicable in the table above.

iv. The five-year average is no longer applicable in the table above.

b) EPLC confirms that it has reflected the AIIP rule in the test year's CCA calculation in the PILs model.

c) EPLC confirms that there will be no tax differences with respect to the CCA tax rules for the years 2025 through 2027, as the Accelerated CCA tax considerations will be embedded in EPLC's rates commencing in 2025. EPLC also confirms that there will be tax differences in 2028 and 2029 as the Accelerated CCA rules are phased out commencing in 2028.

d) EPLC confirms that the tax rule differences in 2028 and 2029 would result in a collection from customers because EPLC would deduct less CCA using the legacy half-year rule in those years as compared to the Accelerated CCA rule that will be embedded in rates.

e) The revised table above calculates the smoothing adjustment for the rate term 2025 to 2029. Detailed calculations are provided in Attachment F. The smoothing mechanism negates the requirement for collection from customers as outlined in part d) above.

f) EPLC confirms that it has adjusted the Test Year's PILs by smoothing the PILs impact in its rate term and will discontinue the use of Account 1592 sub-account CCA changes.

School Energy Coalition (SEC)

6-SEC-37

[Ex. 6, Appendices 2-H and 2-N] With respect to accounts 4375 and 4380, please explain the following, for 2025:

a. Appendix 2-H Account 4375 shows revenues of $127,594 and Appendix 2-N shows $142,539 for streetlight services.
b. In Appendix 2-H Work for others revenue is less than Work for others expenses.

EPLC's Response:

a. Appendix 2-H should show revenues of $142,539 for Account 4375, which agrees to Appendix 2-N. Appendix 2-H has been amended to reflect this correction.
b. Appendix 2-H has been amended to reflect Work for Others revenue of $34,945 and Work for Others expenses of $31,800.

6-SEC-38

[Ex. 6, p.13, Appendix 2-H] Essex has included in Other Revenue Accounts 4375 and 4380 the following for the Zero Emission Vehicle Infrastructure Program:

USoA	USoA Description	Essex's description	2022	2023
4375	Revenues from Non Rate-Regulated Utility Operations	Zero Emission Vehicle Infrastructure Program expenses	-$71,780	-$1,305,329
4380	Expenses of Non Rate-Regulated Utility Operations	Zero Emission Vehicle Infrastructure Program revenues	$86,562	$1,316,299

a. Please confirm that the numbers provided in 4375 are revenues and the numbers provided in 4380 are expenses.
b. Please provide details on what work is included in the expenses for this program, including:
    i. Is it only OM&A?
    ii. Who performed the work, i.e., Essex employees, affiliate employees, contractors?
    iii. If the answer to ii. is Essex employees, please provide the number of employees and what their positions were/are when they are working on this initiative.

EPLC's Response:

a. EPLC confirms that the numbers provided in 4375 are revenues and the numbers provided in 4380 are expenses and were labelled incorrectly in Appendix 2-H.
b. The expenses of the program:
    i. All work was exclusively OM&A.
    ii. The work was performed by Essex employees and affiliate employees.
    iii. EPLC's General Manager spent some time on the development of the program contract and its execution. Three Finance employees (Manager/Supervisor/unionized

Clerk) devoted some time to the establishment of appropriate financial accounting processes associated with the program, invoicing of participants and follow-up and recording of payments throughout the life of the program.

Vulnerable Energy Consumers Coalition (VECC)

6-VECC-51

Reference: Chapter 2 Appendices, Appendix 2-H

a) Please explain why there is no forecast revenue for 2024 or 2025 for Accounts 4082 and 4084.

b) Please provide the basis for the 2024 and 2025 forecasts for the following Accounts:

  i. #4235
  ii. #4355
  iii. #4357
  iv. #4362
  v. #4375
  vi. #4380
  vii. #4390

c) Please provide the basis for the Joint Use Pole Attachments revenue for 2023, 2024 and 2025 (i.e. # of poles, rate per pole, etc.).

d) With respect to Account 4375 please explain the basis for the 2022 and 2023 revenues from the Zero Emission Infrastructure Program and why there are no revenues for 2024 or 2025.

EPLC's Response:

a) Revenues have not been forecast for 2024 and 2025 for accounts 4082 and 4084 due to their relative immateriality.

b) The basis for the 2024 and 2025 forecasts for the following accounts:

  i. Account 4235, Miscellaneous services revenues: the forecasts were based on historical results during the fiscal years 2018-2023, wherein the balances fluctuated between $135-$156k
  ii. Account 4355, Gain on disposition of utility and other property: the forecasts were based on historical results during the fiscal years 2018-2023, wherein balances fluctuated between $8-$57k
  iii. Account 4357, Gain from retirement of utility and other property: the forecasts were based on historical results during the fiscal years 2018-2023, wherein balances fluctuated between $12-$67k
  iv. Account 4362, Loss from retirement of utility and other property: the forecasts were based on historical results during the fiscal years 2018-2023, wherein balances fluctuated between $25-$94k

v. Account 4375, Revenues from non rate-regulated utility operations: the forecasts were built using best estimates of planned work for others, streetlight revenues and water billing and collecting revenues per contract with municipalities

vi. Account 4380, Expenses of non rate-regulated utility operations: the forecasts were built using best estimates of expenses associated with planned work for others, streetlight expenses and water billing and collecting expenses

vii. Account 4390, Miscellaneous non-operating income: the forecasts were based on historical results during the fiscal years 2018-2023, wherein balances fluctuated between $11-$38k, with the exception of fiscal years 2021 and 2023, which experienced one-time recognition of revenue

c) Account 4210, Joint Use Pole Attachments revenue incorrectly showed a balance of $265,220 on Appendix 2-H for 2023. The actual balance should be $166,169, which is made up of 7,230 telecommunication poles at the allowable rate of $22.35, 115 non-telecommunication poles at a rate of $36.05 and 24 clearance poles at the Joint Use Agreement rate of $18.03.
The 2024 and 2025 forecasts were based on historical results during the fiscal years 2018-2023, wherein balances fluctuated between $117-$161k.

d) The revenues in 2022 and 2023 from the Zero Emission Infrastructure Program were the actual revenues from the participants in the program. The program was deployed in 2022 and was expected to continue into 2024, but program funds were completely extinguished in 2023.

Exhibit 7- Cost Allocation

OEB Staff Interrogatories

7-Staff-56

Weighting Factors
Ref 1: Exhibit 7, Page 5

Preamble:

Explanations are provided to support the relative the approximate weighting factors but are not at a level of detail sufficient to determine the appropriate weightings.

Question(s):

a) Please provide a detailed derivation of the Billing and Collecting weighting factors used.
b) Please confirm that each sentinel light is billed as a separate customer.
c) Please advise if sentinel lights are billed separately from other services, or if they are included as a line item on separate bills, and how this is reflected in the weighting factor used.

EPLC's Response:

a) Please refer to response to 7-SEC-39 Part A.

b) Sentinel lights are billed as a separate line item on a customer's bill.

c) Sentinel lights are billed as a separate line item on a customer's bill; for weighting factors, Sentinel lights are considered a connection point and therefore receive weighting as if each was an individual customer.

7-Staff-57

Primary / Secondary Breakout
Ref 1: Exhibit 7, Page 7

Preamble:

Essex Powerlines indicates that assets were broken out into primary and secondary distribution functions using current information on the distribution system.

Question(s):

a) Please describe the methodology for breaking assets out into primary and secondary distribution functions. For example, if a project replaced a pole line with both primary and secondary conductors, please describe the methodology to track primary costs and secondary costs with respect to the poles, fixtures, conductors, and labour.

EPLC's Response:

a) Assets are broken out into Primary and Secondary functions based on network voltage and conductor size and type. Primary voltage within EPLC service territory is predominantly 27.6 kV for three phase circuits and 16 kV for single phase or branch circuits and utilizes various sizes of ASCR (Aluminum Conductor Steel Reinforced). For Secondary services, the voltage will vary from 120/240 V or 120/208 up to 347/600 V and utilizes various sizes of triplex or quad insulated aluminum and occasionally copper conductors. When replacing a pole line that carries both Primary and Secondary level infrastructure, it would be classified as the higher voltage, in the questioned example, as Primary. The reasoning for this is that in terms of poles, fixtures, conductor and labour, the typical costs associated with the Primary infrastructure far outweigh the cost of the secondary infrastructure.

7-Staff-58

Meter Reading
Ref 1: Cost Allocation Model, sheet I6.2 Customer Data, sheet I7.2 Meter Reading

Preamble:

The meter reading table includes 353,451 meter reading events for Residential. This is consistent with the 353,451 annual residential bills (29,454 customers * 12 bills per year each). The meter reading table indicates 2,098 meter reading events for GS < 50, 235 meter reading events for GS > 50, and 4 meter reading events for Large Use. These match the number of customers in each of those classes, not the number of annual bills.

Question(s):

a. Please revise the cost allocation model so that the meter reading tab consistently reflects either the number of customers, or the number of bills for all classes. If Essex Powerlines believes this is not appropriate, please explain why.

EPLC's Response:

a) EPLC has updated the Cost Allocation Model to correct the GS,50, GS>50 and Embedded Distributor class to reflect the number of customers times 12 on Tab 7.2 Meter Reading.

School Energy Coalition (SEC)

7-SEC-39

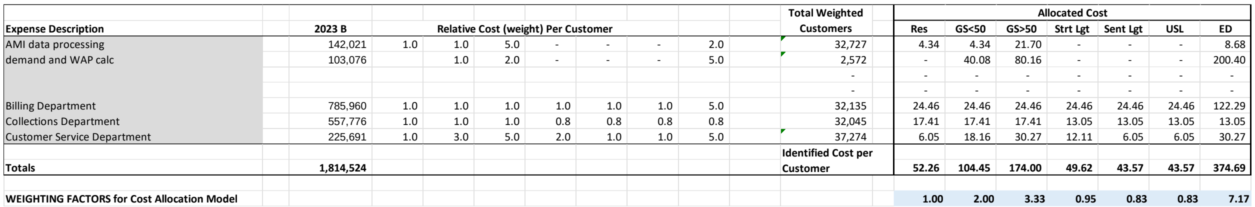
[Ex. 7, Tables 7-2 and 7-4 and Cost Allocation Model] Please provide the backup data and analysis that was used to calculate:

a. Weighting Factors for Billing and Collection in Table 7-2 and Tab I5.2 of the Cost Allocation Model.
b. Meter Reading Weighting Factor of 25 for Interval Meters in Table 7-4 and Tab I7.2 of the Cost Allocation Model.

EPLC's Response:

a)

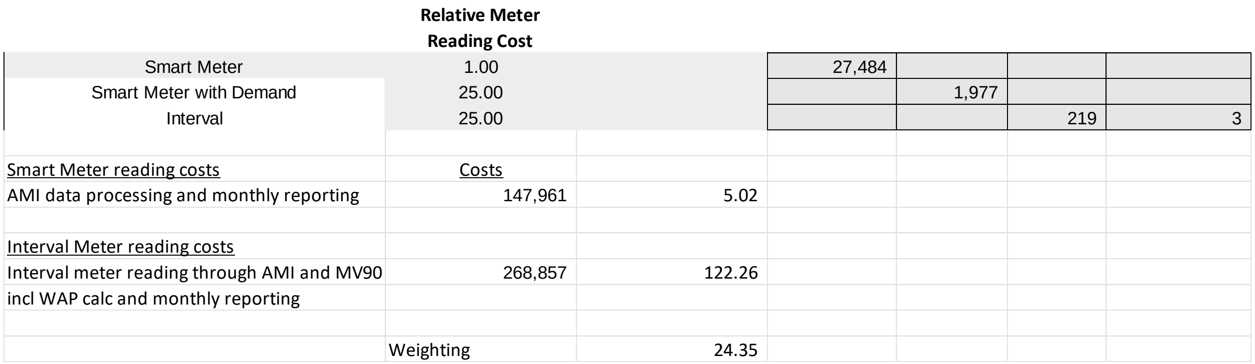
Table 7-1: Weighting Factors for Billing and Collection



									Total Weighted	Allocated Cost						
Expense Description	**2023 B**	**Relative Cost (weight) Per Customer**							**Customers**	**Res**	**GS<50**	**GS>50**	**Strt Lgt**	**Sent Lgt**	**USL**	**ED**
AMI data processing	142,021	1.0	1.0	5.0	-	-	-	2.0	32,727	4.34	4.34	21.70	-	-	-	8.68
demand and WAP calc	103,076		1.0	2.0	-	-	-	5.0	2,572	-	40.08	80.16	-	-	-	200.40
									-	-	-	-	-	-	-	-
									-	-	-	-	-	-	-	-
Billing Department	785,960	1.0	1.0	1.0	1.0	1.0	1.0	5.0	32,135	24.46	24.46	24.46	24.46	24.46	24.46	122.29
Collections Department	557,776	1.0	1.0	1.0	0.8	0.8	0.8	0.8	32,045	17.41	17.41	17.41	13.05	13.05	13.05	13.05
Customer Service Department	225,691	1.0	3.0	5.0	2.0	1.0	1.0	5.0	37,274	6.05	18.16	30.27	12.11	6.05	6.05	30.27
Totals	**1,814,524**								**Identified Cost per Customer**	**52.26**	**104.45**	**174.00**	**49.62**	**43.57**	**43.57**	**374.69**
WEIGHTING FACTORS for Cost Allocation Model										**1.00**	**2.00**	**3.33**	**0.95**	**0.83**	**0.83**	**7.17**

b)

Table 7-2: Meter Reading Weighting Factor for Interval Meters



	Relative Meter Reading Cost					
Smart Meter	1.00		27,484			
Smart Meter with Demand	25.00			1,977		
Interval	25.00				219	3
Smart Meter reading costs	Costs					
AMI data processing and monthly reporting	147,961	5.02				
Interval Meter reading costs						
Interval meter reading through AMI and MV90 incl WAP calc and monthly reporting	268,857	122.26				
	Weighting	24.35				

Vulnerable Energy Consumers Coalition (VECC)

7-VECC-52

Reference: Exhibit 7, page 5

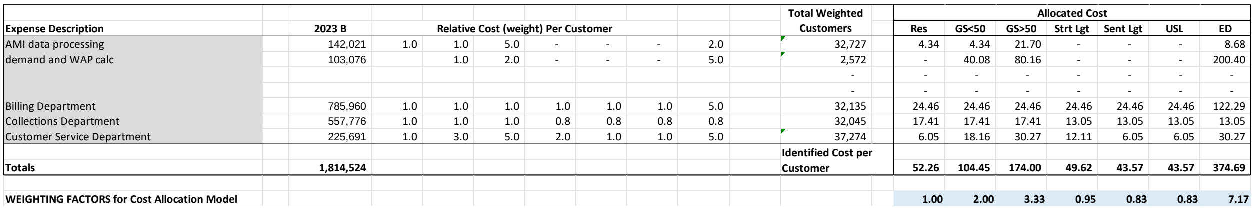
Preamble: The Application states:

"*Through this analysis, EPLC was able to align the Billing and Collection expenses to each rate class and thus calculate the factors shown below in Table 7-2*."

a) Please provide a copy of the analysis deriving the Billing and Collecting weighting factors.

EPLC's Response:

Table 7-3: Billing and Collecting Weighting Factors



									Total Weighted	Allocated Cost						
Expense Description	**2023 B**	**Relative Cost (weight) Per Customer**							**Customers**	**Res**	**GS<50**	**GS>50**	**Strt Lgt**	**Sent Lgt**	**USL**	**ED**
AMI data processing	142,021	1.0	1.0	5.0	-	-	-	2.0	32,727	4.34	4.34	21.70	-	-	-	8.68
demand and WAP calc	103,076		1.0	2.0	-	-	-	5.0	2,572	-	40.08	80.16	-	-	-	200.40
									-	-	-	-	-	-	-	-
									-	-	-	-	-	-	-	-
Billing Department	785,960	1.0	1.0	1.0	1.0	1.0	1.0	5.0	32,135	24.46	24.46	24.46	24.46	24.46	24.46	122.29
Collections Department	557,776	1.0	1.0	1.0	0.8	0.8	0.8	0.8	32,045	17.41	17.41	17.41	13.05	13.05	13.05	13.05
Customer Service Department	225,691	1.0	3.0	5.0	2.0	1.0	1.0	5.0	37,274	6.05	18.16	30.27	12.11	6.05	6.05	30.27
Totals	**1,814,524**								**Identified Cost per Customer**	**52.26**	**104.45**	**174.00**	**49.62**	**43.57**	**43.57**	**374.69**
WEIGHTING FACTORS for Cost Allocation Model										**1.00**	**2.00**	**3.33**	**0.95**	**0.83**	**0.83**	**7.17**

a)

7-VECC-53

Reference: Exhibit 7, page 6

Cost Allocation Model, Tab 7.2

a) Please explain why for the Residential class the number of meter reads is equal to the number of customers times 12 whereas for the GS<50, GS>50 and Embedded Distributor class the number is set equal to the number of customers.

b) Are there any customers that have more than one meter that is owned and/or read by EPLC?

    i. If yes, how many additional meters does this add to each customer class for meters owned by EPLC and meters read by EPLC?

EPLC's Response:

a) EPLC has updated the Cost Allocation Model to correct the GS,50, GS>50 and Embedded Distributor class to reflect the number of customers times 12 on Tab 7.2 Meter Reading.

b) There are no customers that have more than one meter that is owned/and or read by EPLC that is not on a separate account.

7-VECC-54

Reference: Exhibit 7, page 7

Preamble: The Application states:

"*Load profiles were derived using weather normalized 2022 and 2023 hourly load data; adjustments were made to align the 2023 load profiles with the proposed 2025 Load Forecast (i.e. consumption forecast).*"

a) Why weren't similar analyses carried to normalize the 2022 load profile for the customer classes and align the results with the 2025 Load Forecast and then the overall 2025 results calculated using the average of the 2025 results for the two years (2022 and 2023)?

EPLC's Response:

a) The weather normalized 2023 load profile was used because it is the best representation of EPLC's future load profiles. It would not be unreasonable to average results from multiple scaled weather normalized profiles, however, the 2022 profile is somewhat influenced by the COVID-19 pandemic as there were increased public safety measures in January 2022 due to the Omicron variant. These measures included temporarily closing public schools and requiring business to have employees work remotely. Residential weather-normalized peak demand in January 2022 was 6.9% higher than peak demand in January 2023, and General Service < 50 kW peak demand was 9.6% lower in 2022 than in 2023. Uncharacteristic demands in January would have an impact on all months after the weather normalized demands are scaled to the 2025 load forecast.

7-VECC-55

Reference: **Cost Allocation Model, Tab6.2**

a) Please explain why for the GS>50, the CCB and CCP values are both 233 when the forecast customer count is 235.

EPLC's Response:

EPLC has corrected the CCB and CCP values to 235 in the Cost Allocation Model, Tab 6.2.

7-VECC-56

Reference: **Exhibit 7, page 9**

Preamble: The Application states:

"*In absence of any rate mitigation there would be total bill impacts in excess of 10% for the Sentinel lighting rate class. Sentinel Light distribution rates increase in 2025 - 2027 so the total bill impact is 10%, and in 2028 distribution rates increase so it reaches the 80% revenue-to-cost floor. The lower Sentinel Light rate increases in 2025 and 2026 are offset by small increases to Residential and General Service < 50 rates*."

a) What would the revenue to cost ratios be for the GS>50, USL and Embedded Distributor classes if the following approach was used in setting the ratios for the 2025 to 2028 period:

- The R/C ratios for the Residential and Street Lighting classes are set at 94.15% for all years,
- The R/C ratios for Sentinel Lights and GS<50 for each year are set as proposed in the Application, and
- In each year, the GS>50, USL and Embedded Distributor class ratios are all set at the same value so as to yield the proposed overall Base Revenue Requirement.

EPLC's Response:

a) The R/C ratios in the described scenario are provided in the table below.

Table 7-4: R/C Ratios

Revenue-to-Cost Ratio				
Rate Class	**2025**	**2026**	**2027**	**2028**
Residential	94.15%	94.15%	94.15%	94.15%
GS <50	119.92%	119.92%	119.92%	119.92%
GS >50	120.59%	120.41%	120.15%	120.01%
Embedded	120.59%	120.41%	120.15%	120.01%
Street Light	94.15%	94.15%	94.15%	94.15%
Sentinel	55.41%	63.15%	74.24%	80.00%
USL	120.59%	120.41%	120.15%	120.01%

Exhibit 8- Rate Design

OEB Staff Interrogatories

8-Staff-59

Z Factor
Ref 1: Exhibit 8, page 19

Preamble:

Essex Powerlines states,

"Essex Powerlines has planned and implemented several strategies for mitigating the potential impact of extreme and severe weather events such as proactive vegetation management, disaster recovery planning and emergency response preparedness, however it could not have foreseen, planned or budgeted for the storm experienced on February 23."

Question(s):

a) Has Essex Powerlines taken any steps since the February 2023 storm to improve its risk assessment and risk management in light of increasing extreme weather events? If so, please describe.

b) Please provide Essex Powerlines annual budgeted and actual amounts for capital expenditures and OM&A related to emergency response which are included in base distribution rates for the period 2018 to date.

EPLC's Response:

a) Since the February 2023 storm, EPLC has taken steps to formalize its approach to risk assessment and risk management in light of the increasing extreme weather events. Historically, EPLC has relied on neighbouring utilities to provide mutual aid to each other where needed. This worked well and was used on several occasions. Following the ice storm of 2023, EPLC entered into an agreement with Ontario Mutual Assistance Program (ONMAG) and the South Central Ontario LDC Mutual Assistance Plan. These groups provide access to a greater number of resources across Ontario. It became apparent, as the ice storm was centrally located over Southwestern Ontario, that EPLC's current partnerships with neighbouring utilities would not be available to provide assistance as they were dealing with concurrent issues. EPLC's collaborative Control Room operations with Welland Hydro continue to improve EPLC's ability to concentrate efforts on dispatching and priority schedules during storm events. Ongoing risk assessment and risk management activities include evaluating specialized on-call services that may enhance storm responses through integration with existing outage management software.

b) Budget and actual amounts for Capital and OM&A:

Table 8-1: Emergency Response Budget OM&A

Emergency Response Budget OM&A			
Year	**Budget**	**Actual**	
2018	$281,289.00	$342,158.99	
2019	$307,890.00	$313,786.28	
2020	$310,200.00	$294,685.58	
2021	$323,016.00	$239,817.12	
2022	$326,534.00	$300,845.07	
2023	$275,214.00	$292,106.19	
2024	$274,525.00	$162,707.07	YTD

Emergency Response Budget Capital (O/H & U/G Reactive)			
Year	**Budget**	**Actual**	
2018	$115,864.00	$161,681.00	
2019	$150,311.00	$228,377.08	
2020	$153,317.00	$182,056.09	

2021	$219,978.00	$497,862.44	
2022	$159,511.00	$317,675.20	
2023	$220,960.00	$318,458.71	
2024	$229,798.36	$358,162.58	YTD

Figures noted as YTD are to June 30, 2024

8-Staff-60

RTSRs
Ref 1: RTSR Workform

Question(s):

a) Please confirm which historic year of RRR data has been used.
b) Please confirm which year of wholesale purchase volumes have been used.

EPLC's Response:

a) On Tab 3. RRR Data EPLC has used 2025 Load Forecast data. EPLC notes that this LF data was updated to the latest LF submitted with these Interrogatory responses.
b) On Tab 5. Historic Wholesale, EPLC has used 2023 actual volumes. EPLC notes that several updates were made in this data to correct typographical errors.

8-Staff-61

Low Voltage Charges
Ref 1: Exhibit 8, pages 9-10
Ref 2: RTSR Workform, sheet 9. LV Rates

Preamble:

The evidence in Exhibit 8 details how the LV expense is apportioned to rate classes and used to derive rates. It does not appear to explain how the LV charge of $1,767,704 is derived. The RTSR Workform appears to have escalated the 2023 volumes and 2023 charges by 2% each year to 2025.

Question(s):

a) Please provide the rationale for the 2% annual increase on volumes.
b) As a scenario, please calculate, and provide the derivation of the LV charge that would result if the 2024 host rates were used.

EPLC's Response:

a) EPLC has updated the low voltage costs based on actual HONI 2023 billing quantities and HONI's approved 2024 RTSRs.
b) EPLC confirms that the 2024 rates were used in the calculation.

School Energy Coalition (SEC)

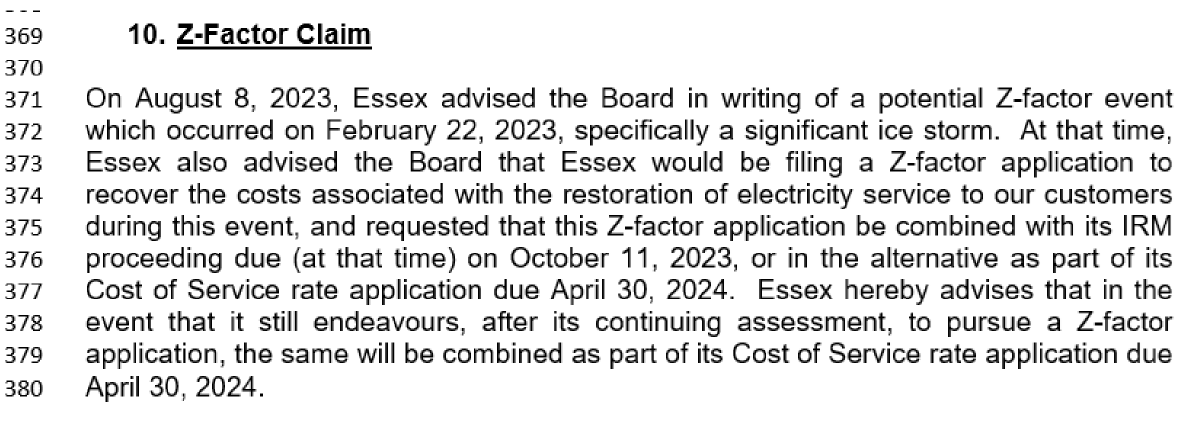
8-SEC-40

[Ex. 8, p. 15] Essex has applied for a Z-factor for a February 22, 2023 event.

a. Please provide copies of the correspondence Essex sent to the OEB on August 8, 2023 and any reply received from the OEB.
b. The Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008 states that the applicant should "apply to the Board for any amounts claimed under Z-factor treatment with the next rate application." Why did Essex not include the request for the Z-factor in its 2024 IRM Application, filed on October 24, 2023?
c. Please explain why the work being claimed to restore power is not part of Essex's normal Emergency Response costs.

EPLC's Response:

a) The correspondence of August 8, 2023 is attached as Attachment G. No response was received from the OEB.
b) Please see below the excerpt from EPLC's Manager' Summary, page 11, as part of the 2024 IRM application (EB-2023-0020).



10. Z-Factor Claim

On August 8, 2023, Essex advised the Board in writing of a potential Z-factor event which occurred on February 22, 2023, specifically a significant ice storm. At that time, Essex also advised the Board that Essex would be filing a Z-factor application to recover the costs associated with the restoration of electricity service to our customers during this event, and requested that this Z-factor application be combined with its IRM proceeding due (at that time) on October 11, 2023, or in the alternative as part of its Cost of Service rate application due April 30, 2024. Essex hereby advises that in the event that it still endeavours, after its continuing assessment, to pursue a Z-factor application, the same will be combined as part of its Cost of Service rate application due April 30, 2024.

c) Although EPLC has several strategies for mitigating the impact of extreme weather events, it could not have foreseen, planned or budgeted for the storm experienced on February 23, 2023, nor were such costs contemplated in EPLC's rates. In 2023, EPLC budgeted $181k for emergency response and incurred costs of $211k, which included responses to several other slightly less impactful storm events.

8-SEC-41

[Ex. 8, Table 8.23] Some of the numbers in Table 8.23 do not agree with the Bill Impact Model. For example, for GS > 50 kW Distribution Table 8.23 says 5.54% and the Bill Impact says 2.34%. Please update as required.

EPLC's Response:

The Bill Impact Model has been updated to include any changes resulting from these interrogatories and/or corrections and has been re-submitted as "EPLC_TariffSchedule_BillImpactModel_IRR_20240730".

Vulnerable Energy Consumers Coalition (VECC)

8-VECC-57

Reference: Exhibit 8, pages 7 - 8

RTSR Workform, Tab 3 and Tab 5

a) Please confirm that the RRR data used in the RTSR Workform Tab3 and the HONI billing data used in Tab 5 are based on the same year.
b) Does EPLC have any customers with behind the meter generation (i.e., embedded generation) that is subject to gross load billing for purposes of HONI's RTSRs charged to EPLC?
    i. If yes, does EPLC propose to apply its RTSR rates to these customers on a gross load basis, and, if so, have the billing demands in Tab 3 been adjusted accordingly?

EPLC's Response:

a) The RRR data in Tab 3 of the RTSR workform is 2025 load forecast data and the HONI billing data in Tab 5 is 2023 actual data.
b) EPLC does not have any customers subject to gross load billing.

8-VECC-58

Reference: Exhibit 8, page 8

a) Please update the proposed 2025 Retail Service Charges to reflect the 3.6% inflation factor for 2025 as published by the OEB on June 20, 2024.

EPLC's Response:

EPLC has updated the proposed 2025 Retail Service Charges in the Tariff Schedule and Bill Impact Model to reflect the 3.6% inflation factor for 2025 as published by the OEB on June 20, 2024, to match the table below.

Table 8-2: Updated 2025 Retail Service Charges

Retail Service Charges		**Current charge**	**Inflation factor - June 20, 2024**	**Proposed charge**
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	117.02	3.60%	121.23
Monthly fixed charge, per retailer	$	46.81	3.60%	48.5
Monthly variable charge, per customer, per retailer	$/cust.	1.16	3.60%	1.2
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.69	3.60%	0.71
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	-0.69	3.60%	-0.71
Service Transaction Requests (STR)				0
Request fee, per request, applied to the requesting party	$	0.59	3.60%	0.61
Processing fee, per request, applied to the requesting party	$	1.16	3.60%	1.2
Electronic Business Transaction (EBT) system, applied to the requesting party				
up to twice a year		no charge		no charge
more than twice a year, per request (plus incremental delivery costs)	$	4.68	3.60%	4.85
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.34	3.60%	2.42

8-VECC-59

Reference: Exhibit 8, pages 9 - 10

a) The forecast 2025 kWh and kW used in Table 8-13 don't match the proposed load forecast. Please reconcile.
b) Please provide the LV costs based on: i) the actual HONI 2023 billing quantities and ii) HONI's approved 2024 RTSRs.

EPLC's Response:

a. The 2025 forecast kWh and kW have been updated and re-submitted as a result of interrogatories and/or corrections.
b. EPLC has updated the LV costs based on 1.) actual HONI 2023 billing quantities and ii.) HONI's approved 2024 RTSR's.

8-VECC-60

Reference: Exhibit 8, page 12

a) Please update the 2025 Specific Charge For Access To The Power Poles in Table 8-15 to reflect the 3.6% inflation factor for 2025 as published by the OEB on June 20, 2024.
b) Does this updated rate for the 2025 Specific Charge For Access To The Power Poles impact EPLC's forecasted Other Revenue for 2025? If yes, please provide an updated version of Appendix 2-H.

EPLC's Response:

a) The 4.8% inflation factor that applies to the wireline pole attachment charge is locked and so EPLC has manually changed the value in the tab '5. Final Tariff Schedule' to be $37.78*1.036. However, if macros are enabled when tab 5 is selected, it may revert back to the incorrect number.

b) The update above will affect EPLCs forecasted Other Revenue and Appendix 2-H has been updated accordingly.

8-VECC-61

Reference: Exhibit 8, page 13

Chapter 2 Appendices, Appendix 2-R

a) Please confirm that in Appendix 2-R the A(2) values include embedded generation directly connected to EPLC's system (per the Appendix's notes).

EPLC's Response:

a) EPLC confirms that the A(2) values in Appendix 2R include embedded generation.

Exhibit 9- Deferral and Variance Accounts

OEB Staff Interrogatories

9-Staff-62

Ref 1: EB-2017-0039, Decision and Order

Preamble:

In reference 1, the OEB directs "Essex Powerlines to report to the OEB's Audit & Investigation group when the audit reports' remaining recommendations are complete. The OEB expects the report to be filed within one year, by August 31, 2019. In addition, Essex Powerlines is directed to file this report with its next rate setting application."

Reference 1 further notes that rate setting application refers to Price Cap IR or Custom IR and exclude IRM application.

Questions(s):

a) Please provide the report referred to in reference 1.

EPLC's Response:

EPLC filed this report on November 5, 2018 as part of its Price Cap IR application (EB-2018-0031). The report is attached as Attachment H.

9-Staff-63

DVA Continuity Schedule
Ref 1: 2024 DVA Continuity Schedule, Tab 2a, Cells C60, BW26, BW28 & BV28

Preamble:

References Cell C60 states that "RRR balance for Account 1580 RSVA - Wholesale Market Service Charge should equal to the control account as reported in the RRR. This would include the balance for Account 1580,Variance WMS – Sub-account CBR Class B."

OEB staff notes that the control account 1580 in the continuity schedule excludes balances in CBR Class A and CBR Class B. The control account in RRR includes the balances of the two sub-accounts. Therefore, in the variance column, it is expected to see a variance in cell BW26 equaling the RRR balance of 1580 Sub-account CBR Class B in cell BV28.

Question(s):

a) Please explain why the variance in Cell BW26 is not equal to the RRR balance in Cell BV28.
    a. Please revise the schedules or the RRR filing (2.1.7) as needed. If not, please explain.

EPLC's Response:

a) The variance in cell BW26 was not equal to the RRR balance in cell BV28 due to an error in the DVA Continuity schedule. EPLC has revised the schedule and notes that there are no revisions needed to RRR.

9-Staff-64

DVA
Ref 1: Prescribed interest rates / Ontario Energy Board (oeb.ca)

Preamble:

The OEB has recently published its prescribed interest rate for deferral and variance account balances for Q3 2024 of 5.20%.

Question(s):

a. Please update the DVA schedules accordingly using the updated prescribed interest rate.

EPLC's Response:

a) EPLC has updated the DVA schedules as required using the Q3 2024 5.20% rate provided by the OEB.

9-Staff-65

Ref 1: Exhibit 9, pages 15-16

Ref 2: Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, page 65
Ref 3: Accounting Guidance on Wireline Pole Attachment Charges, July 20, 2018, page 3

Preamble:

Essex Powerlines is requesting the disposition of Account 1508 – Pole Attachment Revenue Variance (credit balance of $685,105) and to continue using this account as appropriate, depending on the outcome of any OEB review initiatives.

Section 2.9.1.7 of the Filing Requirements states that distributors are to provide a table showing the calculation of the account balance, showing at a minimum, the annual balance broken down customer type, if applicable and:

- the number of poles used in the calculation.
- the pole attachment charge incorporated in rates.
- the updated charge.

Pole Attachment Revenue Variance Accounting Guidance states that “once an LDC has had the new pole attachment charge incorporated in a cost-based rate application, the variance account will no longer be required and must be closed after disposition of the last of the amounts that have been tracked.”

Question(s):

a) Please provide the information as noted in the Section 2.9.1.7 of the Filing Requirement to support the Account 1508 – Pole Attachment Revenue variance balances requested in this application for disposition.
b) Please explain what Essex Powerlines means by “to continue using this account as appropriate, depending on the outcome of any OEB review initiatives,” in light of the Pole Attachment Charges Accounting Guidance.

EPLC’s Response:

a) The table below fulfills the filing requirements of Section 2.9.1.7.

Table 9-1: Supporting Information for Filing Requirements of Section 2.9.1.7

Year	# Poles	Allowable Rate	Updated Rate	Account 1508 Balance
2018	2,173	$ 22.35	$ 28.09	$ 4,157.67
2019	5,849	$ 22.35	$ 43.63	$ 124,466.72
	17	$ 22.35	$ 41.73	$ 329.46
2020	6,450	$ 22.35	$ 44.50	$ 142,867.50
2021	6,792	$ 22.35	$ 44.50	$ 150,442.80
2022	7,050	$ 22.35	$ 34.76	$ 87,490.50
2023	7,230	$ 22.35	$ 36.05	$ 99,051.00
				$ 608,805.65

b) EPLC amends their submission to request to close this account.

9-Staff-66

Ref 1: Exhibit 9, pages 16-17
Ref 2: Regulatory Treatment of Impacts Arising from the COVID-19 Emergency, EB-2022-0133, June 17, 2021, page 20
Ref 3: 2024 DVA Continuity Schedule, Tab 2b, Cells AT110 (2022 transactions), BD110 (2023 transactions)

Preamble:

Essex Powerlines is requesting the disposition of account: Account 1509 – Impacts Arising from COVID-19 with a debit balance of $108,194. which represents waived late payment charges plus interest.

Section 4.2.2 of the COVID-19 Guidance states that the Exceptional Pool of costs will be eligible for recoveries up to 100% provided they are prudently incurred and material, and subject to an ROE plus 300 bps limitation, as outlined in the Staff Proposal.

Question(s):

a) Please provide evidence to demonstrate how Essex Powerlines meets the requirements as noted in Sec 4.2.2. of the COVID-19 Guidance, given that the waived late payment falls under the Exceptional Pool of costs.
b) Please provide Essex Powerlines' thought of closing this account given the 2022 transactions (Cell AT110: credit balance of $148) and 2023 transactions (Cell BD110: credit balance of $3) are negligible. If not, please explain.

EPLC's Response:

a) EPLC meets the requirement for 100% recovery of costs as the costs incurred were related to foregone revenues from waived service charges, which are eligible per the Exceptional Pool of costs as outlined in Section 4.2.2 of the Covid-19 Guidance. Further to the provisions of that guidance, EPLC incurred these costs causally and prudently as a result of the global pandemic to ease the financial burden on its customers in a very uncertain time; EPLC has not exceeded the approved ROE plus 300 bps means test in any year since 2020; and the $108k balance in Account 1509 exceeds EPLC's materiality threshold at time of occurrence of these costs; that materiality threshold was $65k.
b) EPLC is in agreement with closing this account as 2022 and 2023 balances are negligible and any potentially large additions to the account would be unlikely.

9-Staff-67

Ref 1: Exhibit 9, pp. 18-19
Ref 2: Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, pp.63-64

Preamble:

Essex Powerlines is requesting the disposition of account: Account 1592 – PILS and Tax Variances (credit balance of $1,698,140).

Section 2.9.1.5 of the Filing Requirements states that distributors are to provide calculations for accelerated CCA differences per year, based on actual capital additions. These calculations should include:

- The undepreciated capital cost (UCC) continuity schedules for each year, itemized by CCA class.
- The calculated PILs/tax differences.
- The grossed-up PILs/tax differences,
- Any other applicable information.

Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable.

A reconciliation of these amounts to the amounts presented in Account 1592 sub-account for CCA changes in the DVA continuity schedule.

Question(s):

a) Please provide the information as noted in Section 2.9.1.5 of the Filing Requirement to support the Account 1592 – PILS and Tax Variances requested in this application for disposition.

EPLC's Response:

a) Details required per Section 2.9.1.5 of the Filing Requirements are presented in Attachment I. EPLC confirms that it had no ICM/ACM applications, and therefore, Account 1592 contains no such related amounts.
A minor change has been made in the DVA continuity schedule to reflect an adjustment to the 2023 addition to Account 1592, reflecting EPLC's final 2023 PILs return.
A change has also been made in the DVA continuity schedule to reflect an adjustment to the projected 2024 addition to Account 1592.
Table 9-21 below summarizes the amended request for disposition of Account 1592.

Table 9-2: Revised Table 9-21: Account 1592 Claim in Exhibit 9

Table 9-21: Account 1592 Claim

Description	Principal	Interest	Total
December 31, 2023 Balance	($1,300,640)	($60,402)	($1,361,042)
Forecast PILs adj January to December 2024	($175,733)		($175,733)
Interest January to December 2024		($78,912)	($78,912)
Total Balance for Disposition	($1,476,373)	($139,314)	($1,615,687)

9-Staff-68

Ref 1: Exhibit 9, pp.17-18

Ref 2: EB-2017-0039, Decision and Order, page 113
Ref 3: The Accounting Procedures Handbook, FAQs, March 2025

Preamble:

Essex Powerlines requested the disposition of a debit balance of $147,817 in Account 1576, Accounting Changes under CGAAP. Essex Powerlines states that: In EPLC's 2018 Cost of Service rate application, $3,217,101 was approved for disposal based on actual and forecast costs to May 31, 2018.

The Q&A of the Accounting Procedures Handbook FAQs dated March 15 provides the guidance on the journal entries that should be used to implement the disposition of Account 1575 IFRS-CGAAP Transitional PP&E Amounts and Account 1576 CGAAP Accounting Changes. The FAQ states that:

The account balance plus the rate of return is disposed through a separate rate rider, distinct from any other rate rider that may be approved to implement the combined disposition of the remaining Group 1 and Group 2 accounts. As indicated in the July 2012 FAQs, the approved disposition of the account balance for both Account 1575 and Account 1576 would be reflected as an offset to depreciation expense over the approved amortization period.

The journal entry shows that the disposition of the rate riders refunded is debited in USoA 4080 distribution revenues and credited in USoA 1100 Customer Accounts Receivable.

Question(s):

a) Please confirm that the balance of $147,817 represents that the total refunding of Account 1576 rate riders using the actual volumes is greater than the approved refunding of Account 1576 rate riders using the actual and forecast volumes.
b) Please confirm that Essex Powerlines has recorded the accounting entries while disposing the account 1576 balance and refunding to the customers for the Account 1576 rate riders in accordance with the APH FAQs dated March 2015.
c) Based on the March 2015 FAQs, there is no true-up of Account 1576 rate riders because the rate riders are recorded in Account 4080 rather than Account 1595. Please provide Essex Powerlines thought of writing off the balance of $147,817 in this application.

EPLC's Response:

a) EPLC confirms that the balance of $147,817 represents the variance between the total refund of Account 1576 rate riders using actual volumes and the approved refund of Account 1576 rate riders using actual and forecast volumes.
b) EPLC confirms that it has recorded the accounting entries while disposing the Account 1576 balance and refunding to the customers for the Account 1576 rate riders in accordance with the APH FAQs dated March 2015.
c) Upon further investigation of this balance and based upon the guidance related to disposition of Account 1576, EPLC is in agreement that the $147,817 balance should be written off.

School Energy Coalition (SEC)

9-SEC-42

[Ex. 9, Table 9-17]

a. With respect to Account 1508 Pole Attachment Revenue Variance Account, please update Table 9-17 to include a forecast of 2024 incremental revenue.
b. Please explain why Essex is requesting to continue the Pole Attachment Revenue account when the Filing Requirements state "Further transactions would not be expected to be recorded in the account".

EPLC's Response:

a) Table 9-17 has been amended to include the 2024 forecasted incremental revenue. The forecast is based on 7,200 telecommunication poles valued at the difference between the 2024 pole attachment charge of $37.78 and the pole attachment charge incorporated into rates of $22.35.

Table 9-3: Revised Table 9-17 Account 1508 Claim in Exhibit 9

Table 9-17: Account 1508 Claim

Description	Principal	Interest	Total
December 31, 2023 Balance	($608,806)	($42,876)	($651,682)
Adjustments			$0
Forecasted 2024 Incremental Revenue	($111,096)		($111,096)
Interest January to December 2024		($38,479)	($38,479)
Total Balance for Disposition	**($719,902)**	**($81,355)**	**($801,257)**

b. EPLC amends their submission to request to close this account.

9-SEC-43

[Ex. 9, Table 9-19] With respect to Account 1535 Smart Grid OM&A Deferral Account, please explain why Essex has requested disposition when the balance is below the materiality threshold of $90k.

EPLC's Response:

EPLC proposed discontinuation of Account 1535 Smart Grid OM&A Deferral in its 2018 rate rebasing (EB-2017-0039) and as such, it amends its submission to request disposition of this balance.

Vulnerable Energy Consumers Coalition (VECC)

9-VECC-62

Reference: Exhibit 9, page

a) Please update Table 9-1 (EPLC DVA Balances) for any changes made as a result of responding to interrogatories or updating of evidence.

EPLC's Response:

Table 9-1 has been updated to reflect all changes made.

Table 9-4: Revised Table 9-1 EPLC DVA Balances in Exhibit 9

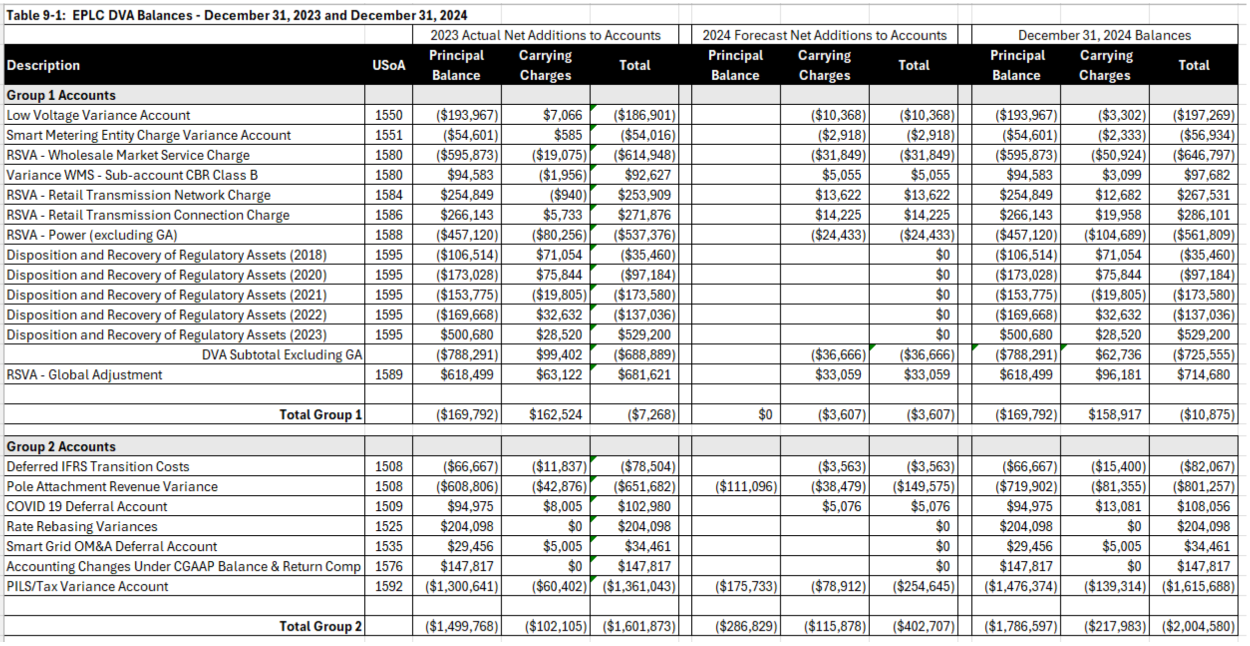


Table 9-1: EPLC DVA Balances - December 31, 2023 and December 31, 2024

		2023 Actual Net Additions to Accounts			2024 Forecast Net Additions to Accounts			December 31, 2024 Balances		
Description	**USoA**	**Principal Balance**	**Carrying Charges**	**Total**	**Principal Balance**	**Carrying Charges**	**Total**	**Principal Balance**	**Carrying Charges**	**Total**
Group 1 Accounts										
Low Voltage Variance Account	1550	($193,967)	$7,066	($186,901)		($10,368)	($10,368)	($193,967)	($3,302)	($197,269)
Smart Metering Entity Charge Variance Account	1551	($54,601)	$585	($54,016)		($2,918)	($2,918)	($54,601)	($2,333)	($56,934)
RSVA - Wholesale Market Service Charge	1580	($595,873)	($19,075)	($614,948)		($31,849)	($31,849)	($595,873)	($50,924)	($646,797)
Variance WMS - Sub-account CBR Class B	1580	$94,583	($1,956)	$92,627		$5,055	$5,055	$94,583	$3,099	$97,682
RSVA - Retail Transmission Network Charge	1584	$254,849	($940)	$253,909		$13,622	$13,622	$254,849	$12,682	$267,531
RSVA - Retail Transmission Connection Charge	1586	$266,143	$5,733	$271,876		$14,225	$14,225	$266,143	$19,958	$286,101
RSVA - Power (excluding GA)	1588	($457,120)	($80,256)	($537,376)		($24,433)	($24,433)	($457,120)	($104,689)	($561,809)
Disposition and Recovery of Regulatory Assets (2018)	1595	($106,514)	$71,054	($35,460)			$0	($106,514)	$71,054	($35,460)
Disposition and Recovery of Regulatory Assets (2020)	1595	($173,028)	$75,844	($97,184)			$0	($173,028)	$75,844	($97,184)
Disposition and Recovery of Regulatory Assets (2021)	1595	($153,775)	($19,805)	($173,580)			$0	($153,775)	($19,805)	($173,580)
Disposition and Recovery of Regulatory Assets (2022)	1595	($169,668)	$32,632	($137,036)			$0	($169,668)	$32,632	($137,036)
Disposition and Recovery of Regulatory Assets (2023)	1595	$500,680	$28,520	$529,200			$0	$500,680	$28,520	$529,200
DVA Subtotal Excluding GA		($788,291)	$99,402	($688,889)		($36,666)	($36,666)	($788,291)	$62,736	($725,555)
RSVA - Global Adjustment	1589	$618,499	$63,122	$681,621		$33,059	$33,059	$618,499	$96,181	$714,680
Total Group 1		($169,792)	$162,524	($7,268)	$0	($3,607)	($3,607)	($169,792)	$158,917	($10,875)
Group 2 Accounts										
Deferred IFRS Transition Costs	1508	($66,667)	($11,837)	($78,504)		($3,563)	($3,563)	($66,667)	($15,400)	($82,067)
Pole Attachment Revenue Variance	1508	($608,806)	($42,876)	($651,682)	($111,096)	($38,479)	($149,575)	($719,902)	($81,355)	($801,257)
COVID 19 Deferral Account	1509	$94,975	$8,005	$102,980		$5,076	$5,076	$94,975	$13,081	$108,056
Rate Rebasing Variances	1525	$204,098	$0	$204,098			$0	$204,098	$0	$204,098
Smart Grid OM&A Deferral Account	1535	$29,456	$5,005	$34,461			$0	$29,456	$5,005	$34,461
Accounting Changes Under CGAAP Balance & Return Comp	1576	$147,817	$0	$147,817			$0	$147,817	$0	$147,817
PILS/Tax Variance Account	1592	($1,300,641)	($60,402)	($1,361,043)	($175,733)	($78,912)	($254,645)	($1,476,374)	($139,314)	($1,615,688)
Total Group 2		($1,499,768)	($102,105)	($1,601,873)	($286,829)	($115,878)	($402,707)	($1,786,597)	($217,983)	($2,004,580)

9-VECC-63

Reference: Exhibit 9, page 16

"As there is the potential for the Pole Attachment rates to continue to change as a result of further OEB direction, EPLC requests to continue using this account as appropriate depending on the outcomes of any OEB review initiatives."

a) What new initiatives does EPLC contemplate occurring with respect to pole attachments over the next 4 year?

EPLC's Response:

a) EPLC is not anticipating any specific new pole attachment charge changes and amends their submission to request to close this account.

9-VECC-64

Reference: Exhibit 9, page 17

Description	Principal	Interest	Total
December 31, 2023 Balance	$29,456	$5,005	$34,461
Adjustments			$0
Interest January to December 2024		$1,617	$1,617
Total Balance for Disposition	**$29,456**	**$6,622**	**$36,078**

"In its 2018 COS Application, EPLC requested approval to dispose of this account balance based on the 8 principal balance at the time of filing plus forecasted carrying charges up to April 30, 2018."

a) Please provide the amounts disposed of from this account in 2018.
b) Please provide the Board order which approved the continuation of this account (accounting order).

EPLC's Response:

a) A principal balance of $91,626 and an interest amount of $5,781 was approved for disposition in EPLC's 2018 Cost of Service (EB-2017-0039).
b) This account was proposed for discontinuation in 2018; as such, balances should not have accrued since that time.

9-VECC-65

Reference: Exhibit 9, page 18 / EB-2017-0039 Decision and Order August 23, 2018, Appendix G DVA Continuity Schedules

a) The DVA Continuity Schedule filed as part of the 2018 Board Order shows a total IFRS transition claim of $3,217,101. Please reconcile this figure with the $3,364,917.67 shown on page 18 under 1576 Charges.

EPLC's Response:

The difference between the total IFRS transition claim of $3,217,101 and the balance under 1576 Charges of $3,364,917.67 is the $147,817 balance of Account 1576 that was requested for disposition.

Upon further investigation of this balance and based upon the guidance related to disposition of Account 1576, EPLC amends their submission to dispose of this balance.

Please refer to 9-Staff-68.

ATTACHMENTS

Attachment A- 2024 Budget

Essex Powerlines Corporation
Income Statement
2023 Proj - 2024 Budget

	2023 Budget	2023 Year-End Projection	Incr(Decr) 2023 Proj v 2023 Budget	2024 Budget	Incr(Decr) 2024 Budget v 2023 Budget	Incr(Decr) 2024 Budget v 2023 Projection
Revenue: Sale of energy & distribution revenue	$84,119,640	$79,782,653	(5.16%)	$82,658,748	(1.74%)	3.60%
Cost of energy purchased	(70,287,158)	(65,633,711)	(6.62%)	(67,941,354)	(3.34%)	3.52%
Distribution revenue	13,832,482	14,148,942	2.29%	14,717,394	6.40%	4.02%
Miscellaneous Revenues						
PV Generation Revenue	23,500	24,000	2.13%	23,500	0.00%	(2.08%)
Pole Rentals	147,500	160,000	8.47%	150,000	1.69%	(6.25%)
Town Billing Revenue	329,600	329,600	0.00%	329,600	0.00%	0.00%
Gain/(Loss) on Sale/Retirement of Assets	30,000	2,401	(92.00%)	30,001	0.00%	1149.52%
Gain/(Loss) on Foreign Exchange	(3,000)	(1,000)	(66.67%)	(3,002)	0.07%	200.20%
Interest	273,094	507,581	85.86%	297,385	8.89%	(41.41%)
Other Income/(Deductions)	665,626	640,093	(3.84%)	738,833	11.00%	15.43%
Total Miscellaneous Revenue	1,466,320	1,662,675	13.39%	1,566,317	6.82%	(5.80%)
Total Net Revenue	15,298,802	15,811,617	3.35%	16,283,711	6.44%	2.99%
Operating, Maintenance & Administration Expense						
Administration & General	3,917,391	4,101,425	4.70%	4,379,986	11.81%	6.79%
Billing & Collecting	1,882,399	2,020,086	7.31%	1,978,140	5.09%	(2.08%)
PV Generation Costs	14,633	14,579	(0.37%)	14,631	(0.01%)	0.36%
Distribution (O&M)	2,598,007	2,835,894	9.16%	2,614,225	0.62%	(7.82%)
Other expenses						
Total OM&A	8,412,430	8,971,984	6.65%	8,986,982	6.83%	0.17%
Operational Income	6,886,372	6,839,633	(0.68%)	7,296,729	5.96%	6.68%
Amortization of PPE	(3,202,903)	(3,196,745)	(0.19%)	(3,404,875)	6.31%	6.51%
Amortization of Intangibles	(292,996)	(340,162)	16.10%	(458,225)	56.39%	34.71%
Income Before Interest	3,390,473	3,302,726	(2.59%)	3,433,629	1.27%	3.96%
Interest	(1,357,642)	(1,643,466)	21.05%	(1,480,862)	9.08%	(9.89%)
Income Before Non-recurring items and Tax	2,032,831	1,659,260	(18.38%)	1,952,767	(3.94%)	17.69%
Non-recurring items	0	0	0.00%	(201,000)	0.00%	0.00%
Current Tax	(304,925)	(82,963)	(72.79%)	(87,589)	(71.28%)	5.58%
Net Income	1,727,906	1,576,297	(8.77%)	1,664,178	(3.69%)	5.58%
Other comprehensive Income						
Items that will not be classified to profit or loss						
Items that will be reclassified subsequently to profit or…						
Total comprehensive income for the year	1,727,906	1,576,297	(8.77%)	1,664,178	(3.69%)	5.58%
EBITDA	6,886,372	6,839,633	(0.68%)	7,296,729	5.96%	6.68%

ESSEX POWERLINES CORPORATION
Statement of Retained Earnings
2023 Proj-2024 Budget

	2023 Year-End Projection	2024 Budget
Retained Earnings, beginning of year	$ 13,792,539	$ 14,268,836
Net Income	1,576,297	1,664,178
Dividends Declared	(1,100,000)	(1,117,000)
Retained Earnings, end of year	14,268,836	14,816,014

Essex Powerlines Corporation
Balance Sheet
2023 Proj - 2024 Budget

	2023 Budget	2023 Projection	2024 Budget
Assets			
Current assets			
Cash and cash equivalents	$1,050,000	$409,799	$664,799
Accounts receivable	5,653,567	5,987,028	5,977,028
Due from related parties	278	0	0
Unbilled revenue	5,835,527	6,507,080	6,442,080
Materials and supplies	944,636	1,617,109	1,577,109
Prepaid expenses	154,710	286,072	288,572
Total current assets	13,638,718	14,807,088	14,949,588
Non-current assets			
Property, plant and equipment	75,771,815	77,854,410	83,814,158
Intangible assets	1,963,338	1,860,886	2,776,068
Total non-current assets	77,735,153	79,715,296	86,590,226
Total assets	91,373,871	94,522,384	101,539,814
Regulatory balances	12,418,819	9,804,734	7,054,734
Total assets and regulatory balances	103,792,690	104,327,118	108,594,548
Liabilities			
Current Liabilities			
Accounts payable and accrued liabilities	9,396,951	10,460,587	10,067,348
Due to related parties	15,061	419,149	419,149
Long-term debt due within one year	3,597,976	3,406,749	4,328,199
Income tax payable	25,000	10,000	35,000
Customer and other deposits	548,219	1,630,552	1,898,052
Dividends payable	1,100,000	1,100,000	1,117,000
Total current liabilities	14,683,207	17,027,037	17,864,748
Non-current liabilities			
Long-term debt	41,151,158	35,342,380	36,492,064
Post-employment benefits	2,726,918	2,010,279	2,135,279
Deferred revenue	9,363,673	11,108,878	12,219,235
Deferred tax liability	3,645,162	3,753,745	4,151,245
Total non-current liabilities	56,886,911	52,215,282	54,997,823
Total liabilities	71,570,118	69,242,319	72,862,571
Equity			
Share capital	15,772,801	15,772,801	15,772,801
Retained earnings	14,236,434	14,268,836	14,816,014
Accumulated other comprehensive income (loss)	1,485,267	1,804,333	1,804,333
Total equity	31,494,502	31,845,970	32,393,148
Total liabilities and equity	103,064,620	101,088,289	105,255,719
Regulatory balances	728,070	3,238,829	3,338,829
Total liabilities, equity and regulatory balances	103,792,690	104,327,118	108,594,548

See accompanying notes to the financial statements

Essex Powerlines Corporation
Statement of Cash Flows
2023 Proj-2024 Budget

	2023 Projection	2024
Cash provided by (used in):		
Operating activities:		
Net income (loss) from operations	$ 1,576,297	$ 1,664,178
Add items not involving cash:		
Amortization of capital & intangible assets	3,544,898	3,871,113
Amortization of deferred revenue	(275,830)	(328,697)
Change in deferred tax assets or liabilities	597,500	397,500
Post-employment benefits	(175,000)	125,000
Change in regulatory balances	2,600,002	2,850,000
Net change in non-cash working capital **	2,455,809	933,211
	10,323,676	**9,512,305**
Investing activities:		
Property, plant & equip and Intangible assets	(9,732,166)	(10,746,043)
	(9,732,166)	**(10,746,043)**
Financing activities:		
Dividends paid	(1,084,000)	(1,100,000)
Contributions in aid of construction	2,790,300	1,439,054
Change in long-term liabilities	1,332,190	1,149,684
	3,038,490	**1,488,738**
Increase (decrease) in cash and cash equivalents (incl. Bank indebtedness) during the period	**3,630,000**	**255,000**
Cash and cash equivalents (incl. Bank indebtedness), beginning of period	**(3,220,201)**	**409,799**
Cash and cash equivalents (incl. Bank indebtedness), end of period	**409,799**	**664,799**
Net changes in non-cash working capital **:		
Current Assets (INCR)/DECR	608,972	112,500
Current Liabilities INCR/(DECR)	1,846,837	820,711
	2,455,809	933,211

Attachment B- 2023 Scorecard

Scorecard - Essex Powerlines Corporation

5/21/2024

Performance Outcomes	Performance Categories	Measures		2019	2020	2021	2022	2023	Trend	Target	
										Industry	Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		94.78%	93.27%	90.84%	91.45%	91.02%	🟢↓	90.00%	
		Scheduled Appointments Met On Time		93.15%	94.46%	93.15%	98.68%	97.06%	🟢↑	90.00%	
		Telephone Calls Answered On Time		82.62%	65.17%	76.62%	80.94%	81.05%	🟢↑	65.00%	
	Customer Satisfaction	First Contact Resolution		98.99%	99.15%	99.08%	99.6%	99.4			
		Billing Accuracy		99.96%	99.92%	99.95%	99.95%	99.90%	🟢↓	98.00%	
		Customer Satisfaction Survey Results		83%	86%	86%	86%	87%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness		83.00%	83.00%	85.00%	85.00%	85.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	🟢→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	🟢→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	🟢→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.27	1.23	2.02	1.82	2.48	🔴↑		1.24
		Average Number of Times that Power to a Customer is Interrupted [2]		0.84	0.95	0.89	0.84	1.07	🔴↑		0.74
	Asset Management	Distribution System Plan Implementation Progress		37.5%	57%	76.13%	97.65%	99.84			
	Cost Control	Efficiency Assessment		2	2	2	1				
		Total Cost per Customer [3]		$580	$577	$564	$625				
		Total Cost per Km of Line [3]		$10,907	$10,979	$10,789	$12,005				
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Connection of Renewable Generation**	New Micro-embedded Generation Facilities Connected On Time		100.00%			100.00%	100.00%	🟢→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.57	0.72	0.76	0.85	1.03			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.31	1.32	1.25	1.27	1.21			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.00%	9.00%	9.00%	9.00%	9.00%			
			Achieved	7.30%	6.14%	6.79%	6.09%	4.50%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.

Legend:

5-year trend

↑ up ↓ down → flat

Current year

🟢 target met 🔴 target not met

Attachment C- MSA for Shared Services

AMENDMENT TO MASTER SERVICES AGREEMENT Section 6.02

THIS AMMENDMENT effective this 1st day of January, 2004

BETWEEN:

(ESSEX POWER CORPORATION)

(hereinafter referred to as " **EPC** ")

OF THE FIRST PART

and

(ESSEX POWERLINES CORPORATION)

(hereinafter referred to as " **EPL**")

OF THE SECOND PART

Administration Costs

6.02 EPL shall reimburse EPC for its actual costs including overhead, which without limiting the generality of the foregoing shall include EPC direct labour, engineering design and review costs including overhead applicable to EPL, plus labour overhead calculated at 45% plus 6% rate of return on all costs.

IN WITNESS WHEREOF the Parties have duly executed this Amendment on the date first above written:

ESSEX POWER CORPORATION

[redacted]

ESSEX POWERLINES CORPORATION

[redacted]

MASTER AGREEMENT

THIS AGREEMENT made this 25 day of Sept , 2002

BETWEEN:

(ESSEX POWER CORPORATION)

(hereinafter referred to as " **EPC** ")

OF THE FIRST PART

and

(ESSEX POWERLINES CORPORATION)

(hereinafter referred to as " **EPL**")

OF THE SECOND PART

WHEREAS EPC and EPL are duly incorporated pursuant to Section 142, Schedule A of the *Electricity Act, 1988.*

AND WHEREAS both EPC and EPL will operate as separate corporate entities, notwithstanding the provisions of this Agreement;

AND WHEREAS the parties have agreed that EPC will provide finance, engineering, and management support for EPL's electrical distribution system on a fee-for-service basis and EPC shall provide such and other products and as may be agreed by the parties from time to time.

AND WHEREAS the parties acknowledge and agree that in providing goods and services EPC acts as an independent contractor and not as an agent, partner, or servant;

AND WHEREAS the parties shall consult as frequently as may be desirable to ensure that EPL and its customers receive adequate, economical and effective electrical distribution and ancillary services;

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth, and for other good and valuable considerations for the sum of two ($2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, with each other, as follows:

1. Definitions

1.01 **"Capital Cost"** means the cost incurred for materials, equipment, overhead, and labour to provide capital works.

1.02 **"Capital Works"** means those expansions and upgrades to EPL's electrical distribution system as may be agreed from time to time pursuant to Article 5 of this Agreement.

1.03 **"Customer "** means all related to customer, which without limiting the generality of the foregoing shall include customer billing collection of unpaid accounts, and customer relations, etc.

1.04 **"Direct Costs"** means the cost incurred directly by EPL for its own operations including but not limited to electrical power costs for Standard Supply Service, IMO costs, Hydro One Networks Incorporated Transmission costs, Debt Retirement Charge, Retail/Wholesale Settlement costs, Ministry of Finance OEB Regulatory costs, Board of Directors meetings and conferences, EDA dues, MEARIE insurance and other insurance premiums, legal, accounting, audit and consulting fees, etc.

1.05 **"Easements"** means any permissions, concessions, permits, licenses, interests, ways, privileges, easements and right-of-way to install, operate and maintain part or parts of the electrical distribution system over real property.

1.06 **"Extraordinary Costs"** means those unusual and unanticipated costs as more particularly described in Article 6.04.

1.07 **"Administration Costs"** means costs incurred by EPC to manage business, finances, and day to day operations.

1.08 **"Transition Costs"** means one-time costs of reconfiguring or adding any system, policy, procedure, legal arrangement, employee relationship, etc. necessary for the Parties to operate under this Agreement and under electric utility industry restructuring as defined in *The Energy Competition Act, 1998* and its associated regulations.

2. Term

2.01 Unless terminated in accordance with Article 10.01, the term of this Agreement shall be from January 1, 2002 to and including December 31, 2002 and renewed year by year thereafter, unless either party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. Management Support

3.01 EPC agrees to manage in a professional manner, EPL's electrical distribution system in the areas serviced by EPL, in the former Municipality of Leamington, former Towns of Tecumseh, LaSalle, and Amherstburg, and the former Village of St. Clair Beach hereinafter referred to as the "EPL Service Area".

3.02 EPC shall safeguard and maintain EPL's management requirements including but not limited to: decision-making, contractual agreements, and OEB compliance.

4. Finance Support

4.01 EPC shall act in accordance with EPL's financial requirements including but not limited to: audited financial statements, variance analysis, retail services and settlements, variance accounts, reconciliation of approved regulatory taxes to actual taxes, internal audit reports, annual statistics, accounts receivable, accounts payable, budgeting, capital planning and wholesale market monitoring and compliance.

5. Engineering Support

5.01 EPC shall safeguard and maintain EPL's engineering requirements including but not limited to: OEB compliance, maintenance and capital standards, supply planning, and distribution system design.

5.02 EPC shall engineer and mange the required expansions and upgrades to EPL's electrical distribution system in a timely, competent and workmanlike manner at EPL's request, which shall hereinafter be referred to as "Capital Works" provided that such Capital Works have been designed in accordance with good engineering principles applicable in the Province of Ontario. EPL shall pay EPC the fees and charges for engineering support.

6. Costs

Direct Costs

6.01 EPL shall assume and be directly responsible for its Direct Costs.

Administration Costs

6.02 EPL shall reimburse EPC for its actual costs including overhead, which without limiting the generality of the foregoing shall include EPC direct labour, engineering design and review costs including overhead applicable to EPL, plus labour overhead calculated at 45% plus 6% rate of return on all costs.

6.03 Work may be progress billed or billed upon completion to EPL and EPL shall pay at least quarterly of receipt. Billing may include intercompany transfer and journal entries to record the transfer.

Extraordinary Costs

6.04 EPL agrees to reimburse EPC for any extraordinary costs over and above normal costs to which EPC may be put resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, and the like provided such equipment failures are not caused by negligence on the part of EPC to provide management, engineering, and finance support.

Transition Costs

6.05 EPL shall pay EPC for transition costs associated with electric utility industry restructuring.

Renewal

6.06 Upon renewal of the term of this Agreement and any subsequent renewals, EPC may adjust the support costs and Extraordinary Costs upon ninety (90) days prior notice in writing to EPL provided that, if EPL does not accept the adjusted costs and the parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Article 8 of this agreement.

7 Payment

7.01 EPC shall submit to EPL at least quarterly, costs in providing support services. All costs shall provide sufficient detail of the costs incurred and the description of the undertaken by EPC. EPL shall transfer payment to EPC via intercompany transfers.

7.02 EPC will submit details of any extraordinary costs to EPL for review and EPL will pay as per Article 7.01 at least quarterly.

8 Confidentiality

8.01 EPC shall ensure confidential information relating to EPL's specific consumers, retailers, or generators is not disclosed to any party without the consent of EPL. EPC shall obtain in writing such consent except where confidential information is required to be disclosed for billing, market operations, law enforcement, legal requirement or for the processing of past due accounts.

9 Arbitration

9.01 The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in Article 9.02.

9.02 Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

9.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

9.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

9.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

10 Termination

10.01 In the event of non-performance by either party of its obligations under this Agreement, the other party may at its sole option elect to terminate this Agreement provided that the defaulting party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

11 Insurance

11.01 EPL and EPC shall jointly provide and keep in force an insurance policy in the amount of not less than $20 million in respect of the performed by EPC under the terms of this Agreement.

11.02 EPC agrees to endorse its insurance coverage with EPL as an additional named insured to cover any liability of EPL resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of EPL, or to those for whom EPL is at law responsible.

11.03 All policies shall contain a clause requiring the insurer to give EPC or EPL, as the case may be, two hundred (200) days written notice prior to canceling insurance coverage.

11.04 Both Parties will notify the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) regarding liability insurance implications.

12 Warranty

12.01 PC provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

13. New Business Opportunities

13.01 EPC intends to explore and develop new business opportunities for the retail sale of products and to its customers and those customers in areas now serviced by EPL.

13.02 EPC agrees to disclose to EPL its new business and marketing plans, including projected revenues and expenses as they pertain to EPL, for new business opportunities as they arise from time to time provided that such plans are treated as confidential as between the Parties unless otherwise agreed in writing by EPC.

14. Notices

14.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) to the President, EPC at: 360 Fairview Avenue West, Suite 218, Essex, Ontario N8M 3G4

b) to the General Manager, EPL at: 360 Fairview Avenue West, Suite 318, Essex, Ontario N8M 3G4

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

15. Amendments

15.01 Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

16. Headings

16.01 The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main test of this Agreement.

17. Governing Law

17.01 This Agreement shall be construed in accordance with the laws of the Province of Ontario.

18. Successors

18.01 This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

18.02 The Parties explicitly acknowledge and agree that the term of this Agreement shall remain in full force and effect and be binding upon new business corporations incorporated under the Business Corporations Act to whom assets and liabilities will be transferred as required pursuant to the provisions of the Energy Competition Act, 1998.

18.03 For the purposes of this Agreement, whenever the term EPC or EPL is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

19. Regulatory Changes

19.01 The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 8.

20. Relationship

20.01 The parties acknowledge and agree that EPC shall act as an independent contractor providing its services under this Agreement and the Parties further acknowledge and agree that nothing in this Agreement shall be deemed or construed to be the formation of a partnership between EPC and EPL.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

ESSEX POWER CORPORATION

[redacted]

ESSEX POWERLINES CORPORATION

[redacted]

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this 1st day of March , 2009

BETWEEN:

(ESSEX POWER SERVICES CORPORATION)

(hereinafter referred to as "**EPSC**")

OF THE FIRST PART

and

(ESSEX POWERLINES CORPORATION)

(hereinafter referred to as "**EPL**")

OF THE SECOND PART

WHEREAS EPSC and EPL are duly incorporated pursuant to Section 142, Schedule A of the *Electricity Act, 1998.*

AND WHEREAS both EPSC and EPL will operate as separate corporate entities, notwithstanding the provisions of this Agreement;

AND WHEREAS the parties have agreed that EPL shall provide such and other products and services as may be agreed by the parties from time to time.

AND WHEREAS the parties acknowledge and agree that in providing goods and services EPSC acts as an independent contractor and not as an agent, partner, or servant;

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth, and for other good and valuable considerations for the sum of two ($2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, with each other, as follows:

1. Definitions

1.01 **"Administration Costs"** means costs incurred by EPC to manage business, finances, and day to day operations.

1.02 **"Customer Service Costs"** means the cost incurred by a party to bill and collect and to provide related customer services.

1.03 **"Customer Services"** means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing, collection of unpaid accounts, and customer relations, etc.

1.04 **"Extraordinary Costs"** means those unusual and unanticipated costs as more particularly described in Article 5.05.

1.05 **"Vehicle and Equipment Cost"** means the cost of trucks and other motorized vehicles, and equipment used in operations, maintenance, administration and capital works of EPL.

2. Term

2.01 Unless terminated in accordance with Article 11.01, the term of this Agreement shall be from January 1, 2008 to and including December 31, 2008 and renewed year by year thereafter, unless either party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. Electrical Services

3.01 EPL agrees to perform in a good and workmanlike manner EPSC's request for electrical services which may include the installation and maintaining of street lights or any other high voltage electrical services that may be requested by EPSC that is not within EPL's distribution system, in the former Municipality of Leamington, former Towns of Tecumseh, LaSalle, and Amherstburg, and the former Village of St. Clair Beach hereinafter referred to as the "EPL Service Area".

3.02 In providing electrical services for EPSC, EPL shall maintain the minimum performance standards as required by EPSC and in conjunction with regulatory agencies such as the Electrical Safety Authority (ESA).

3.03 EPL shall follow good utility practice in providing services as requested by EPSC as to prevent exposure to EPSC for liability reasons.

4. Costs

4.01 **Administrative Costs**

4.02 EPSC shall reimburse EPL for its actual costs including overhead, which without limiting the generality of the foregoing shall include EPL direct labour, engineering design and review costs including overhead applicable to EPSC, plus labour overhead according to Schedule A.

4.03 Work may be progress billed or billed upon completion to EPSC and EPSC shall pay at least quarterly of receipt. Billing may include intercompany transfer and journal entries to record the transfer.

4.04 Material/Accounts Payable/Inventory Costs

EPSC shall pay EPL the fees and charges more particularly outlined in Schedule "A" for material used either from on hand inventory or specifically ordered and delivered for the required work. These costs may also include subcontractor or contracted services charges that are required to complete the work as requested by EPSC.

4.05 Vehicle/Equipment Costs

EPSC shall pay EPL the fees and charges more particularly outlined in Schedule "A" as EPSC's contribution towards the utilization of trucks, other motorized vehicles and equipment used by EPL to provide services as requested by EPSC.

4.06 Direct Costs

EPSC shall assume and be directly responsible for its Direct Costs. Direct costs may include EPSC specific training required by EPL's employees.

4.07 Extraordinary Costs

EPSC agrees to reimburse EPL for any extraordinary costs over and above normal service costs to which EPL may have resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, and the like provided such equipment failures are not caused by negligence on the part of EPL.

4.08 Renewal

Upon renewal of the term of this Agreement and any subsequent renewals, EPL may adjust the Administrative costs, Vehicle/Equipment Costs, and Extraordinary Costs upon ninety (90) days prior notice in writing to EPSC provided that, if EPSC does not accept the adjusted costs and the parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Article 10 of this agreement.

5. Invoicing

5.01 EPL shall submit invoices to EPSC on a monthly basis, for costs in performing services under this agreement. All costs shall provide sufficient detail of the costs incurred and the description of the services undertaken by EPL. EPSC shall transfer payment to EPL via intercompany transfers or by cheque.

5.02 EPL will submit details of any extraordinary costs to EPSC for review prior to completion and EPSC will pay as per Article 6.01 at least quarterly.

6. Arbitration

6.01 The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in Aricle10.02.

6.02 Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

6.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

6.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

6.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

7. Termination

7.01 In the event of non-performance by either party of its obligations under this Agreement, the other party may at its sole option elect to terminate this Agreement provided that the defaulting party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

8. Insurance

8.01 EPL and EPSC shall jointly provide and keep in force an insurance policy in the amount of not less than $20 million in respect of the services performed by EPL under the terms of this Agreement.

8.02 EPSC agrees to endorse its insurance coverage with EPL as an additional named insured to cover any liability of EPL resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of EPL, or to those for whom EPL is at law responsible.

8.03 All policies shall contain a clause requiring the insurer to give EPSC or EPL, as the case may be, two hundred (200) days written notice prior to canceling insurance coverage.

8.04 Both Parties will notify the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) regarding liability insurance implications.

9. **Warranty**

9.01 EPL provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

10. **Notices**

10.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) to the President, EPSC at: 360 Fairview Avenue West, Suite 218, Essex, Ontario N8M 3G4

b) to the General Manager, EPL at: 360 Fairview Avenue West, Suite 318, Essex, Ontario N8M 3G4

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

11. **Amendments**

11.01 Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

12. **Headings**

12.01 The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main test of this Agreement.

13. **Governing Law**

13.01. This Agreement shall be construed in accordance with the laws of the Province of Ontario.

14. **Successors**

14.01. This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

14.02. The Parties explicitly acknowledge and agree that the term of this Agreement shall remain in full force and effect and be binding upon new business corporations incorporated under the Business Corporations Act to whom assets and liabilities will be transferred as required pursuant to the provisions of the Energy Competition Act, 1998.

14.03. For the purposes of this Agreement, whenever the term EPSC or EPL is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

15. Regulatory Changes

15.01. The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 10.

16. Relationship

16.01. The parties acknowledge and agree that EPL shall act as an independent contractor providing its services under this Agreement and the Parties further acknowledge and agree that nothing in this Agreement shall be deemed or construed to be the formation of a partnership between EPSC and EPL.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

[redacted]

EPL

Per:

[redacted]

General Manager RICHARD DIMMEL

UTILISMART SERVICES AGREEMENT

AGREEMENT NUMBER: **UCSA-2023-87**

THIS AGREEMENT made as of **July 07, 2023** with an initial term start date of **November 01, 2023**, or "Go Live" date, as defined by the Services implementation project plan, whichever comes first (the "**Initial Term Start Date**");

BETWEEN:

UTILISMART CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario and having an office at 201-555 Southdale Rd. East, London, Ontario N6E 1A2 (hereinafter, **"Utilismart"** or **"Company"**)

- and –

ESSEX POWERLINES CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario and having an office at 2730 Highway 3, Oldcastle Ontario N0R 1L0, (hereinafter, **"Customer"**)

1. SCHEDULES

The following Schedules attached hereto shall be deemed to form part of this Agreement as if specifically restated herein:

SCHEDULE A -
SCHEDULE B -

SCHEDULE C -

In the event of a conflict between the terms of any schedule and the terms in the main body of this Agreement, the terms of the schedule shall govern.

2. SCOPE OF SERVICES

a. The Company shall provide, and the Customer shall pay for, the software term license and services outlined in SCHEDULE A (the "Services") in accordance with the terms and conditions herein.

b. The Company may modify the manner in which the Services are provided to the Customer during the Initial Term or Renewal Term (as such terms are defined in Section 6(a) below)

Address (street): 201-555 Southdale Road East
Address (City): London, Ontario N6E 1A2
Telephone: +1 (888) 652-0689 ext. 2533
Email: mkarlicic@utilismartcorp.com

or at such other address the addressee may from time to time have notified the addressor pursuant to this Section 5. A Notice shall be deemed to have been sent and received on the day it is delivered personally or by courier or electronic internet communication. If such day is not a business day or if the Notice is received after 5:00 p.m., the Notice shall be deemed to have been sent and received on the next business day.

6. TERM AND TERMINATION

a. Initial and Renewal Terms. Subject to the early termination rights described in Sections 6(b) and 6(c) below, the term of this Agreement shall be sixty (60) months, commencing on the date hereof (the "Initial Term"). The Agreement shall automatically be renewed for successive twelwe (12) month term(s) (each a "Renewal Term"), unless 120 days' notice of termination is provided by any party to the other party in writing prior to the end of the Initial Term. The "Renewal Term" shall be for 12-month period following the "Initial Term" and shall continue until 120 days' notice of termination is provided by a party in writing to the other party prior to the end of a Renewal Term.

b. Other Termination Rights. If there has been a breach or default of the terms of this Agreement (as defined below) by either party (the "Defaulting Party"), then the other party may terminate this Agreement after giving the Defaulting Party Notice, in accordance with the provisions of this Agreement, of the breach or default and 30 days to remedy the same or 10 business days in the case of a failure to make, when due, any payment pursuant to this Agreement. In the event the breach or default is not remedied with the time periods described above, this Agreement shall terminate immediately. Either party shall have the option to terminate this Agreement upon termination of the provision of any services by any third party which are included as a portion of the Services.

For the purposes of this Agreement, a breach or default will include the following:
(i) A violation of any term of this Agreement; and
(ii) The failure to make, when due, any payment required pursuant to this Agreement.

c. Effect of Expiry or Termination. Subject to Sections 6(a) – (b), upon expiry or termination of this Agreement, the following shall apply:

(1) Utilismart will immediately stop performing Services, unless otherwise agreed to in writing by the Customer;
(2) The Customer will pay Utilismart any fees described in SCHEDULE A which have been invoiced by Utilismart and remain payable by the Customer under the terms of this Agreement for Services provided by Utilismart up to and including the date of termination;
(3) The termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination

and shall not affect any continuing obligations of either of the parties under this Agreement.

7. INTELLECTUAL PROPERTY RIGHTS

a. Customer Proprietary Information. The Company acknowledges and agrees that it shall have no right, title, claim, interest, security interest or lien ("Interest") in any specifications, designs, plans, drawings, data, software, computer systems, prototypes or other technical or business information ("Proprietary Information") and disclosed to the Company by or on behalf of the Customer in connection with this Agreement ("Customer Proprietary Information"), regardless of whether any such information constitutes a trade secret or is competitively sensitive, or in any Proprietary Rights (as defined below) with respect thereto, and disclaims any such Interest in any of the Customer Proprietary Information or such Proprietary Rights. The Customer hereby grants or shall grant to The Company a personal, non-exclusive, non-transferable, royalty-free license (without the right to sublicense, except to affiliates) during the Term, to use, execute, reproduce, display, perform and copy such Customer Proprietary Information (including the right to provide such information to subcontractors) for the sole purpose of performing the Services and only to the extent necessary to do so. As used in this Agreement, "Proprietary Rights" means, with respect to any item, all trade secret, copyright, patent, trademark, service mark, certification mark, trade dress or other intellectual property or proprietary rights in all countries related to such item

or any part thereof, any extensions or renewals of the foregoing, and any registrations, patents or applications with respect to the foregoing.

b. The Company Proprietary Information. The Customer acknowledges and agrees that it shall have no Interests in any Proprietary Information disclosed to the Customer by or on behalf of the Company in connection with this Agreement ("The Company Proprietary Information"), regardless of whether any such information constitutes a trade secret or is competitively sensitive, or in any Proprietary Rights with respect thereto, and disclaims any such Interest that it might otherwise have in any of the Company Proprietary Information or such Proprietary Rights. Where necessary for the proper performance of the Services under this Agreement, the Company will grant to the Customer a personal, non-exclusive, non-transferable, royalty-free license (without the right to sublicense, except to affiliates) during the Term, to use, execute, display, perform and copy any such Company Proprietary Information for use solely in connection with Customer's receipt of the Services.

8. LIMITATIONS OF LIABILITY

a. Neither party shall be liable to the other party for any special, indirect, incidental, consequential or punitive damages of any character, including but not limited to loss of use, loss of profit, past and future, additional out-of-pocket expenses incurred by the other, or other claims resulting from, arising out of, in connection with or in anyway incidental to any act or omission of the other party related to the provisions of this Agreement, including without limitation, claims of third parties.

TO THE MAXIMUM EXTENT PERMITTED BY LAW, THE LIABILITY OF THE COMPANY TO THE CUSTOMER FOR ANY REASON AND UPON ANY CAUSE OF ACTION WHATSOEVER, WHETHER IN CONTRACT OR TORT, SHALL BE LIMITED TO THE AGGREGATE SUM OF ALL FEES PAID BY

THE CUSTOMER UNDER THIS AGREEMENT IN RESPECT OF THE SERVICES PROVIDED BY THE COMPANY (EXCLUDING ALL FEES OR EXPENSES RELATING TO SERVICES NOT DIRECTLY PROVIDED BY THE COMPANY SUCH AS FEES RELATED TO THE RESELLING OF THIRD PARTY SERVICES) IN THE ONE (1) MONTH PERIOD PRIOR TO THE DAY ON WHICH THE CAUSE OF ACTION AROSE.

b. The Company shall not be liable for any costs, losses, damages, legal costs and expenses, liability, claims and demands resulting from or arising in connection with any use of the Customer's usernames or passwords. The Customer is responsible for ensuring that the usernames and passwords are kept confidential. While the Company agrees to take commercially reasonable measures to protect its systems, the Customer acknowledges and agrees that under no circumstances shall the Company be held responsible or liable for situations where the data stored or communicated through the Company's website interface are accessed by third parties through illegal or illicit means, including situations where such data is accessed through the exploitation of security gaps, weaknesses or flaws, if unknown to the Company at the time, which may exist in the Host System (as defined herein). The Company simply stores and facilitates the transmission of private electronic communications. Electronic communications on the Company's Host System are private, and only under situations where explicitly required or allowed by law will such communications be accessed, intercepted, disclosed, or used without the consent of at least one of the parties to the communication.

c. While the Company agrees to take commercially reasonable steps to ensure that the Services being provided by it under this Agreement will perform as represented to Customer in this Agreement, the Company does not represent or warrant that the Services will continuously operate or be provided without error or malfunction. The Customer agrees that in the event of an error, malfunction, or failure of the Services to perform as represented herein (an "Error"), the Company shall first be given a comprehensive written report from Customer as to the Errors being experienced in as much detail as reasonably possibly so as to assist Company in rectifying same. Company agrees to promptly review and to make commercially reasonable efforts to remedy the Error without delay. The parties shall cooperate so as to allow Company to effect any required changes, patches, updates, etc. in a timely manner and to minimize the disruption to Customer.

d. The parties agree that the Company shall have no liability for any of Customer's damages or losses arising as a result of an Error if: (i) the Company rectifies the Error within a reasonable period of time, (ii) the Customer fails to follow the error reporting procedure set out in this section, or (iii) the Error is caused by:

    (aa) any product or service, including but not limited to hardware, software or telecommunications services supplied by a third party, and/or including but not limited to all products and services which the Company offers to its Customer as a reseller but which are delivered by a third party entity (a "Third Party Service"); or

    (bb) any Error that is caused by or results from a Third Party Service; or (cc) any force majeure (being a strike, labour trouble, inability to get materials or services, power failure, restrictive governmental laws or regulations, riots, insurrection, sabotage, rebellion, war, act of God, or any other similar reason or cause) beyond the control of the Company.

Customer shall also take all commercially reasonable steps necessary so as to comply with the Company's advice and direction as to accessing and using the Services so as to reduce the likelihood of Errors.

9. GENERAL

a. Entire Agreement. This Agreement, together with the Schedules attached hereto, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all prior agreements, representations, warranties or other provisions, express or implied, collateral, statutory or otherwise, relating to the subject matter hereof except as herein provided.

b. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The parties irrevocably attorn to the jurisdiction of the courts of Ontario with respect to any matter arising under or related to this Agreement.

c. Amendments. This Agreement will not be amended or supplemented except by written agreement entered into by an authorized signatory of each of the parties.

d. Waivers. No waiver of any obligation or any remedy for breach of any provision of this Agreement will be effective or binding unless made in writing and agreed to by an authorized signatory of the party purporting to give the same and, unless otherwise provided, will be limited to the specific obligation or breach waived.

e. Independent Contractor. Nothing contained in this Agreement shall be construed to constitute either party as a partner, employee or agent of, or joint venture with the other party. Neither party shall have any authority to hold itself out as acting on behalf of or to legally bind the other.

f. Binding Agreement. This Agreement shall endure to the benefit of and shall be binding on and enforceable by the parties, and where the context so permits, their respective successors and permitted assigns. Except as otherwise set out in this Agreement, this Agreement shall not confer upon any other person except the parties and their respective successors and permitted assigns, any rights, interests, obligations or remedies under this Agreement.

g. Assignment. Utilismart may assign this Agreement or any of its rights or obligations hereunder, in whole or in part, with the prior written consent of the other party (said consent will not be unreasonably withheld).

h. Severability. In the event that any of the covenants herein shall be held unenforceable or declared invalid for any reason whatsoever, to the extent permitted by law, such unenforceability or invalidity shall not affect the enforceability or validity of the remaining provisions of this Agreement and such unenforceable or invalid portion shall be severable from the remainder of this Agreement.

i. Execution in Counterparts. This Agreement may be executed in counterparts and delivered by electronic means and the counterparts together shall constitute one and the same Agreement.

10. SURVIVAL

a. Neither the expiration of the Term nor the earlier termination of this Agreement will release either of the parties from any obligation or liability incurred prior to such expiration or termination.

b. In addition to the terms of this Agreement that by their very nature survive the expiry of termination of this Agreement, the terms of Article 4 (Confidential Information) Article 7 (Intellectual Property Rights) and Article 8 (Limitation of Liability) shall survive the expiration or earlier termination of this Agreement for a period of five (5) years.

[Remainder of page intentionally left blank. The next page is the execution page.]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

SCHEDULE C – TERMS OF USE

The following conditions and Terms of Use apply to all access and use of the Services by any of Customer and its users ("Users").

Notwithstanding anything herein to the contrary, any discrepancy between this Schedule C and the Agreement shall be resolved in accordance with the provisions of this Schedule C.

By Customer's execution of the Agreement, Customer accepts and agrees to comply with these Terms of Use in connection with its access to and use of the GBT Services. UtilityAPI is an express beneficiary of these Terms of Use, and by entering into the Agreement, Customer and Utilismart expressly acknowledge and agree that (i) Utilismart acts as trustee for UtilityAPI with respect to all rights contemplated hereunder, (ii) Utilismart agrees to accept such trust and hold and enforce such rights on behalf of UtilityAPI, and (iii) UtilityAPI shall also have the right to enforce these Terms of Use against Customer.

No amount of consideration is payable by Customer or UtilityAPI to the other in respect of these Terms of Use or the services described herein.

All capitalized terms used herein have the meanings provided in these Terms of Use.

1. CERTAIN DEFINITIONS

(a) "Administrative Data" means all administrative data generated through or by use of the GBT Services (e.g. number of accountholder authorizations, identities of the authorizing accountholders, and the scope of accountholder data that was authorized for release) and includes accountholder authorizations to release data to third parties.

(b) "Documentation" means UtilityAPI's physical or electronic user manuals, handbooks, and guides for the GBT Services.

(c) "GBT Services" means access to and use of UtilityAPI's utility data access platform for the Green Button Toolset and any associated or related services provided by UtilityAPI.

(d) "Service Data" means Utility Data and Administrative Data, collectively.

(e) "Term" means the term of the UtilityAPI SOW.

(f) "Utility Data" means, collectively, all accountholder meter, tariff, consumption and billing data provided by, on behalf of, or at the direction or authorization of Customer (including but not limited to data provided by Utilismart or any third-party energy service provider) to UtilityAPI for processing or transmittal through the GBT Services.

(g) "UtilityAPI SOW" means the service order entered into by UtilityAPI with Utilismart or its subcontractor setting forth the specific scope and term of the GBT Services to be provided by UtilityAPI with respect to Customer's GBT implementation.

2. SERVICES

(a) Access to GBT Services. During the Term and subject to the terms and conditions of these Terms of Use, Customer shall have the non-exclusive right to access and use the GBT Services in accordance with the UtilityAPI SOW and the Documentation.

(b) Unauthorized Use. Customer shall use commercially reasonable efforts to prevent unauthorized access to or use of the GBT Services, and will notify Utilismart or UtilityAPI promptly of any such unauthorized access or use of which it becomes aware.

(c) Authorized Persons. Customer is responsible for identifying and authenticating all of its employees, consultants, contractors, and agents who are authorized to access and use the GBT Services on its behalf ("Authorized Persons"), for approving access by such Authorized Persons to the GBT Services, for controlling against unauthorized access by Authorized Persons, for maintaining the confidentiality of usernames, passwords and accounts, and for ensuring compliance by such Authorized Persons with these Terms of Use. Customer is responsible and liable for all uses of the GBT Services resulting from access provided directly or indirectly by Customer.

(d) No Uptime Guarantees. Except to the extent that any such assurance may be provided in the applicable UtilityAPI SOW, UtilityAPI makes no warranty or assurance as to uptime or availability of the GBT Services.

(e) Service Suspension. Notwithstanding any other provision herein, Customer's access to the GBT Services may be suspended: (i) if UtilityAPI reasonably determines that there is a threat or attack on the GBT Services or on UtilityAPI systems or networks, (ii) if UtilityAPI reasonably believes that Utilismart, Customer or any of their Authorized Users is in violation of any provision of these Terms of Use or that their continued use of the GBT Services poses a systems, security or legal risk to UtilityAPI or Customer (any such suspension, a "Service Suspension").

In addition, a Service Suspension may be effected if Utilismart or its subcontractor fails to pay UtilityAPI amounts due with respect to Customer's subscription to the GBT Services. Customer acknowledges and agrees that UtilityAPI shall have no liability to Customer of any kind with respect to any such Service Suspension for nonpayment. Customer's sole recourse with respect to any such suspension shall be against Utilismart.

(f) Right to Modify Services. UtilityAPI may, in its sole discretion, change some or all of the functionality or any component of the GBT Services or make any modification for the purpose of improving the performance, correcting problems, or revising features.

(g) Ancillary Code. UtilityAPI may develop or provide software tools or code to facilitate Customer's implementation of and access and use of the GBT Services ("Ancillary Code"). Subject to any specific written terms and conditions applicable to such Ancillary Code, Utilismart may provide Customer with a non-transferable, non-exclusive, non-assignable, limited right to use such Ancillary Code solely in connection with the GBT Services during the Term. For greater certainty, no amounts shall be payable to UtilityAPI by Customer in respect of any Ancillary Code.

(h) Reservation of Rights by UtilityAPI. Subject to the limited and non-exclusive rights of use and access expressly provided to Customer herein, UtilityAPI or its licensors reserve all right, title and interest in and to the GBT Services (including all Ancillary Code).

Without limiting the foregoing, Customer acknowledges that the GBT Services are proprietary to UtilityAPI and/or its licensors, and that UtilityAPI and/or its licensors retain exclusive ownership of the GBT Services (including all underlying technology, software, patents, and knowhow), the Documentation, the Ancillary Code, other software and materials developed or delivered by or on behalf of UtilityAPI in connection with the GBT Services, all modifications or derivatives of any of the foregoing, and all intellectual property rights, including trade secrets rights, relating thereto. No rights are granted to Customer with respect to the GBT Services other than such limited and non-exclusive rights of access as are expressly set forth herein and subject to the terms of the applicable UtilityAPI SOW.

(i) Feedback. If Customer (including any Authorized Person) provides Utilismart or UtilityAPI with any feedback or suggestions regarding the GBT Services, Customer grants UtilityAPI an unlimited, irrevocable, perpetual, sublicensable, royalty-free license to use or share any such feedback or suggestions for any purpose without any obligation or compensation to Customer or any Authorized User. For clarity, this use right also applies to any feedback that may have been provided to Customer by any other Authorized Person.

(j) Non-UtilityAPI Products. Any use by Customer of any software applications or other products that interoperate with the GBT Services (a "Non-UtilityAPI Product"), and any exchange of data between Customer and any Non-UtilityAPI provider, product or service, is solely between Customer and the applicable provider and is subject to the terms and conditions of such provider. UtilityAPI does not warrant or support Non-UtilityAPI Products, unless expressly provided otherwise in a writing signed by UtilityAPI. There is no guarantee that the GBT Services will interoperate as expected with any Non-UtilityAPI Product or that if the GBT Services do so interoperate, that they will continue to do so.

(k) Export Compliance. The GBT Services, Ancillary Code, and derivatives of either may be subject to export laws and regulations of Canada, the United States, and other jurisdictions. Customer represents that it is not named on any Canadian or U.S. government denied-party list. Customer will not access or use any GBT Services or Ancillary Code in a Canadian- or US-embargoed country or region and will not import, export or re-export, or allow the import, export or re-export of, any element of the GBT Services (or any direct product thereof) in violation of any Canadian, United States or other applicable export laws, restrictions or regulations.

(l) Restrictions on Use. Customer shall not:

i. use the GBT Services except in strict accordance with the Agreement, these Terms of Use, the Documentation, and applicable laws and government regulations,

ii. lease, sell, license, distribute, sublicense, allow access to or otherwise make any GBT Services available to any third party (including but not limited to any unauthorized affiliate of Customer) other than as permitted by these Terms of Use or by UtilityAPI in writing,

iii. incorporate any element of the GBT Services into any products or services except as specifically permitted by UtilityAPI in writing,

iv. attempt to gain unauthorized access to the GBT Services or UtilityAPI's systems or networks, or permit direct or indirect access to or use of the GBT Services in a way that circumvents a contractual limit,

v. interfere with or disrupt the integrity or performance of the GBT Services or take any action which imposes an unreasonable or disproportionately large burden on UtilityAPI's infrastructure or resources,

vi. take any action or make any attempt to change, enhance or otherwise modify any part of the GBT Services,

vii. without UtilityAPI's prior written consent, conduct any security test, scan or probe of the GBT Services,

viii. use or attempt to use any data mining, robots, or similar data gathering and extraction tools to gather any data from GBT Services, except to the extent specifically permitted in the Documentation,

ix. frame or mirror any part of the GBT Services, other than as specifically permitted by the Documentation or by UtilityAPI in writing,

x. access or use the GBT Services to build or support (or to assist a third party in building or supporting) a competitive product or service,

xi. disassemble, decompile, reverse engineer, adapt or otherwise attempt to gain access to any software component of the GBT Services, discover the source code, object code or underlying structure, ideas, know-how or algorithms relevant to the GBT Services,

xii. copy, modify, translate, or create derivative works of the GBT Services or any part, feature, function or user interface not released under an open-source license,

xiii. allow the removal, alteration, covering, or obscuring of any UtilityAPI trade name, trademark or logo on the GBT Services,

xiv. use the GBT Services to store or transmit spam, malicious code, viruses, any unsolicited marketing communications or other commercial electronic messages (as such term is defined in applicable legislation) to third parties, infringing, libelous, or otherwise unlawful or tortious material, or any material in violation of any third-party privacy, intellectual property, or other right, or

xv. use, or allow the use of, the GBT Services for any unfair or deceptive practices or in contravention of any federal, state, provincial, municipal, local, foreign, or other applicable law, or rules and regulations of regulatory or administrative organizations.

3. UTILITY DATA

(a) Data Consents. Prior to transferring or permitting the transfer of any Utility Data for processing or transmittal through the GBT Services, Customer shall make such disclosures and obtain such consents from accountholders or other applicable third parties as are required under applicable law, rules or regulations.

(b) Responsibility for Data. Customer shall be responsible to UtilityAPI for the legality of all Utility Data and shall allow the transmission through the GBT Services of only such Utility Data for which all necessary consents, permissions, rights and licenses have been obtained, including all necessary consents and rights to provide UtilityAPI with the limited license set forth in clause 3(c) below.

(c) Limited Rights to Use Service Data. Customer grants UtilityAPI (and its agents and service providers) the limited, non-exclusive, royalty-free license to access and use Service Data only (i) as reasonably necessary to provide the GBT Services; (ii) to prevent or address service or technical problems or to provide implementation services or technical support; or (iii) as may be required by law. Subject to the limited rights granted herein, UtilityAPI acquires no right, title or interest under these Terms of Use in or to Service Data.

UtilityAPI may collect and use technical data and other information related to the performance of the GBT Services (such as feature usage, efficiency metrics and metadata) in connection with and for purposes of product development and improvement.

(d) Effect of Expiration or Termination. Upon the expiration or termination of the Term, Customer shall no longer be able to access or use the GBT Services; however, Customer may, by making a request through Utilismart, arrange for UtilityAPI to make all Service Data available for electronic retrieval by Customer for a period of 30 days after such expiration or termination. Thereafter UtilityAPI may delete or render inaccessible any stored Utility Data.

4. **DISCLAIMER OF WARRANTIES**. THE GBT SERVICES ARE PROVIDED BY UTILITYAPI WITHOUT WARRANTIES TO CUSTOMER, AND UTILITYAPI DISCLAIMS ANY AND ALL SUCH WARRANTIES. **ANY WARRANTIES TO THE CUSTOMER IN RESPECT OF THE GBT SERVICES SHALL BE SOLELY BETWEEN CUSTOMER AND UTILISMART PURSUANT TO THE TERMS OF THE CUSTOMER CONTRACT.**

5. **EXCLUSION OF LIABILITY. CUSTOMER UNDERSTANDS AND ACKNOWLEDGES THAT AS NO FEES ARE PAID BY CUSTOMER TO UTILITYAPI, THE SOLE RECOURSE OF CUSTOMER WITH RESPECT TO THE GBT SERVICES WILL BE AS BETWEEN CUSTOMER AND UTILISMART.** UTILITYAPI WILL NOT HAVE ANY LIABILITY OF ANY KIND TO CUSTOMER ARISING OUT OF OR RELATED TO THE GBT SERVICES, WHETHER IN CONTRACT, TORT (INCLUDING NEGLIGENCE), EQUITY OR UNDER ANY OTHER THEORY OF LIABILITY. TO THE EXTENT THAT THE FOREGOING EXCLUSION OF LIABILITY IS NOT ENFORCEABLE UNDER APPLICABLE LAW, THEN UTILITYAPI'S MAXIMUM AGGREGATE LIABILITY TO CUSTOMER ARISING OUT OF OR RELATED TO THE GBT SERVICES (WHETHER IN CONTRACT OR TORT OR UNDER ANY OTHER THEORY OF LIABILITY) SHALL NOT EXCEED CAN$ 1,000.

[Remainder of page intentionally left blank.]

utilismart™
CORPORATION

SERVICES AGREEMENT

AGREEMENT NUMBER: UCC-2019-02

THIS AGREEMENT made as of April 01, 2019 with an initial term start date of April 01, 2019 (the "**Initial Term Start Date**");

BETWEEN:

UTILISMART CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario and having an office at 201-555 Southdale Rd. East, London, Ontario N6E 1A2 (hereinafter, **"Utilismart"** or **"Company"**)

- and –

ESSEX POWERLINES CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario and having an office at 2730 Highway 3, Oldcastle Ontario N0R 1L0, (hereinafter, **"Customer"**)

1. SCHEDULES

a. The following Schedules attached hereto shall be deemed to form part of this Agreement as if specifically restated herein:

SCHEDULE A - SERVICES & FEES
SCHEDULE B - SERVICE LEVEL AND CUSTOMER SUPPORT

b. In the event of a conflict between the terms of any schedule and the terms in the main body of this Agreement, the terms of the main body of the Agreement shall govern.

2. SCOPE OF SERVICES

a. The Company shall provide, and the Customer shall pay for, the software term license and services outlined in SCHEDULE A (the "Services") in accordance with the terms and conditions herein.

b. The Company may modify the manner in which the Services are provided to the Customer during the Initial Term or Renewal Term (as such terms are defined in Section 6(a) below) provided that such modifications are consented to in writing by the Customer (said consent will not be unreasonably withheld).

3. PAYMENT

Upon being provided the Services from Utilismart, the Customer shall pay the Company the fees as set out in and in accordance with SCHEDULE A. The Customer shall pay all taxes and shall be separately itemized on the Customer's bill. Monthly invoices shall be sent to the Customer while the Services are being provided, unless a different payment schedule is agreed to in writing and set forth in SCHEDULE A. Invoices are payable to the Company thirty (30) days from the date of receipt of the invoice by the Customer. Interest charges will be added to any past due amounts at the rate of 1.5% per month (18% per annum).

4. CONFIDENTIAL INFORMATION

Each party agrees that it shall not disclose, either during the Initial Term or Renewal Term(s) (as such terms are defined in Section 6(a) below) or after the expiration or termination of this Agreement, to any unaffiliated third party any proprietary information of the other party, including, without limitation, customer information, information concerning trade secrets, methods, processes or procedures or any other confidential business or technical information or customer data ("Confidential Information"), which it learns during the course of its performance of this Agreement, without the prior written consent of the other party, except to the extent that any such Confidential Information: (i) is in the public domain; (ii) is independently developed by the receiving party; (iii) is already in the possession of such party prior to disclosure by the other party; (iv) is rightfully received from a third party not under a confidentiality obligation to the other party; or (v) is legally required to be disclosed by the receiving party. Either party may disclose Confidential Information to its sub-contractors, agents or advisors on a need-to-know basis, provided it first obtains an appropriate non-disclosure agreement therefrom. For greater certainty, however, the Company shall not disclose any identifiable, non-aggregated information related to the Customer's ratepayers, including but not limited to, names, addresses, phone numbers, meter numbers, etc.

5. NOTICES or COMMUNICATION

All notices, directions, authorizations and other communications of any nature required or permitted to be given hereunder by one party to the other (in each case, a "**Notice**") shall be in writing and shall be delivered personally or sent by courier or by facsimile or by electronic internet communication to the applicable addressee as follows (the "**Authorized Representative**"):

(a) in the case of the Customer:
Name: Joe Barile
Title: General Manager
Company: Essex Powerlines Corporation
Address (street): 2730 Highway 3
Address (City): Oldcastle Ontario N0R 1L0
Telephone: 1-226-252-6258
Email: jbarile@essexpowerlines.ca

(b) in the case of Utilismart
Name: John Avdoulos
Title: President
Company: Utilismart Corporation
Address (street): 201-555 Southdale Road East
Address (City): London, Ontario N6E 1A2
Telephone: 1-888-652-0689
Email: javdoulos@utilismartcorp.com

or at such other address the addressee may from time to time have notified the addressor pursuant to this Section 5. A Notice shall be deemed to have been sent and received on the day it is delivered personally or by courier or electronic internet communication. If such day is not a business day or if the Notice is received after 5:00 p.m., the Notice shall be deemed to have been sent and received on the next business day.

6. TERM AND TERMINATION

a. Initial and Renewal Terms. Subject to the early termination rights described in Sections 6(b) and 6(c) below, the term of this Agreement shall be 60 months, commencing on the date hereof (the "Initial Term"). The Agreement shall automatically be renewed for successive sixty (60) month term(s) (each a "Renewal Term"), unless 90 days' notice of termination is provided by the Customer to Utilismart Corporation in writing prior to the end of the Initial Term. The "Renewal Term" shall be for 12-month period following the "Initial Term" and shall continue until 90 days' notice of termination is provided by the Customer in writing to Utilismart Corporation prior to the end of the Renewal Term.

b. Termination for Breach**.** If there has been a breach or default of the terms of this Agreement (as defined below) by either party (the "Defaulting Party"), then the other party may terminate this Agreement after giving the Defaulting Party Notice, in accordance with the provisions of this Agreement, of the breach or default and 30 days to remedy the same or 10 business days in the case of a failure to make, when due, any payment pursuant to this Agreement. In the event the breach or default is not remedied with the time periods described above, this Agreement shall terminate immediately. For the purposes of this Agreement, a breach or default will include the following:

    (i) A violation of any term of this Agreement; and
    (ii) The failure to make, when due, any payment required pursuant to this Agreement.

c. Effect of Expiry or Termination. Subject to Sections 6(a) – (b), upon expiry or termination of this Agreement, the following shall apply:

    (1) Utilismart will immediately stop performing Services, unless otherwise agreed to in writing by the Customer;
    (2) The Customer will pay Utilismart any fees described in SCHEDULE A which have been invoiced by Utilismart and remain payable by the Customer under the terms of this Agreement for Services provided by Utilismart up to and including the date of termination;
    (3) The termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination and shall not affect any continuing obligations of either of the parties under this Agreement.

7. INTELLECTUAL PROPERTY RIGHTS

a. Customer Proprietary Information. The Company acknowledges and agrees that it shall have no right, title, claim, interest, security interest or lien ("Interest") in any specifications, designs, plans, drawings, data, software, computer systems, prototypes or other technical or business information ("Proprietary Information") and disclosed to the Company by or on behalf of the Customer in connection with this Agreement ("Customer Proprietary Information"), regardless of whether any such information constitutes a trade secret or is competitively sensitive, or in any Proprietary Rights (as defined below) with respect thereto, and disclaims any such Interest in any of the Customer Proprietary Information or such Proprietary Rights. The Customer hereby grants or shall grant to The Company a personal, non-exclusive, non-transferable, royalty-free license (without the right to sublicense, except to affiliates) during the Term, to use, execute, reproduce, display, perform and copy such Customer Proprietary Information (including the right to provide such information to subcontractors) for the sole purpose of performing the Services and only to the extent necessary to do so. As used in this Agreement, "Proprietary Rights" means, with respect to any item, all trade secret, copyright, patent,

trademark, service mark, certification mark, trade dress or other intellectual property or proprietary rights in all countries related to such item
or any part thereof, any extensions or renewals of the foregoing, and any registrations, patents or applications with respect to the foregoing.

b. The Company Proprietary Information. The Customer acknowledges and agrees that it shall have no Interests in any Proprietary Information disclosed to the Customer by or on behalf of the Company in connection with this Agreement ("The Company Proprietary Information"), regardless of whether any such information constitutes a trade secret or is competitively sensitive, or in any Proprietary Rights with respect thereto, and disclaims any such Interest that it might otherwise have in any of the Company Proprietary Information or such Proprietary Rights. Where necessary for the proper performance of the Services under this Agreement, the Company will grant to the Customer a personal, non-exclusive, non-transferable, royalty-free license (without the right to sublicense, except to affiliates) during the Term, to use, execute, display, perform and copy any such Company Proprietary Information for use solely in connection with Customer's receipt of the Services.

8. LIMITATIONS OF LIABILITY

a. Neither party shall be liable to the other party for any special, indirect, incidental, consequential or punitive damages of any character, including but not limited to loss of use, loss of profit, past and future, additional out-of-pocket expenses incurred by the other, or other claims resulting from, arising out of, in connection with or in anyway incidental to any act or omission of the other party related to the provisions of this Agreement, including without limitation, claims of third parties.

TO THE MAXIMUM EXTENT PERMITTED BY LAW, THE LIABILITY OF THE COMPANY TO THE CUSTOMER FOR ANY REASON AND UPON ANY CAUSE OF ACTION WHATSOEVER, WHETHER IN CONTRACT OR TORT, SHALL BE LIMITED TO THE AGGREGATE SUM OF ALL FEES PAID BY THE CUSTOMER UNDER THIS AGREEMENT IN RESPECT OF THE SERVICES PROVIDED BY THE COMPANY (EXCLUDING ALL FEES OR EXPENSES RELATING TO SERVICES NOT DIRECTLY PROVIDED BY THE COMPANY SUCH AS FEES RELATED TO THE RESELLING OF THIRD PARTY SERVICES) IN THE ONE (1) MONTH PERIOD PRIOR TO THE DAY ON WHICH THE CAUSE OF ACTION AROSE.

b. The Company shall not be liable for any costs, losses, damages, legal costs and expenses, liability, claims and demands resulting from or arising in connection with any use of the Customer's usernames or passwords. The Customer is responsible for ensuring that the usernames and passwords are kept confidential. While the Company agrees to take commercially reasonable measures to protect its systems, the Customer acknowledges and agrees that under no circumstances shall the Company be held responsible or liable for situations where the data stored or communicated through the Company's website interface are accessed by third parties through illegal or illicit means, including situations where such data is accessed through the exploitation of security gaps, weaknesses or flaws, if unknown to the Company at the time, which may exist in the Host System (as defined herein). The Company simply stores and facilitates the transmission of private electronic communications. Electronic communications on the Company's Host System are private, and only under situations where explicitly required or allowed by law will such communications be accessed, intercepted, disclosed, or used without the consent of at least one of the parties to the communication.

c. While the Company agrees to take commercially reasonable steps to ensure that the Services being provided by it under this Agreement will perform as represented to Customer in this Agreement, the Company does not represent or warrant that the Services will continuously operate or be provided without error or malfunction. The Customer agrees that in the event of an error, malfunction, or failure of the Services to perform as represented herein (an "Error"), the Company shall first be given a comprehensive written report from Customer as to the Errors being experienced in as much detail as reasonably possibly so as to assist Company in rectifying same. Company agrees to promptly review and to make commercially reasonable efforts to remedy the Error without delay. The parties shall cooperate so as to allow Company to effect any required changes, patches, updates, etc. in a timely manner and to minimize the disruption to Customer.

d. The parties agree that the Company shall have no liability for any of Customer's damages or losses arising as a result of an Error if: (i) the Company rectifies the Error within a reasonable period of time, (ii) the Customer fails to follow the error reporting procedure set out in this section, or (iii) the Error is caused by:

   (aa) any product or service, including but not limited to hardware, software or telecommunications services supplied by a third party, and/or including but not limited to all products and services which the Company offers to its Customer as a reseller but which are delivered by a third party entity (a "Third Party Service"); or

   (bb) any Error that is caused by or results from a Third Party Service; or

   (cc) any force majeure (being a strike, labour trouble, inability to get materials or services, power failure, restrictive governmental laws or regulations, riots, insurrection, sabotage, rebellion, war, act of God, or any other similar reason or cause) beyond the control of the Company.

Customer shall also take all commercially reasonable steps necessary so as to comply with the Company's advice and direction as to accessing and using the Services so as to reduce the likelihood of Errors.

9. GENERAL

a. Entire Agreement. This Agreement, together with the Schedules attached hereto, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all prior agreements, representations, warranties or other provisions, express or implied, collateral, statutory or otherwise, relating to the subject matter hereof except as herein provided.

b. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The parties irrevocably attorn to the jurisdiction of the courts of Ontario with respect to any matter arising under or related to this Agreement.

c. Amendments. This Agreement will not be amended or supplemented except by written agreement entered into by an authorized signatory of each of the parties.

d. Waivers. No waiver of any obligation or any remedy for breach of any provision of this Agreement will be effective or binding unless made in writing and agreed to by an authorized signatory of the party purporting to give the same and, unless otherwise provided, will be limited to the specific obligation or breach waived.

e. Independent Contractor. Nothing contained in this Agreement shall be construed to constitute either party as a partner, employee or agent of, or joint venture with the other party. Neither party shall have any authority to hold itself out as acting on behalf of or to legally bind the other.

f. Binding Agreement. This Agreement shall endure to the benefit of and shall be binding on and enforceable by the parties, and where the context so permits, their respective successors and permitted assigns. Except as otherwise set out in this Agreement, this Agreement shall not confer upon any other person except the parties and their respective successors and permitted assigns, any rights, interests, obligations or remedies under this Agreement.

g. Assignment. Utilismart may assign this Agreement or any of its rights or obligations hereunder, in whole or in part, with the prior written consent of the other party (said consent will not be unreasonably withheld).

h. Severability. In the event that any of the covenants herein shall be held unenforceable or declared invalid for any reason whatsoever, to the extent permitted by law, such unenforceability or invalidity shall not affect the enforceability or validity of the remaining provisions of this Agreement and such unenforceable or invalid portion shall be severable from the remainder of this Agreement.

i. Execution in Counterparts. This Agreement may be executed in counterparts and delivered by electronic means and the counterparts together shall constitute one and the same Agreement.

10. SURVIVAL

a. Neither the expiration of the Term nor the earlier termination of this Agreement will release either of the parties from any obligation or liability incurred prior to such expiration or termination.

b. In addition to the terms of this Agreement that by their very nature survive the expiry of termination of this Agreement, the terms of Article 4 (Confidential Information) Article 7 (Intellectual Property Rights) and Article 8 (Limitation of Liability) shall survive the expiration or earlier termination of this Agreement for a period of five (5) years.

[Remainder of page intentionally left blank. The next page is the execution page.]

[redacted]

[redacted]

[redacted]

[redacted]

utilismart
CORPORATION

SOFTWARE TERM LICENSE AND SERVICES AGREEMENT

AGREEMENT NUMBER: UCC-2018-14

THIS AGREEMENT made as of July 30, 2018 with an initial term start date of August 01, 2018 (the **"Initial Term Start Date"**);

BETWEEN:

UTILISMART CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario and having an office at 201-555 Southdale Rd. East, London, Ontario N6E 1A2 (hereinafter, **"Utilismart"** or **"Company"**)

- and –

ESSEX POWERLINES CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario and having an office at 2730 Highway 3, Oldcastle Ontario N0R 1L0, (hereinafter, **"Customer"**)

1. SCHEDULES

a. The following Schedules attached hereto shall be deemed to form part of this Agreement as if specifically restated herein:

SCHEDULE A - SOFTWARE TERM LICENSE, SERVICES & FEES
SCHEDULE B - SERVICE LEVEL AND CUSTOMER SUPPORT
SCHEDULE C - IMPLEMENTATION SCHEDULE

b. In the event of a conflict between the terms of any schedule and the terms in the main body of this Agreement, the terms of the main body of the Agreement shall govern.

2. SCOPE OF SERVICES

a. The Company shall provide, and the Customer shall pay for, the software term license and services outlined in SCHEDULE A (the "Services") in accordance with the terms and conditions herein.

b. The Company may modify the manner in which the Services are provided to the Customer during the Initial Term or Renewal Term (as such terms are defined in Section 6(a) below) provided that such modifications are consented to in writing by the Customer (said consent will not be unreasonably withheld).

3. PAYMENT

Upon being provided the Services from Utilismart, the Customer shall pay the Company the fees as set out in and in accordance with SCHEDULE A. The Customer shall pay all taxes and shall be separately itemized on the Customer's bill. Monthly invoices shall be sent to the Customer while the Services are being provided, unless a different payment schedule is agreed to in writing and set forth in SCHEDULE A. Invoices are payable to the Company thirty (30) days from the date of receipt of the invoice by the Customer. Interest charges will be added to any past due amounts at the rate of 1.5% per month (18% per annum).

4. CONFIDENTIAL INFORMATION

Each party agrees that it shall not disclose, either during the Initial Term or Renewal Term(s) (as such terms are defined in Section 6(a) below) or after the expiration or termination of this Agreement, to any unaffiliated third party any proprietary information of the other party, including, without limitation, customer information, information concerning trade secrets, methods, processes or procedures or any other confidential business or technical information or customer data ("Confidential Information"), which it learns during the course of its performance of this Agreement, without the prior written consent of the other party, except to the extent that any such Confidential Information: (i) is in the public domain; (ii) is independently developed by the receiving party; (iii) is already in the possession of such party prior to disclosure by the other party; (iv) is rightfully received from a third party not under a confidentiality obligation to the other party; or (v) is legally required to be disclosed by the receiving party. Either party may disclose Confidential Information to its sub-contractors, agents or advisors on a need-to-know basis, provided it first obtains an appropriate non-disclosure agreement therefrom. For greater certainty, however, the Company shall not disclose any identifiable, non-aggregated information related to the Customer's ratepayers, including but not limited to, names, addresses, phone numbers, meter numbers, etc.

5. NOTICES or COMMUNICATION

All notices, directions, authorizations and other communications of any nature required or permitted to be given hereunder by one party to the other (in each case, a "**Notice**") shall be in writing and shall be delivered personally or sent by courier or by facsimile or by electronic internet communication to the applicable addressee as follows (the "**Authorized Representative**"):

(a) in the case of the Customer:

Name:	Joe Barile
Title:	General Manager
Company:	Essex Powerlines Corporation
Address (street):	2730 Highway 3
Address (City):	Oldcastle Ontario N0R 1L0
Telephone:	1-226-252-6258
Email:	jbarile@essexpowerlines.ca

(b) in the case of Utilismart

Name:	John Avdoulos
Title:	President
Company:	Utilismart Corporation
Address (street):	201-555 Southdale Road East
Address (City):	London, Ontario N6E 1A2
Telephone:	1-888-652-0689
Email:	javdoulos@utilismartcorp.com

or at such other address the addressee may from time to time have notified the addressor pursuant to this Section 5. A Notice shall be deemed to have been sent and received on the day it is delivered personally or by courier or electronic internet communication. If such day is not a business day or if the Notice is received after 5:00 p.m., the Notice shall be deemed to have been sent and received on the next business day.

6. TERM AND TERMINATION

a. Initial and Renewal Terms. Subject to the early termination rights described in Sections 6(b) and 6(c) below, the term of this Agreement shall be 36 months, commencing on the date hereof (the "Initial Term"). The Agreement shall automatically be renewed for successive thirty six (36) month term(s) (each a "Renewal Term"), unless 90 days' notice of termination is provided by the Customer to Utilismart Corporation in writing prior to the end of the Initial Term. The "Renewal Term" shall be for 36-month period following the "Initial Term" and shall continue until 90 days' notice of termination is provided by the Customer in writing to Utilismart Corporation prior to the end of the Renewal Term.

b. Termination for Breach. If there has been a breach or default of the terms of this Agreement (as defined below) by either party (the "Defaulting Party"), then the other party may terminate this Agreement after giving the Defaulting Party Notice, in accordance with the provisions of this Agreement, of the breach or default and 30 days to remedy the same or 10 business days in the case of a failure to make, when due, any payment pursuant to this Agreement. In the event the breach or default is not remedied with the time periods described above, this Agreement shall terminate immediately. For the purposes of this Agreement, a breach or default will include the following:

(i) A violation of any term of this Agreement; and
(ii) The failure to make, when due, any payment required pursuant to this Agreement.

c. Effect of Expiry or Termination. Subject to Sections 6(a) – (b), upon expiry or termination of this Agreement, the following shall apply:

(1) Utilismart will immediately stop performing Services, unless otherwise agreed to in writing by the Customer;
(2) The Customer will pay Utilismart any fees described in SCHEDULE A which have been invoiced by Utilismart and remain payable by the Customer under the terms of this Agreement for Services provided by Utilismart up to and including the date of termination;
(3) The termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination and shall not affect any continuing obligations of either of the parties under this Agreement.

7. INTELLECTUAL PROPERTY RIGHTS

a. Customer Proprietary Information. The Company acknowledges and agrees that it shall have no right, title, claim, interest, security interest or lien ("Interest") in any specifications, designs, plans, drawings, data, software, computer systems, prototypes or other technical or business information ("Proprietary Information") and disclosed to the Company by or on behalf of the Customer in connection with this Agreement ("Customer Proprietary Information"), regardless of whether any such information constitutes a trade secret or is competitively sensitive, or in any Proprietary Rights (as defined below) with respect thereto, and disclaims any such Interest in any of the Customer Proprietary Information or such Proprietary Rights. The Customer hereby grants or shall grant to The Company a personal, non-exclusive, non-transferable, royalty-free license (without the right to sublicense, except to affiliates) during the Term, to use, execute, reproduce, display, perform and copy such Customer Proprietary Information (including the right to provide such information to subcontractors) for the sole purpose of performing the Services and only to the extent necessary to do so. As used in this Agreement, "Proprietary Rights" means, with respect to any item, all trade secret, copyright, patent, trademark, service mark, certification mark, trade dress or other intellectual property or proprietary rights in all countries related to such item or any part thereof, any extensions or renewals of the foregoing, and any registrations, patents or applications with respect to the foregoing.

b. The Company Proprietary Information. The Customer acknowledges and agrees that it shall have no Interests in any Proprietary Information disclosed to the Customer by or on behalf of the Company in connection with this Agreement ("The Company Proprietary Information"), regardless of whether any such information constitutes a trade secret or is competitively sensitive, or in any Proprietary Rights with respect thereto, and disclaims any such Interest that it might otherwise have in any of the Company Proprietary Information or such Proprietary Rights. Where necessary for the proper performance of the Services under this Agreement, the Company will grant to the Customer a personal, non-exclusive, non-transferable, royalty-free license (without the right to sublicense, except to affiliates) during the Term, to use, execute, display, perform and copy any such Company Proprietary Information for use solely in connection with Customer's receipt of the Services.

8. LIMITATIONS OF LIABILITY

a. Neither party shall be liable to the other party for any special, indirect, incidental, consequential or punitive damages of any character, including but not limited to loss of use, loss of profit, past and future, additional out-of-pocket expenses incurred by the other, or other claims resulting from, arising out of, in connection with or in anyway incidental to any act or omission of the other party related to the provisions of this Agreement, including without limitation, claims of third parties.

TO THE MAXIMUM EXTENT PERMITTED BY LAW, THE LIABILITY OF THE COMPANY TO THE CUSTOMER FOR ANY REASON AND UPON ANY CAUSE OF ACTION WHATSOEVER, WHETHER IN CONTRACT OR TORT, SHALL BE LIMITED TO THE AGGREGATE SUM OF ALL FEES PAID BY THE CUSTOMER UNDER THIS AGREEMENT IN RESPECT OF THE SERVICES PROVIDED BY THE COMPANY (EXCLUDING ALL FEES OR EXPENSES RELATING TO SERVICES NOT DIRECTLY PROVIDED BY THE COMPANY SUCH AS FEES RELATED TO THE RESELLING OF THIRD PARTY SERVICES) IN THE ONE (1) MONTH PERIOD PRIOR TO THE DAY ON WHICH THE CAUSE OF ACTION AROSE.

b. The Company shall not be liable for any costs, losses, damages, legal costs and expenses, liability, claims and demands resulting from or arising in connection with any use of the Customer's usernames or passwords. The Customer is responsible for ensuring that the usernames and passwords are kept confidential. While the Company agrees to take commercially reasonable measures to protect its systems, the Customer acknowledges and agrees that under no circumstances shall the Company be held responsible or liable for situations where the data stored or communicated through the Company's website interface are accessed by third parties through illegal or illicit means, including situations where such data is accessed through the exploitation of security gaps, weaknesses or flaws, if unknown to the Company at the time, which may exist in the Host System (as defined herein). The Company simply stores and facilitates the transmission of private electronic communications. Electronic communications on the Company's Host System are private, and only under situations where explicitly required or allowed by law will such communications be accessed, intercepted, disclosed, or used without the consent of at least one of the parties to the communication.

c. While the Company agrees to take commercially reasonable steps to ensure that the Services being provided by it under this Agreement will perform as represented to Customer in this Agreement, the Company does not represent or warrant that the Services will continuously operate or be provided without error or malfunction. The Customer agrees that in the event of an error, malfunction, or failure of the Services to perform as represented herein (an

"Error"), the Company shall first be given a comprehensive written report from Customer as to the Errors being experienced in as much detail as reasonably possibly so as to assist Company in rectifying same. Company agrees to promptly review and to make commercially reasonable efforts to remedy the Error without delay. The parties shall cooperate so as to allow Company to effect any required changes, patches, updates, etc. in a timely manner and to minimize the disruption to Customer.

d. The parties agree that the Company shall have no liability for any of Customer's damages or losses arising as a result of an Error if: (i) the Company rectifies the Error within a reasonable period of time, (ii) the Customer fails to follow the error reporting procedure set out in this section, or (iii) the Error is caused by:

(aa) any product or service, including but not limited to hardware, software or telecommunications services supplied by a third party, and/or including but not limited to all products and services which the Company offers to its Customer as a reseller but which are delivered by a third party entity (a "Third Party Service"); or

(bb) any Error that is caused by or results from a Third Party Service; or

(cc) any force majeure (being a strike, labour trouble, inability to get materials or services, power failure, restrictive governmental laws or regulations, riots, insurrection, sabotage, rebellion, war, act of God, or any other similar reason or cause) beyond the control of the Company.

Customer shall also take all commercially reasonable steps necessary so as to comply with the Company's advice and direction as to accessing and using the Services so as to reduce the likelihood of Errors.

9. GENERAL

a. Entire Agreement. This Agreement, together with the Schedules attached hereto, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all prior agreements, representations, warranties or other provisions, express or implied, collateral, statutory or otherwise, relating to the subject matter hereof except as herein provided.

b. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The parties irrevocably attorn to the jurisdiction of the courts of Ontario with respect to any matter arising under or related to this Agreement.

c. Amendments. This Agreement will not be amended or supplemented except by written agreement entered into by an authorized signatory of each of the parties.

d. Waivers. No waiver of any obligation or any remedy for breach of any provision of this Agreement will be effective or binding unless made in writing and agreed to by an authorized signatory of the party purporting to give the same and, unless otherwise provided, will be limited to the specific obligation or breach waived.

e. Independent Contractor. Nothing contained in this Agreement shall be construed to constitute either party as a partner, employee or agent of, or joint venture with the other party. Neither party shall have any authority to hold itself out as acting on behalf of or to legally bind the other.

f. Binding Agreement. This Agreement shall endure to the benefit of and shall be binding on and enforceable by the parties, and where the context so permits, their respective successors and permitted assigns. Except as otherwise set out in this Agreement, this Agreement shall not confer upon any other person except the parties and their respective successors and permitted assigns, any rights, interests, obligations or remedies under this Agreement.

g. Assignment. Utilismart may assign this Agreement or any of its rights or obligations hereunder, in whole or in part, with the prior written consent of the other party (said consent will not be unreasonably withheld).

h. Severability. In the event that any of the covenants herein shall be held unenforceable or declared invalid for any reason whatsoever, to the extent permitted by law, such unenforceability or invalidity shall not affect the enforceability or validity of the remaining provisions of this Agreement and such unenforceable or invalid portion shall be severable from the remainder of this Agreement.

i. Execution in Counterparts. This Agreement may be executed in counterparts and delivered by electronic means and the counterparts together shall constitute one and the same Agreement.

10. SURVIVAL

a. Neither the expiration of the Term nor the earlier termination of this Agreement will release either of the parties from any obligation or liability incurred prior to such expiration or termination.

b. In addition to the terms of this Agreement that by their very nature survive the expiry of termination of this Agreement, the terms of Article 4 (Confidential Information) Article 7 (Intellectual Property Rights) and Article 8 (Limitation of Liability) shall survive the expiration or earlier termination of this Agreement for a period of five (5) years.

[Remainder of page intentionally left blank. The next page is the execution page.]

[redacted]

[redacted]

SCHEDULE C – IMPLEMENTATION SCHEDULE

System / Service	Implementation Completion and System / Service Commissioning Date
RSVA Risk Manager	August 01, 2018

Implementation schedule and related system / service commissioning dates are subject to availability of the information required for the setup and integration, availability of the third-party resources, and detailed project plan.

[Remainder of page intentionally left blank.]

Attachment D- Job Descriptions

Position Title: Purchasing and Inventory Supervisor	**Date of Last Revision: June 28th, 2023**
Reports To: Manager of Corporate Services	**Previous Revision:**
Department: Stores	

Position Summary:

The Purchasing and Inventory Supervisor is responsible for procuring and managing the company's supply of products and services to ensure appropriate inventory levels are maintained and required services are obtained. The position will supervise the day-to-day operations of the Stores department and report to the Manager of Corporate Services. The incumbent manages purchases of material and services, invoicing, receiving and job inventory debits and credits. The position is responsible for controlling inventory to ensure material availability while working to continually improve departmental and process efficiencies.

Major Responsibilities:

1. Analyze inventory levels and identify purchasing requirements to ensure appropriate lead time.
2. Receive inventory to ensure it is consistent with the order and enter invoices into the system for payment.
3. Update pricing of goods in the accounting system to ensure costing and the value of inventory is accurate. Determine minimum order quantities for material and update information within inventory tracking software including Great Plains.
4. Issue purchase orders, process invoices and packing slips.
5. Ensure that all purchases, issues and credits are tracked and properly accounted for following commonly accepted accounting rules and as per EPL procedures.
6. Oversee scrap transformer program including documenting transformers that have been removed from service and sent to service provide for scrap metal costs,
7. Supervise and participate in the year-end inventory count and prepare required reports for internal stakeholders.
8. Review job schedules and ensure Operations has the required tools, materials and equipment to support project completion.
9. Participate in the tendering process and ensure pricing is reflected accurately for required materials.
10. Prepare and process customer insurance claims and respond to any inquiries from the insurance carrier.
11. Provide training and guidance as appropriate for a supervisory position.
12. Issue reports as requested from other departments as to the status of orders, issues with lead times or any other request relevant to the position and its impact on ongoing work.
13. Work with Manager of Corporate Services to assist in modernization of inventory control up to and including introduction of new software and/or processes.

14. Provide Job Closing analyses of all Capital, Recoverable and 3rd party jobs to ensure all required material has been charged to job prior to closing.
15. Substitute for the Manager of Corporate Services commensurate with the incumbent's level of training, experience and knowledge which may include fleet and facility maintenance scheduling.

Skills and Abilities:

- Advanced interpersonal skills and the ability to work with vendors and customers
- Advanced organizational and multi-tasking skills
- Advanced MS Office skills
- Basic financial management and accounting skills
- Ability to be available for overtime hours

Knowledge:

- Intermediate knowledge of purchasing and inventory systems
- Basic knowledge of Occupational Health and Safety requirements as it relates to individuals, the organization and operational requirements

Experience:

- Bachelor's in Business Administration
- Certified Purchasing Professional (CPP) an asset
- 3-5 years' experience in a purchasing position
- 2-4 years' experience in a supervisory role (in a Union environment would be an asset)
- Experience in a utility environment is an asset
- Class G license

Positions Supervised:

Storekeeper
Utility Person (shared with Supervisor of Operations on an as needed basis)

Note: This job description indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties, or responsibilities required of the incumbent. The incumbent may be asked to perform other duties which may be assigned from time to time.

Position Title: Distribution Systems Engineer	**Date of Last Revision: July 11, 2023**
Reports To: Director of Operations	**Previous Revision:**
Department: Operations	

Position Summary:

The Distribution Systems Engineer is responsible for overseeing and operating the SCADA system. The incumbent will grow, manage and maintain the system, ensuring its reliability and promoting its interconnection with other corporate systems to continuously improve performance aligned to operational needs.

The Distribution Systems Engineer liaises with the Control Room provider to monitor and coordinate with the team to ensure the efficient and safe operation of the power distribution network.

Major Responsibilities:

1. Monitor and coordinate with the control room operations team to ensure the efficient and safe operation of the power distribution network.
2. Act as the primary point of contact for control room operations and support the team during emergency situations such as power outages and severe weather events.
3. Manage the control room services contract, approve costs, negotiate changes and ensure adherence to all aspects of the contract.
4. Support the transition of control room services to a DSO model consistent with the company's strategy.
5. Ensure map data is maintained and synchronized across all platforms including GIS, SCADA and the Control Room.
6. Develop and implement strategies and perform regular maintenance tasks to ensure the SCADA system is operating at maximum efficiency and reliability.
7. Develop and maintain standard operating procedures for the SCADA system and provide training to team members as required.
8. Assist in the development of emergency response plans, policies and procedures and ensure that all stakeholders are provided with the requisite training and communication required.
9. Track and manage compliance with ESA regulations and update the Construction Verification program as required.
10. Support the planning, management and communication of outages in conjunction with Customer Service and the Control Room teams.
11. Maintain in-house expertise and provide training to various employee groups as required.

Skills and Abilities:

- Advanced project management skills and experience managing SCADA projects

- Excellent communication skills both written and verbal and the ability to communicate technical information to non-technical stakeholders
- Advanced problem solving and analytical skills with the ability to identify and resolve technical issues quickly
- Ability to work effectively in a team environment and build strong relationships and collaborate with stakeholders
- Ability to lead and manage a team of technical professionals
- Ability to respond quickly to emergency situations and work well under pressure
- Advanced MS Office skills

Knowledge:

- Advanced knowledge of SCADA hardware, software and communication protocols
- Strong knowledge of electric utility operations and power distribution systems
- Intermediate knowledge of the Utility Work Protection Code, IHSA Electrical Safety Rules, ESA Distribution Safety Regulations, Regulation 22/04, Conditions of Service, IESO Restoration requirements and all other applicable government regulations
- Intermediate knowledge of Occupational Health and Safety requirements as it relates to individuals, the organization and operational requirements

Experience:

- Bachelor's in Electrical Engineering or Project Management
- Professional Engineer or Project Management Professional (PMP) certification
- 3+ years' experience in SCADA system management, preferably in an electric utility environment
- Class G license

Positions Supervised:

n/a

Note: This job description indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties, or responsibilities required of the incumbent. The incumbent may be asked to perform other duties which may be assigned from time to time.

Incumbent's Signature: ______________________ **Date:** ______________

Supervisor's Signature: ______________________ **Date:** ______________

Cyber Security Supervisor

Job Responsibilities:

- Lead corporate cyber security governance and proactively implement security measures to protect corporate data, ensure customer privacy of information and secure the corporate computing environment.
- Identify cybersecurity risks and recommend remediation and/or mitigation methods.
- Participate in PIA/TRA engagements to identify and participate in the remediation of potential risks in the environment.
- Support of IT environments includes management of infrastructure and security system resources; risk management, security compliance, vulnerability scanning, patching, upgrades; measured against internal and external customer SLAs.
- Daily maintenance, control and enforcement of the cybersecurity fabric which may include firewalls, load balancers, switches, wireless, end points and other key products and solutions.
- Ensure compliance with the necessary governing bodies (OEB) security standards and frameworks.
- Contribute to the maintenance and development of corporate and partners security policies, procedures and standards
- Implement and maintain a third-party cybersecurity risk management program
- Responsible for auditing and monitoring compliance within established security policies, procedures and standards.
- Remain vigilant and knowledgeable in cybersecurity strategy, technology and training methods.
- Train and/or mentor other team members, peers and clients as appropriate.
- Develop/Maintain a cybersecurity training program.
- Participate in the validation and testing of system changes, track and enforce change control management.
- Participate in privacy & security incident investigations.
- Interface with management, clients and department heads on cybersecurity issues.
- Lead all cybersecurity projects.
- Conduct incident response and investigation and provide root-cause analysis for cybersecurity incidents.
- Contribute to the knowledge base, and provide recommendations for continuous improvements to workflow, process, resiliency, cost structure, and technology.
- Manage security vendor and partner relationships.
- Communicate technical subjects in plain language both orally and in writing.
- Oversee the development and maintenance of DRP and BCP
- Ensure tabletop exercises are performed annually

Skills and Abilities:

- Advanced problem solving and decision-making stills
- Advanced MS Office skills
- Advanced Time management skills
- Advanced oral and written communication skills
- Financial and budgeting skills

Knowledge:

- Expert knowledge of cyber security frameworks, including NIST and PCI DSS
- Advanced knowledge of Linux? and Windows operating systems on both virtualized and stand-alone environments
- Advanced knowledge of security appliance configuration and management
- Advanced knowledge of project management
- Knowledge of budgeting, planning and financial reporting

Requirements:

- 7+ years of cybersecurity experience
- Bachelor's Degree in Computer Science or equivalent, or:
    - Relevant cybersecurity certifications (CISSP, GIAC, CISM, CompTIA, ITIL, etc.)

Supervision

1 to 3 direct reports

Attachment E- EPLC’s 2023 T2 Return

200

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

Identification

Business number (BN) **001** 87006 6529 RC0001

Corporation's name
002 Essex Powerlines Corporation

Address of head office
Has this address changed since the last time the CRA was notified? . . . . **010** Yes ☐ No ☒
If **yes**, complete lines 011 to 018.
011 2730 Highway 3
012
City **015** Oldcastle
Province, territory, or state **016** ON
Country (other than Canada) **017**
Postal or ZIP code **018** N0R 1L0

Mailing address (if different from head office address)
Has this address changed since the last time the CRA was notified? . . . . **020** Yes ☐ No ☒
If **yes**, complete lines 021 to 028.
021 c/o
022 2730 Highway 3
023
City **025** Oldcastle
Province, territory, or state **026** ON
Country (other than Canada) **027**
Postal or ZIP code **028** N0R 1L0

Location of books and records (if different from head office address)
Has this address changed since the last time the CRA was notified? . . . . **030** Yes ☐ No ☒
If **yes**, complete lines 031 to 038.
031
032
City **035**
Province, territory, or state **036**
Country (other than Canada) **037**
Postal or ZIP code **038**

040 **Type of corporation at the end of the tax year** (tick one)
- ☒ 1 Canadian-controlled private corporation (CCPC)
- ☐ 2 Other private corporation
- ☐ 3 Public corporation
- ☐ 4 Corporation controlled by a public corporation
- ☐ 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** Year Month Day

To which tax year does this return apply?
Tax year start **060** Year Month Day 2023-01-01
Tax year-end **061** Year Month Day 2023-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . **063** Yes ☐ No ☒
If **yes**, provide the date control was acquired . . . . **065** Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . **066** Yes ☐ No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** Yes ☐ No ☒

Is this the first year of filing after:
Incorporation? . . . . **070** Yes ☐ No ☒
Amalgamation? . . . . **071** Yes ☐ No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** Yes ☐ No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** Yes ☐ No ☒

Is this the final return up to dissolution? . . . . **078** Yes ☐ No ☒

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada? **080** Yes ☒ No ☐
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** Yes ☐ No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- ☐ 1 Exempt under paragraph 149(1)(e) or (l)
- ☐ 2 Exempt under paragraph 149(1)(j)
- ☐ 4 Exempt under other paragraphs of section 149

Do not use this area
095 **096** **898**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	☒	9
Is the corporation an associated CCPC?	160	☒	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161	☐	49
Does the corporation have any non-resident shareholders who own voting shares?	151	☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162	☐	11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163	☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	☒	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	☐	15
Is the corporation claiming a loss or deduction from a tax shelter?	166	☐	T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167	☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168	☐	22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169	☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170	☐	29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171	☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172	☐	
Does the corporation earn income from one or more Internet web pages or websites?	180	☐	88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	☒	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	☐	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	☒	3
Is the corporation claiming any type of losses?	204	☒	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	☒	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	☐	6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	208	☒	8
Does the corporation have any resource-related deductions?	212	☐	12
Is the corporation claiming deductible reserves?	213	☐	13
Is the corporation claiming a patronage dividend deduction?	216	☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	217	☐	17
Is the corporation an investment corporation or a mutual fund corporation?	218	☐	18
Is the corporation carrying on business in Canada as a non-resident corporation?	220	☐	20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221	☐	21
Does the corporation have any Canadian manufacturing and processing profits or zero-emission technology manufacturing profits?	227	☐	27
Is the corporation claiming an investment tax credit?	231	☒	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	☐	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	☒	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	☒	
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238	☐	38
Is the corporation claiming a Part I tax credit?	242	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244	☐	45
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250	☐	39
Is the corporation claiming a Canadian film or video production tax credit?	253	☐	T1131
Is the corporation claiming a film or video production services tax credit?	254	☐	T1177
Is the corporation claiming a Canadian journalism labour tax credit?	272	☐	58
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255	☐	92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271	☐	T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	☒	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	☒	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	☐	54
Is the corporation claiming a return of fuel charge proceeds to farmers tax credit?	273	☐	63
Are you an employer reporting a non-qualified security agreement under subsection 110(1.9)?	274	☐	59
Is the corporation claiming an air quality improvement tax credit?	275	☐	65
Is the corporation subject to the additional 1.5% tax on banks and life insurers?	276	☐	68
Is the corporation a covered entity that redeemed, acquired or cancelled equity of the corporation in the tax year?	277	☐	56

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	Yes ☒	No ☐
Is the corporation inactive?	280	Yes ☐	No ☒
Did the corporation meet the definition of substantive CCPC under subsection 248(1) at any time during the tax year?	290	Yes ☐	No ☒

What is the corporation's main revenue-generating business activity? 913910 Other Local, Municipal and Regional Public Administration

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	LDC - BILL & COLLECT	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	Yes ☐	No ☒
Did the corporation emigrate from Canada during the tax year?	292	Yes ☐	No ☒
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	Yes ☐	No ☐
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	Year Month Day	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	Yes ☐	No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300		-1,731,849	A
Deduct:				
Charitable donations from Schedule 2	311			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine made before March 22, 2017, from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Employer deduction for non-qualified securities	352			
Subtotal			▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360			
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7 . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . **410** 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction for tax years starting before April 7, 2022

Amount C 500,000 x **415** *** 223,796 D = ... ______ E1
11,250

Taxable capital business limit reduction for tax years starting after April 6, 2022

Amount C 500,000 x **415** *** 223,796 D = ... 1,243,311 E2
90,000

Amount E1 or amount E2, whichever applies 1,243,311 ▶ 1,243,311 E3

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** . **417** ______ – 50,000 = . . ______ F

Amount C 500,000 x Amount F ______ = ... ______ G
100,000

The greater of amount E3 and amount G **422** 1,243,311 H

Reduced business limit (amount C **minus** amount H) (if negative, enter "0") . . . . **426** ______ I

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . ______ J

Reduced business limit after assignment (amount I **minus** amount J) . . . . **428** ______ K

Small business deduction – Amount A, B, C, or K, whichever is the least . . . . ______ x 19 % = **430** ______

Enter amount from line 430 at amount K on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations for each tax year that ended in the preceding calendar year. Each corporation with such income has to file a Schedule 7. For a corporation's first tax year that starts after 2018, this amount is reported at line 744 of the corresponding Schedule 7. Otherwise, this amount is the total of all amounts reported at line 745 of the corresponding Schedule 7 of the corporation for each tax year that ended in the preceding calendar year.

Small business deduction (continued)

Specified corporate income and assignment under subsection 125(3.2)

	L1 Name of corporation receiving the income and assigned amount	L Business number of the corporation receiving the assigned amount **490**	M Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column L [3] **500**	N Business limit assigned to corporation identified in column L [4] **505**
1.				

Total **510** ______ Total **515** ______

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income (other than specified farming or fishing income of the corporation for the year) from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column M in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 426.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Taxable income from line 360 on page 3 . . . . ______ A

Lesser of amounts 9B and 9H from Part 9 of Schedule 27 . . . . . . ______ B

Amount 13K from Part 13 of Schedule 27 . . . . . . ______ C

Personal services business income . . . . . . **432** ______ D

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least* . . . . . . ______ E

Aggregate investment income from line 440 on page 6** . . . . . . ______ F

Subtotal (**add** amounts B to F) ______ ▶ ______ G

Amount A **minus** amount G (if negative, enter "0") . . . . . . ______ H

General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 % . . . . . . ______ I

Enter amount I on line 638 on page 8.

* This is not applicable to substantive CCPCs.

** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, a substantive CCPC, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3 . . . . ______ J

Lesser of amounts 9B and 9H from Part 9 of Schedule 27 . . . . . . ______ K

Amount 13K from Part 13 of Schedule 27 . . . . . . ______ L

Personal services business income . . . . . . **434** ______ M

Subtotal (**add** amounts K to M) ______ ▶ ______ N

Amount J **minus** amount N (if negative, enter "0") . . . . . . ______ O

General tax reduction – Amount O **multiplied** by 13 % . . . . . . ______ P

Enter amount P on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Aggregate investment income from Schedule 7 . . . . **440** x 30 2 / 3 % = ... A

Foreign non-business income tax credit from line 632 on page 8 . . . . B

Foreign investment income from Schedule 7 . . . . **445** x 8 % = C

Subtotal (amount B **minus** amount C) (if negative, enter "0") ▶ D

Amount A **minus** amount D (if negative, enter "0") . . . . E

Taxable income from line 360 on page 3 . . . . F

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least* . . . . G

Foreign non-business income tax credit from line 632 on page 8 . . . . x 75 / 29 = H

Foreign business income tax credit from line 636 on page 8 . . x 4 = I

Subtotal (**add** amounts G to I) ▶ J

Subtotal (amount F **minus** amount J) K x 30 2 / 3 % = L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** N

* This is not applicable to substantive CCPCs. . . . .

Refundable dividend tax on hand

Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (line 530 of the preceding tax year)			520		A
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (line 545 of the preceding tax year) (if negative, enter "0")			535		B
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)		C			
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)		D			
Subtotal (amount C **plus** amount D)		▶			E
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary			525		F
ERDTOH dividend refund for the previous tax year			570		G
Refundable portion of Part I tax (from line 450 on page 6)					H
Part IV tax before deductions (amount 2A from Schedule 3)		I			
Part IV tax allocated to ERDTOH (amount E)		J			
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)		K			
Subtotal (amount I **minus** total of amounts J and K)		▶			L
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary			540		M
NERDTOH dividend refund for the previous tax year			575		N
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)					O
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount L **minus** amount O) (if negative enter “0”)					P
NERDTOH at the end of the tax year (total of amounts B, H, M, and P **minus** amount N) (if negative, enter "0")			545		
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount E **minus** the amount, if any, by which amount O exceeds amount L) (if negative, enter "0")					Q
ERDTOH at the end of the tax year (total of amounts A, F, and Q **minus** amount G) (if negative, enter "0")			530		

Dividend refund

38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)		AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)	421,667	DD
NERDTOH balance at the end of the tax year (line 545)		EE
Non-eligible dividend refund (amount DD or EE, whichever is less)		FF
Amount DD **minus** amount EE (if negative, enter "0")	421,667	GG
Amount BB **minus** amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund – Amount CC **plus** amount FF **plus** amount II		JJ

Enter amount JJ on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income (from line 360 on page 3) **multiplied** by 38 % . . . . **550** ______ A

Additional tax on personal services business income (section 123.5)

Taxable income from a personal services business . . . . **555** ______ x 5 % = **560** ______ B

Additional tax on banks and life insurers from Schedule 68 . . . . **565** ______ C

Recapture of investment tax credit from Schedule 31 . . . . **602** ______ D

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) or substantive CCPC's investment income (if it was a CCPC throughout the tax year or a substantive CCPC at any time in the tax year)

Aggregate investment income from line 440 on page 6 . . . . ______ E

Taxable income from line 360 on page 3 . . . . ______ F

Deduct:

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least* . . . . ______ G

Net amount (amount F **minus** amount G) ______ ► ______ H

Refundable tax on CCPC's or substantive CCPC's investment income – 10 2 / 3 % of whichever is less: amount E or amount H . . . . **604** ______ I

Subtotal (**add** amounts A, B, C, D, and I) ______ J

Deduct:

Small business deduction from line 430 on page 4 . . . . ______ K

Federal tax abatement . . . . **608** ______

Manufacturing and processing profits deduction and zero-emission technology manufacturing deduction from Schedule 27 . . . . **616** ______

Investment corporation deduction . . . . **620** ______

Taxed capital gains **624** ______

Federal foreign non-business income tax credit from Schedule 21 . . . . **632** ______

Federal foreign business income tax credit from Schedule 21 . . . . **636** ______

General tax reduction for CCPCs from amount I on page 5 . . . . **638** ______

General tax reduction from amount P on page 5 . . . . **639** ______

Federal logging tax credit from Schedule 21 . . . . **640** ______

Eligible Canadian bank deduction under section 125.21 . . . . **641** ______

Federal qualifying environmental trust tax credit . . . . **648** ______

Investment tax credit from Schedule 31 . . . . **652** ______

Subtotal ______ ► ______ L

Part I tax payable – Amount J **minus** amount L . . . . ______ M

Enter amount M on line 700 on page 9.

* This is not applicable to substantive CCPCs.

Privacy notice

Personal information (including the SIN) is collected to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Information about Programs and Information Holdings at **canada.ca/cra-information-about-programs**.

Summary of tax and credits

Federal tax

Part I tax payable from amount M on page 8			700		
Part II.2 tax payable from Schedule 56			705		
Part III.1 tax payable from Schedule 55			710		
Part IV tax payable from Schedule 3			712		
Part IV.1 tax payable from Schedule 43			716		
Part VI tax payable from Schedule 38			720		
Part VI.1 tax payable from Schedule 43			724		
Part VI.2 tax payable from Schedule 67			725		
Part XIII.1 tax payable from Schedule 92			727		
Part XIV tax payable from Schedule 20			728		
Total federal tax					

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)			760	50,335	
Total tax payable			770	50,335	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780				
Dividend refund from amount JJ on page 7	784				
Federal capital gains refund from Schedule 18	788				
Federal qualifying environmental trust tax credit refund	792				
Return of fuel charge proceeds to farmers tax credit from Schedule 63	795				
Canadian film or video production tax credit (Form T1131)	796				
Film or video production services tax credit (Form T1177)	797				
Canadian journalism labour tax credit from Schedule 58	798				
Air quality improvement tax credit from Schedule 65	799				
Tax withheld at source	800				
Total payments on which tax has been withheld 801					
Provincial and territorial capital gains refund from Schedule 18	808				
Provincial and territorial refundable tax credits from Schedule 5	812				
Tax instalments paid	840	78,576			
Total credits	890	78,576	▶	78,576	B
Balance (amount A **minus** amount B)				-28,241	

If the result is negative, you have **a refund**. If the result is positive, you have a **balance owing**.
Enter the amount below on whichever line applies.

Generally, the CRA does not charge or refund a difference of $2 or less.

Refund code 894 2

Refund 28,241

Balance owing

For information on how to enrol for direct deposit, go to **canada.ca/cra-direct-deposit**.

For information on how to make your payment, go to **canada.ca/payments**.

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 Yes ☐ No ☒

If this return was prepared by a tax preparer for a fee, provide their: EFILE number 920 C5622

RepID 925

Certification

I, 950 Richard (Last name) 951 Wayne (First name) 954 General Manager (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2024-06-21 — Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (519) 737-9811 — Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 Yes ☐ No ☒

958 Grace Flood — Name of other authorized person

959 (519) 737-9811 — Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Financial Statements of

ESSEX POWERLINES CORPORATION

And Independent Auditor's Report thereon

Year ended December 31, 2023
(Expressed in thousands of dollars)

KPMG LLP
618 Greenwood Centre
3200 Deziel Drive
Windsor, ON N8W 5K8
Canada
Telephone 519 251 3500
Fax 519 251 3530

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Essex Powerlines Corporation

Opinion

We have audited the financial statements of Essex Powerlines Corporation (the "Entity"), which comprise:

- the statement of financial position as at December 31, 2023
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2023, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditors' Responsibilities for the Audit of the Financial Statements"*** section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled are other ethical responsibilities in accordance with these requirements.

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

Responsibilities of Management and Those Charged with Governance for the Financial Statements

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

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

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

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Windsor, Canada
April 18, 2024

ESSEX POWERLINES CORPORATION

Statement of Financial Position

As at December 31, 2023, with comparative information for 2022

(in thousands of dollars)

	Note	2023	2022
Assets			
Current assets			
Cash and cash equivalents		$ 839	$ 1
Accounts receivable	4	6,795	6,207
Unbilled revenue		6,627	6,657
Income taxes receivable	8	384	644
Materials and supplies	5	1,691	1,197
Prepaid expenses		329	301
Total current assets		16,665	15,007
Non-current assets			
Property, plant and equipment	6	78,808	72,417
Intangible assets	7	1,922	1,111
Total non-current assets		80,730	73,528
Total assets		97,395	88,535
Regulatory balances	9	8,814	11,605
Total assets and regulatory balances		$ 106,209	$ 100,140

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Financial Position
As at December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Note	2023	2022
Liabilities			
Current liabilities			
Bank indebtedness		$ –	$ 3,221
Accounts payable and accrued liabilities	10	11,601	10,132
Long-term debt due within one year	11	3,420	2,512
Customer deposits		1,903	1,436
Dividend payable		1,100	1,084
Total current liabilities		18,024	18,385
Non-current liabilities			
Long-term debt	11	35,329	34,010
Post-employment benefits	12	2,115	2,185
Deferred revenue		11,634	8,595
Deferred tax liabilities	8	3,681	3,156
Total non-current liabilities		52,759	47,946
Total liabilities		70,783	66,331
Equity			
Share capital	13	15,773	15,773
Retained earnings		14,291	13,793
Accumulated other comprehensive income		1,840	1,804
Total equity		31,904	31,370
Total liabilities and equity		102,687	97,701
Regulatory balances	9	3,522	2,439
Total liabilities, equity and regulatory balances		$ 106,209	$ 100,140

See accompanying notes to the financial statements.

On behalf of the Board:

Michael D Prue Director

Director

ESSEX POWERLINES CORPORATION

Statement of Comprehensive Income
Year ended December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Note	2023	2022
Revenue			
Sale of energy		$ 67,435	$ 69,709
Distribution revenue		17,589	17,616
Solar generation		24	25
Other		1,260	1,193
	14	86,308	88,543
Operating expenses			
Cost of power purchased		66,326	71,029
Operating expenses	15	9,172	8,697
Solar expenses		6	7
Depreciation and amortization		3,615	3,285
Research and development SR&ED ITC reversed		–	19
		79,119	83,037
Income from operating activities		7,189	5,506
Net finance costs	16	(1,228)	(1,168)
Income before income taxes		5,961	4,338
Current tax expense	8	(23)	3
Deferred tax expense	8	512	591
Net income for the year		5,472	3,744
Net movement in regulatory balances, net of tax	9	(3,874)	(1,785)
Net income for the year and net movement in regulatory balances		1,598	1,959
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurements of post-employment benefits	12	49	434
Tax on re-measurements		(13)	(115)
Other comprehensive income for the year		36	319
Total comprehensive income for the year		$ 1,634	$ 2,278

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Changes in Equity
Year ended December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Share capital	Solar Equity	Retained earnings	Accumulated other comprehensive income (Loss)	Total
Balance at January 1, 2022	$ 15,773	$ –	$ 13,251	$ 1,485	$ 30,509
Net income and net movement in regulatory balances	–	–	1,959	–	1,959
Other comprehensive income	–	–	–	319	319
Prior period adjustment	–	–	(333)	–	(333)
Dividends	–	–	(1,084)	–	(1,084)
Balance at December 31, 2022	$ 15,773	$ –	$ 13,793	$ 1,804	$ 31,370
Balance at January 1, 2023	$ 15,773	$ –	$ 13,793	$ 1,804	$ 31,370
Net income and net movement in regulatory balances	–	–	1,598	–	1,598
Other comprehensive income	–	–	–	36	36
Dividends	–	–	(1,100)	–	(1,100)
Balance at December 31, 2023	$ 15,773	$ –	$ 14,291	$ 1,840	$ 31,904

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Cash Flows

Year ended December 31, 2023, with comparative information for 2022

(in thousands of dollars)

	2023	2022
Operating activities		
Net Income and net movement in regulatory balances	$ 1,598	$ 1,959
Adjustments for:		
Depreciation and amortization	3,615	3,285
Amortization of deferred revenue	(273)	(221)
Post-employment benefits	(21)	(55)
Net finance costs	1,228	1,168
Income tax expense	489	594
	6,636	6,730
Change in non-cash operating working capital:		
Accounts receivable	(588)	(756)
Unbilled revenue	30	(946)
Materials and supplies	(494)	(243)
Customer deposits	467	178
Prepaid expenses	(28)	(169)
Accounts payable and accrued liabilities	1,469	(45)
	856	(1,981)
Net movement in regulatory balances	3,874	1,785
Income tax received (paid)	283	(879)
Interest paid	(1,259)	(1,185)
Interest received	31	17
Net cash from operating activities	10,421	4,487
Investing activities		
Purchase of property, plant and equipment	(9,673)	(7,123)
Purchase of intangible assets	(1,196)	(415)
Proceeds on disposal of property, plant and equipment	52	69
Contributions received from customers	3,312	1,634
Net cash used by investing activities	(7,505)	(5,835)
Financing activities		
Dividends paid	(1,084)	(1,068)
Proceeds from long-term debt	4,000	–
Repayment of long-term debt	(1,773)	(1,724)
Net cash from (used by) financing activities	1,143	(2,792)
Change in cash, cash equivalents and bank indebtedness	4,059	(4,140)
Cash and cash equivalents and bank indebtedness, beginning of year	(3,220)	920
Cash, cash equivalents and bank indebtedness, end of year	$ 839	$ (3,220)

See accompanying notes to the financial statements.

1. Reporting entity:

Essex Powerlines Corporation (the “Corporation”) is a rate regulated, municipally owned local distribution company (”LDC”) which is wholly owned by Essex Power Corporation, which in turn, is wholly owned by the shareholders of Essex Power Corporation including the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The Corporation was incorporated on April 18, 2000 under the *Business Corporations Act* (Ontario), in accordance with the *Electricity Act*. The Corporation is located in Oldcastle, Ontario. The address of the Corporation’s registered office is 2730 Highway 3, Oldcastle, ON N0R 1L0.

The Corporation delivers electricity and related energy services to residential and commercial customers in Amherstburg, LaSalle, Leamington and Tecumseh, under a license issued by the Ontario Energy Board (“OEB”). The Corporation is regulated by the OEB and adjustments to the Corporation’s distribution and power rates require OEB approval.

The financial statements are for the Corporation as at and for the year ended December 31, 2023.

2. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with IFRS Accounting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 18, 2024.

(b) Basis of measurement:

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

(d) Use of estimates and judgments:

(i) Assumptions and estimation uncertainty:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

2. Basis of presentation (continued):

(d) Use of estimates and judgments (continued):

(i) Assumptions and estimation uncertainty (continued):

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

a) Notes 3 (d), (e), (f), 6, 7 – estimation of useful lives of its property, plant and equipment and intangible assets and related impairment tests on long-lived assets

b) Notes 3 (h), 9 – recognition and measurement of regulatory balances

c) Notes 3 (i), 12 – measurement of defined benefit obligations: key actuarial assumptions

d) Note 17 – recognition and measurement of provisions and contingencies

(ii) Judgments:

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following note:

a) Note 3 (j) – leases: whether an arrangement contains a lease

b) Note 3 (b) – determination of the performance obligation for contributions from customers and the related amortization period

c) Notes 3(h), 9 – recognition of regulatory balances

(e) Rate regulation:

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies, such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The OEB has a decision and order in place banning LDC's in Ontario from disconnecting homes for non-payment during the winter. This ban is normally in place from November 15 to April 30 each year.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

Rate setting

(i) Distribution Rates:

The Corporation files a "Cost of Service" ("COS") rate application every five years, unless approved for a deferral, under which the OEB establishes the revenues required to recover the forecasted operating costs, including amortization and income taxes, of providing the regulated electricity distribution service and providing a fair return on the Corporation's rate base. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and any registered interveners. Rates are approved based upon the review of evidence and information, including any revisions resulting from that review.

In the intervening years, an Incentive Regulation Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor set by the OEB and a "stretch factor" determined by the relative efficiency of an electricity distributor.

On August 28, 2017, the Corporation submitted a COS rate application to the OEB to change distribution rates effective May 1, 2018. The application was approved by the OEB on October 10, 2018.

On November 1, 2022, the Corporation submitted an IRM Application to the OEB requesting approval to change distribution rates effective May 1, 2023. The IRM Application, which provided a mechanistic and formulaic adjustment to distribution rates and charges, was approved by the OEB on March 23, 2023. The GDP IPI-FDD for 2024 is 3.70%, the Corporation's stretch factor is 0.15% and the productivity factor determined by the OEB is 0%, resulting in a net adjustment of 3.55% to the previous year's rates.

(ii) Electricity Rates:

The OEB sets Ontario electricity prices for low-volume consumers annually each year in November based on an estimate of how much it will cost to supply the province with electricity for the next year. In 2017, the OEB set new lower Regulated Price Plan (RPP) prices established under the *Ontario Fair Hydro Act, 2017*.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

(ii) Electricity Rates (continued):

On May 9, 2019, the Government of Ontario enacted Bill 87, the *Fixing the Hydro Mess Act*, *2019*. The legislation amended the *Ontario Rebate for Electricity Consumers Act, 2016* and the *Ontario Fair Hydro Plan Act, 2017.* Effective November 1, 2019, the OEB set electricity prices under the RPP based on the estimated cost to supply the province with electricity. The Ministry of Energy, Northern Development and Mines set the amount of the rebate under the *Ontario Rebate for Electricity Consumers Act, 2016* such that the monthly bill for a typical customer increased by the rate of inflation.

All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

(iii) Retail Transmission Rates:

These are the costs of delivering electricity from generating stations across the Province to local distribution networks. These charges include the costs to build and maintain the transmission lines, towers and poles and operate provincial transmission systems. Retail transmission rates are passed through to the operators of transmission networks and facilities.

(iv) Wholesale Market Service Rates:

These are the costs of administering the wholesale electricity system and maintaining the reliability of the provincial grid and include the costs associated with funding Ministry of Energy conservation and renewable energy programs. The Corporation is billed for the cost of the wholesale electricity system by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

3. Material accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

In addition, the Corporation adopted Disclosure of *Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2)* from January 1, 2023. The amendments require the disclosure of “material”, rather than “significant”, accounting policies. Although the amendment did not result in a change to the accounting policies themselves, they impacted the accounting policy information disclosed in Note 3 in certain instances.

(a) Financial instruments:

All financial assets and all financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(f).

The Corporation does not enter into derivative instruments. Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents may include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition:

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

3. Material accounting policies (continued):

(b) Revenue recognition (continued):

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants and the related performance incentive payments under Conservation and Demand Management (“CDM”) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies:

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

3. Material accounting policies (continued):

(d) Property, plant and equipment:

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the date of transition to IFRS, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of nine months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

	Years
Buildings	50
Distribution equipment	15 – 50
Computer hardware and equipment	5 – 10
Office equipment	10
Utility equipment and trucks	7 – 10
Solar generation	20

3. Material accounting policies (continued):

(e) Intangible assets:

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the date of transition to IFRS, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

	Years
Computer software	5
Land rights	50

(f) Impairment:

(i) Financial assets measured at amortized cost:

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

3. Material accounting policies (continued):

(f) Impairment (continued):

(ii) Non-financial assets (continued) :

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorated basis, if applicable.

An impairment loss in respect of goodwill is not reversed. For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

For the regulated business, the carrying costs of most of the Corporation's non-financial assets are included in rate base (the aggregate of approved investment in PP&E and intangible assets, excluding construction in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital) where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

(g) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills and deposits. Interest is paid on customer deposits. Deposits are also received for planned chargeable work. No interest is paid on these deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

3. Material accounting policies (continued):

(h) Regulatory balances:

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of recognizing regulatory balances in accordance with its previous Generally Accepted Accounting Principles (“GAAP”) when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. IFRS 14 is effective for periods beginning on or after January 1, 2016, however, early application was permitted. The Corporation elected to apply this Standard in its first IFRS financial statements as at December 31, 2015.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or other comprehensive income (“OCI”). When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the amounts are returned to the customer at rates approved by the OEB the amounts are recognized as a reduction of revenue.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

3. Material accounting policies (continued):

(i) Post-employment benefits:

(i) Pension plan:

The Corporation provides a pension plan for some of its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards and public utilities. OMERS is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by investment earnings. To the extent that the plan finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension:

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management’s best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(j) Leased assets:

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

3. Material accounting policies (continued):

(j) Leased assets (continued):

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

3. Significant accounting policies (continued):

(k) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the “Tax Acts”). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (“OEFC”). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Payments in lieu of taxes and payments under the Tax Acts are collectively referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

3. Significant accounting policies (continued):

(l) Accounting standards issued but not yet effective:

The following standards which are not yet effective for the year ended December 31, 2023, have not been applied in preparing these financial statements.

(i) Classification of Liabilities as Current or Non-Current (Amendments to IAS 1)

On January 23, 2020, the IASB issued amendments to IAS 1 *Presentation of Financial Statements*, to clarify the classification of liabilities as current or non-current.

On October 31, 2022, the IASB issued *Non-current Liabilities with Covenants (Amendments to IAS 1)* (the 2022 amendments), to improve the information a company provides about long-term debt with covenants.

The 2020 amendments and the 2022 amendments (collectively “the Amendments”) are effective for annual periods beginning on or after January 1, 2024.

(ii) Lease Liability in a Sale and Leaseback (Amendments to IFRS 16 Leases)

On September 22, 2022, the IASB issued *Lease Liability in a Sale and Leaseback (Amendments to IFRS 16).*

The amendments are effective for annual periods beginning on or after January 1, 2024.

(iii) Supplier Finance Arrangements (Amendments to IAS 7 and IFRS 7)

On May 25, 2023, the IASB issued amendments to IAS 7 *Statement of Cash Flows* and IFRS 7 *Financial Instruments: Disclosures.*

The amendments are effective for annual periods beginning on or after January 1, 2024.

(iv) Lack of exchangeability (Amendments to IAS 21)

On August 15, 2023, the IASB issued amendments to IAS 21 *The Effects of Changes in Foreign Exchange Rates* to clarify when a currency is exchangeable into another currency and how a company estimates a spot rate when a currency lacks exchangeability.

The amendments apply for annual reporting periods beginning on or after January 1, 2025, with earlier application permitted.

The Corporation has assessed the potential impacts on its financial statements, and determined that the future pronouncements will not have a material impact on the Corporation.

4. Accounts receivable:

	2023	2022
Trade receivables	$ 6,222	$ 5,650
Due from related parties	115	81
Other receivables	624	552
Billable work	65	49
Less:		
Loss allowance	(231)	(125)
	$ 6,795	$ 6,207

5. Materials and supplies:

Amount written down due to obsolescence in 2023 was $nil (2022 - $nil).

6. Property, plant and equipment:

	Land and buildings	Distribution equipment	Other fixed assets	Construction in-Progress	Total
Cost					
Balance at January 1, 2023	$ 3,223	$ 82,342	$ 6,380	$ 626	$ 92,571
Additions	730	7,976	1,091	–	9,797
Disposals/retirements	(20)	(70)	(77)	–	(167)
Balance at December 31, 2023	$ 3,933	$ 90,248	$ 7,394	$ 626	$ 102,201
Balance at January 1, 2022	$ 2,998	$ 76,444	$ 5,658	$ 640	$ 85,740
Additions	225	5,989	799	110	7,123
Disposals/retirements	–	(91)	(77)	–	(168)
Balance at December 31, 2022	$ 3,223	$ 82,342	$ 6,380	$ 750	$ 92,695
Accumulated depreciation					
Balance at January 1, 2023	$ 401	$ 16,482	$ 3,395	$ –	$ 20,278
Depreciation	68	2,538	624	–	3,230
Disposals/retirements	(1)	(37)	(77)	–	(115)
Balance at December 31, 2023	$ 468	$ 18,983	$ 3,942	$ –	$ 23,393
Balance at January 1, 2022	$ 342	$ 14,140	$ 2,874	$ –	$ 17,356
Depreciation	59	2,376	586	–	3,021
Disposals/retirements	–	(34)	(65)	–	(99)
Balance at December 31, 2022	$ 401	$ 16,482	$ 3,395	$ –	$ 20,278
Carrying amounts					
At December 31, 2023	$ 3,465	$ 71,265	$ 3,452	$ 626	$ 78,808
At December 31, 2022	$ 2,822	$ 65,860	$ 2,985	$ 750	$ 72,417

At December 31, 2023 property plant and equipment with a carrying amount of $78,808 (2022 - $72,417) are subject to a general security agreement.

There were no borrowing costs capitalized as part of the cost of property, plant and equipment in 2023 or 2022.

7. Intangible assets:

	Computer software	Land rights	Total
Cost			
Balance at January 1, 2023	$ 2,072	$ 238	$ 2,310
Additions	1,196	–	1,196
Balance at December 31, 2023	$ 3,268	$ 238	$ 3,506
Balance at January 1, 2022	$ 1,657	$ 238	$ 1,895
Additions	415	–	415
Balance at December 31, 2022	$ 2,072	$ 238	$ 2,310
Accumulated amortization			
Balance at January 1, 2023	$ 1,158	$ 41	$ 1,199
Amortization	380	5	385
Balance at December 31, 2023	$ 1,538	$ 46	$ 1,584
Balance at January 1, 2022	$ 899	$ 36	$ 935
Amortization	259	5	264
Balance at December 31, 2022	$ 1,158	$ 41	$ 1,199
Carrying amounts			
At December 31, 2023	$ 1,730	$ 192	$ 1,922
At December 31, 2022	$ 914	$ 197	$ 1,111

8. Income tax expense:

Income tax expense is comprised of:

	2023	2022
Current tax expense	$ (23)	$ 3
Deferred tax expense	512	591
	$ 489	$ 594

Reconciliation of effective tax rate:

	2023	2022
Income before taxes	$ 5,961	$ 4,338
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected tax expense on income at statutory rates	1,579	1,149
Increase in income taxes resulting from:		
Non-taxable amounts	92	103
Net movement in regulatory balances	(514)	(656)
Other items	(668)	(2)
Income tax expense	$ 489	$ 594
Effective income tax rate	8.2%	13.7%

Significant components of the Corporation’s deferred tax balances:

	2023	2022
Deferred tax assets (liabilities) consist of the following:		
Property, plant, equipment (regulated)	$ (4,704)	$ (3,812)
Post-employment benefits	560	579
Total deferred tax liabilities to be realized by customers	(4,144)	(3,233)
Deferred tax liabilities from non-regulated solar assets	(18)	(20)
Other deferred tax assets	481	97
	$ (3,681)	$ (3,156)

9. Regulatory balances:

The Corporation has determined that certain debit and credit balances arising from rate-regulated activities qualify for regulatory accounting treatment in accordance with IFRS 14 and the OEB's prescribed accounting procedures for electricity distributors. The regulatory balances are comprised of regulatory debit balances of $8,814 (2022 - $11,605) and regulatory credit balances of $3,522 (2022 - $2,439) for a net regulatory asset of $5,292 (2022 - $9,166).

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points, with the exception of the tax balances. In 2023, the rate was 4.73% for the period January to March, 4.98% for the period April to September and 5.49% for the period for the period October to December.

The regulatory balances for the Corporation consist of the following:

(a) Settlement Variance:

This account includes the variances between amounts charged by the Corporation, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by the Corporation such as commodity charges, retail transmission rates and wholesale market services charges. The Corporation has deferred the variances and related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. This account also includes variances between the amounts approved for disposition by the OEB and the amounts collected or paid through OEB approved rate riders.

Settlement variances are reviewed annually as part of a COS or IRM application submitted to the OEB and a request for disposition is made if the aggregate of the settlement accounts exceeds the OEB's prescribed materiality level.

(b) Regulatory settlement accounts:

Regulatory settlement accounts include those settlement variances for which the OEB has approved for disposition. On March 23, 2023, the OEB issued a final rate order approving 2023 rates effective May 1, 2023.

(c) Customer Liability for Deferred Taxes:

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from or paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

9. Regulatory balances (continued):

(d) Other:

This deferral account includes the allowable costs associated with the transition to IFRS and other miscellaneous regulatory accounts.

Reconciliation of the carrying amount for each class of regulatory balances:

Regulatory deferral account debit balances	January 1, 2023	Additions/ transfers	Recovery/ reversal	December 31, 2023	Remaining years
Group 1 deferred accounts	$ 5,875	$ (1,944)	$ (257)	$ 3,674	1
Regulatory transition to IFRS	148	–	–	148	1-2
Regulatory settlement account	2,879	25	(1,423)	1,481	1
Other regulatory accounts	163	294	–	457	1-2
Income tax	2,540	514	–	3,054	1-2
	$ 11,605	$ (1,111)	$ (1,680)	$ 8,814	

Regulatory deferral account debit balances	January 1, 2022	Additions/ transfers	Recovery/ reversal	December 31, 2022	Remaining years
Group 1 deferred accounts	$ 6,220	$ 1,524	$ (1,869)	$ 5,875	1-2
Regulatory transition to IFRS	148	–	–	148	3
Regulatory settlement account	5,738	34	(2,893)	2,879	1-2
Other regulatory accounts	129	34	–	163	3
Income tax	1,884	656	–	2,540	3
	$ 14,119	$ 2,248	$ (4,762)	$ 11,605	

Regulatory deferral account credit balances	January 1, 2023	Additions/ transfers	Recovery/ reversal	December 31, 2023	Remaining years
Group 1 deferred accounts	$ (244)	$ 797	$ (808)	$ (255)	1
Regulatory settlement account	(1,670)	1,736	(2,681)	(2,615)	1
Other regulatory accounts	(525)	(127)	–	(652)	1-2
	$ (2,439)	$ 2,406	$ (3,489)	$ (3,522)	

Regulatory deferral account credit balances	January 1, 2022	Additions/ transfers	Recovery/ reversal	December 31, 2022	Remaining years
Group 1 deferred accounts	$ (234)	$ (104)	$ 94	$ (244)	1-2
Regulatory settlement account	(2,506)	(273)	1,109	(1,670)	1-2
Other regulatory accounts	(428)	(97)	–	(525)	3
	$ (3,168)	$ (474)	$ 1,203	$ (2,439)	

The “Additions/Transfers” column consists of new additions to regulatory balances (for both debits and credits). The “Recovery/Reversal” column consists of amounts collected or paid through rate riders or transactions reversing an existing regulatory balance to recover. Recoveries and reversals occur as a result of the approval of an application. There were no reversals of regulatory balances for the year ended December 31, 2023.

10. Accounts payable and accrued liabilities:

	2023	2022
Accounts payable – energy purchases	$ 6,048	$ 5,488
Payroll payable	258	301
Due to related parties	868	453
Water and waste water billings due to Ultimate Shareholders	2,730	2,774
Other accounts payable and accrued liabilities	1,697	1,116
	$ 11,601	$ 10,132

11. Long-term debt:

	2023	2022
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each March. Interest is payable at a stated interest rate of 4.0% (2022 - 3.8%). The agreement expires December 31, 2027. The debt is owing to two of the four shareholders of the parent company as follows:		
Municipality of Leamington	$ 2,150	$ 2,150
Town of Tecumseh	1,545	1,545
	3,695	3,695
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $36, bearing an interest rate of 3.25% due November, 2029	2,354	2,710
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $17, bearing an interest rate of 3.18% due August, 2027	2,247	2,376
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.73% due July, 2028	2,393	2,514

11. Long-term debt (continued):

		2023		2022
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.73% due July, 2028		2,393		2,514
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.90% due November, 2028		2,443		2,561
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $39, bearing an interest rate of 2.95% due September, 2029		5,837		6,124
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $26, bearing an interest rate of 2.00% due November, 2030		4,490		4,711
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $31, bearing an interest rate of 2.079% due December, 2030.		5,251		5,505
Fixed rate loan – TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $21, bearing an interest rate of 2.19% due October, 2026.		3,646		3,812
Fixed rate loan – TD Canada Trust is a 2 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $26, bearing an interest rate of 4.94% due December, 2025.		4,000		–
		38,749		36,522
Less: Current portion of long-term debt		3,420		2,512
	$	35,329	$	34,010

11. Long-term debt (continued):

Approximate long-term principal repayments over the next five years and thereafter are as follows:

2024	$ 3,420
2025	6,498
2026	5,801
2027	4,236
2028	6,918
Thereafter	11,876
	$ 38,749

The loans are secured by a General Security Agreement over the assets of the Corporation.

12. Post-employment benefits:

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2023, the Corporation made employer contributions of $417 to OMERS (2022 - $389) of which $125 (2022 - $117) has been capitalized as part of property, plant and equipment. The Corporation estimates that a contribution of $405 to OMERS will be made during the next fiscal year.

(b) Post-employment benefits other than pension:

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans. The most recent valuation was completed December 31, 2023.

Reconciliation of the obligation	2023	2022
Defined benefit obligation, beginning of year	$ 2,185	$ 2,674
Included in profit or loss		
Current service cost	52	67
Interest cost	107	72
	2,344	2,813
Benefits paid	(180)	(194)
	2,164	2,619
Actuarial gains included in OCI:		
Changes in discount rate	68	(434)
Changes in demographic assumptions	(117)	–
	(49)	(434)
Defined benefit obligation, end of year	$ 2,115	$ 2,185

12. Post-employment benefits (continued):

(b) Post-employment benefits other than pension (continued):

Actuarial assumptions	2023	2022
Discount (interest) rate	4.60%	5.00%
General inflation	2.00%	2.00%
Medical Costs	5.50%	6.25%
Dental Costs	4.00%	4.50%

Medical costs are estimated to increase at a rate which declines over time from 5.50% per annum in 2023 to 4.0% by 2037.

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $164. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $189.

A 1% increase in the assumed trend rate would result in the defined benefit obligation increasing by $168. A 1% decrease in the assumed trend rate would result in the defined benefit obligation decreasing by $149.

13. Share capital:

	2023	2022
Authorized:		
Unlimited number of common shares, Class A, voting		
Unlimited number of common shares, Class B, non-voting		
Issued:		
50 common shares, Class A voting, and 15,772,796 common shares, Class B non-voting	$ 15,773	$ 15,773

Dividends

The holders of the common shares are entitled to receive dividends from time to time.

The Corporation paid aggregate dividends in the year on the issued common shares of $0.06873 (2022 - $0.06771) per share. The corporation declared dividends on the issued common shares amounting to $1,100 (2022 - $1,084).

14. Revenue:

Revenue consists of the following:

		2023		2022
Revenue from contracts with customers				
Sale of energy	$	67,435	$	69,709
Distribution revenue		17,589		17,616
Solar Generation		24		25
Ancillary services revenue		(105)		(12)
Billing services to Municipal shareholders		330		320
Joint use pole rentals		265		249
Other regulatory service charges		354		364
Miscellaneous		143		51
Revenue from other sources				
Deferred revenue recognized from capital contributions		273		221
	$	86,308	$	88,543

Sale of energy and distribution revenue consist of the following:

		2023		2022
Residential service	$	54,478	$	55,903
General service less than 50KW		7,910		8,957
General service 50 to 4,999KW		22,114		21,732
Intermediate and Embedded distributor		374		357
Unmetered and other		148		376
	$	85,024	$	87,325

15. Operating expenses:

		2023		2022
Contract/consulting	$	1,139	$	1,174
Materials and supplies		1,356		1,201
Salaries, wages and benefits		3,245		3,218
Cost of billing services for ultimate shareholders		300		291
Post-employment benefit plans		154		140
Vehicles		170		193
Management charges from Parent		1,366		1,144
Bad debts		205		71
Other		1,237		1,265
	$	9,172	$	8,697

16. Net finance costs:

		2023		2022
Finance income				
Interest income on bank deposits	$	31	$	17
Finance costs				
Interest expense on long-term debt		1,048		1,091
Interest expense on customer deposits		36		6
Other		175		88
		1,259		1,185
Net finance costs recognized in profit or loss	$	(1,228)	$	(1,168)

17. Commitments and contingencies:

Contractual Obligations:

General:

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2023, no assessments have been made.

Letter of Credit:

A letter of credit in the amount of $2,900 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator for the commodity purchases and market services provided. This letter of credit has no term of expiry and is normally renewed annually.

Construction Bonding Agreement:

Essex Energy Corporation, an affiliate, has entered into a construction bonding agreement which has an indemnity requirement that extends to this Corporation for any and all indemnity losses to a maximum limit of $3 million.

18. Related party transactions:

(a) Parent and ultimate controlling party:

The sole shareholder of the Corporation is Essex Power Corporation ("EPC") which is wholly owned by Towns of Amherstburg, LaSalle and Tecumseh, and the Municipality of Leamington ("ultimate parents"). The ultimate parents produce financial statements that are available for public use.

(b) Companies under common control:

Essex Power Corporation owns 100% of Essex Energy Corporation

Essex Energy Corporation owns 100% of Utilismart Corporation

Essex Energy Corporation owns 100% of EE Solar Partners Inc.

Essex Energy Corporation owns 100% of ASI SPE 106 Ltd

Essex Energy Corporation owns 50% of Enertrace Services Ltd.

EE Solar Partners Inc. owns 49% of Muskoka Solar LP

EE Solar Partners Inc. owns 49% of Rosseau Solar LP

Utilismart Corporation owns 100% of Wattsworth Analysis Inc.

(c) Outstanding balances with related parties:

	2023	2022
Balances due to:		
Essex Power Corporation	$ 526	$ 115
Essex Energy Corporation	195	163
Utilismart Corporation	76	32
Wattsworth Analysis Inc.	–	3
Municipality of Leamington	–	81
Town of Tecumseh	1,215	1,167
Town of Amherstburg	1,577	1,666
	$ 3,589	$ 3,227

	2023	2022
Balances due from:		
Essex Energy Corporation	22	27
Town of LaSalle	1	1
Town of Tecumseh	30	18
Town of Amherstburg	32	15
Municipality of Leamington	20	20
	$ 105	$ 81

All balances due from and due to related parties listed above are included within accounts receivable and accounts payable respectively. Amounts are non-interest bearing with repayment terms similar to other trade accounts receivable and accounts payable.

18. Related party transactions:

(d) Transactions with parent:

During the year, the corporation paid management fees of $1,366 (2022- $1,144) to its parent.

(e) Transactions with companies under common control:

In the ordinary course of business, the corporation incurred the following transactions with other related parties under common control:

		2023		2022
Sold operating expense services to:				
Essex Energy Corporation	$	170	$	128
Purchased operating expense and solar services from:				
Essex Energy Corporation		885		685
Utilismart Corporation		546		372
Wattsworth Analysis Inc.		–		36

(f) Transactions with ultimate parent:

The Corporation delivers electricity to these entities throughout the year for the electricity needs of the Towns and Municipality. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides additional services to the Towns and Municipality, including billing and customer care services. The total revenues related to these services for 2023 were $330 (2022 - $320).

(g) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members. The compensation paid or payable is as follows:

		2023		2022
Directors' fees	$	22	$	22
Salaries, bonuses and other short-term benefits		484		452
	$	506	$	474

19. Financial instruments and risk management:

Fair value disclosure:

The carrying values of accounts receivable, unbilled revenue, accounts payable and accrued liabilities and bank indebtedness approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt at December 31, 2023 is $26,326 (2022 - $26,286). The fair value is calculated based on the present value of the future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rate used to calculate fair value at December 31, 2023 was 4.5% (2022 - 4.5%). All financial instruments are considered level 1 on the fair value hierarchy.

Financial risks:

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Towns of Amherstburg, LaSalle, Tecumseh and the Municipality of Leamington. No single customer accounts for a balance in excess of 7% of total electricity accounts receivable.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the loss allowance at December 31, 2023 is $231 (2022 - $125). An impairment loss of $205 (2022 - $71) was recognized during the year.

19. Financial instruments and risk management (continued):

Financial risks (continued):

(a) Credit risk (continued):

The Corporation's credit risk associated with accounts receivable is primarily related to payments from its electricity distribution customers. At December 31, 2023, approximately $236 (2022 - $251) is considered 60 or more days past due. The Corporation has over 33,000 customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2023, the Corporation holds security deposits in the amount of $396 (2022 - $404).

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $9,000 credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2023, $nil had been drawn under the Corporation's credit facility (2022-$3,173) and is presented in bank indebtedness on the statement of financial position.

The Corporation also has a bilateral facility for $2,900 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which none has been drawn and posted with the IESO during 2023 or 2022.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days. Customer deposits are due on demand. The scheduled repayments associated with long-term debt are described within note 11.

19. Financial instruments and risk management (continued):

(d) Capital disclosures:

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation’s definition of capital includes shareholder’s equity and long-term debt. As at December 31, 2023, shareholder’s equity amounts to $31,904 (2022 - $31,370) and long-term debt amounts to $38,749 (2022 - $36,522).

Schedule of Instalment Remittances

Name of corporation contact

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Payments made in F22	78,576
	Final payment	

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 78,576 **A**

Total instalments credited to the taxation year per T9 78,576 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Corporation's name	Business number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

General Index of Financial Information

Notes to the financial statements

Notes to the Finacial Statements will be forwarded separately.

REGULATION 1101 (5b.1) ELECTION

Attachment to Schedule 8

Essex Powerlines Corporation hereby elects, pursuant to the provisions of Regulation 1101(5b.1) of the Income Tax Regulations, to include the current year eligible non-residential building addition {as defined in Regulation 1104(2)}, with a cost of $225,539 in a separate Class 1 for capital cost allowance purposes as permitted by Regulation 1100(1)(a.2).

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			1,633,738	A

Add:

Provision for income taxes – current	101	-23,357		
Provision for income taxes – deferred	102	527,305		
Interest and penalties on taxes	103	5,071		
Amortization of tangible assets	104	3,615,395		
Loss on disposal of assets	111	352		
Non-deductible meals and entertainment expenses	121	8,998		
Reserves from financial statements – balance at the end of the year	126	231,459		
Subtotal of additions		4,365,223 ▶	4,365,223	

Add:

Other additions:

	1 Description 605	2 Amount 295
1	Inducement under 12(1)(x) ITA	4,066
2	Post-employment benefits - expenses	153,990
	Total of column 2	158,056 ▶

	296	158,056		
Subtotal of other additions	199	158,056 ▶	158,056	D
Total additions	500	4,523,279 ▶	4,523,279	
Amount A **plus** line 500			6,157,017	B

Deduct:

Capital cost allowance from Schedule 8	403	7,025,440		
Reserves from financial statements – balance at the beginning of the year	414	124,857		
Subtotal of deductions		7,150,297 ▶	7,150,297	

Deduct:

Non-taxable/deductible other comprehensive income items	347	49,479		

Other deductions:

	1 Description 705	2 Amount 395
1	See attachment	514,000
2	Post-employment benefits payments	175,090
	Total of column 2	689,090 ▶

	396	689,090		
Subtotal of other deductions	499	738,569 ▶	738,569	E
Total deductions	510	7,888,866 ▶	7,888,866	
Net income (loss) for income tax purposes (amount B **minus** line 510)			-1,731,849	C

Enter amount C on line 300 of the T2 return.

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Description	Operator (Note)	Amount	
Decrease of deferred tax liability booked to regulatory movement acct	+	514,000	00
	+		
	Total	514,000	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 295 – Amount

Title Line 295 – Amount

Description	Operator (Note)	Amount
20-5645-0000-000-00 EMPL FUTURE BENEFIT EXP (accrued)		153,990 00
	+	
	+	
	+	
	Total	153,990 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 102 – Provision for income taxes – deferred

Title Line 102 – Provision for income taxes – deferred

Description	Operator (Note)	Amount	
20-7025-0000-000-00 Future Taxes on Other Comprehensive Income		13,100	00
80300 Future tax expense	+	514,205	00
	+		
	Total	527,305	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Federal

A		
☒	Investment tax credit from apprenticeship job creation expenditures	2,000
☒	Investment tax credit from child care spaces expenditures	
☐	Canadian film or video production tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
☐	Film or video production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
☒	Investment tax credit claimed on contributions made to SR&ED farming organizations	
☐	Canadian journalism labour tax credit	
☐	Return of fuel charge proceeds to farmers tax credit	
☐	Air quality improvement tax credit* * Please verify if the credit amount relates to depreciable property For more information, consult the Help (F1).	

Ontario

A		
☐	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☒	Ontario co-operative education tax credit	2,066
☐	Ontario computer animation and special effects tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
☐	Ontario film and television tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
☐	Ontario production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
☐	Ontario interactive digital media tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
☐	Ontario book publishing tax credit	
☐	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☐	Ontario business-research institute tax credit	
☐	Ontario community food program donation tax credit for farmers	

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Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83
  - deductible dividends under subsection 138(6)
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (a.1), (b) or (d)
  - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3)
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations (as defined in subsection 186(3)).
- A payer corporation is **connected** with a recipient corporation at any time in a tax year, if at that time the recipient corporation meets either of the following conditions:
  - it controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b)
  - it owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A1 – Enter "X" if dividends were received from a foreign source.
  Column F1 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H, H.1, I, I.1, I.2 and L **only if** the payer corporation is **connected**.

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing columns J, K and L use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYYMMDD 220	E Non-taxable dividends under section 83 230
1			2			
					Total of column E (enter amount on line 402 of Schedule 1)	

Part 1 – Dividends received in the tax year (continued)

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1), (b), or (d) [1] **240**	F1	G Eligible dividends included in column F **242**	H Total taxable dividends paid by the **connected** payer corporation (line 460 in Schedule 3 for the tax year in column D) **250**	H.1 Total eligible dividends paid by the **connected** payer corporation (line 465 in Schedule 3 for the tax year in column D)	I Dividend refund of the **connected** payer corporation (for tax year in column D) [2] **260**
1						

	I.1 Eligible dividend refund of the **connected** payer corporation from its eligible refundable dividend tax on hand (ERDTOH) (amount CC from T2 return for the tax year in column D)	I.2 Additional non-eligible dividend refund of the **connected** payer corporation from its ERDTOH (amount II from T2 return for the tax year in column D)	J Part IV tax for eligible dividends. Dividends (from column G) **multiplied** by 38 1/3% [3] **265**	K Part IV tax before deductions. Dividends (from column F) **multiplied** by 38 1/3% [4] **275**	L Part IV tax before deductions on taxable dividends received from **connected** corporations [5] **280**
1					

Total of column L (enter amount on line 2E in Part 2) ____________

Taxable dividends received from connected corporations (total amounts from column F with code 1 in column B) . . . . ____________ 1A

Taxable dividends received from non-connected corporations (total amounts from column F with code 2 in column B) . . . . ____________ 1B

Subtotal (amount 1A **plus** amount 1B, include this amount on line 320 of the T2 return) ____________ 1C

Eligible dividends received from connected corporations (total amounts from column G with code 1 in column B) . . . . ____________ 1D

Eligible dividends received from non-connected corporations (total amounts from column G with code 2 in column B) . . . . ____________ 1E

Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column K with code 1 in column B) . . . . ____________ 1F

Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column K with code 2 in column B) . . . . ____________ 1G

Subtotal (amount 1F **plus** amount 1G) ____________ ▶ ____________ 1H

Part IV tax on eligible dividends received from connected corporations (total amounts from column J with code 1 in column B) . . . . ____________ 1I

Part IV tax on eligible dividends received from non-connected corporations (total amounts from column J with code 2 in column B) . . . . ____________ 1J

Subtotal (amount 1I **plus** amount 1J) ____________ ▶ ____________ 1K

Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H **minus** amount 1K) . . . . ____________ 1L

1 If taxable dividends are received, enter the amount in column F, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column K (and column J, if applicable). Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the **connected** payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to column I **divided** by column H **multiplied** by column G.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to column I **divided** by column H **multiplied** by column F.

5 For the purpose of calculating your eligible refundable dividend tax on hand (ERDTOH), Part IV tax on taxable dividends received from **connected** corporations (with a tax year starting after 2018) is equal to the sum of Part IV tax on eligible dividends and non-eligible dividends received from **connected** corporations to the extent that such dividends caused a dividend refund to those corporations from their ERDTOH.

Part IV tax before deductions on taxable dividends received from **connected** corporations for purposes of column L is the sum of (i) and (ii), where

(i) Part IV tax on eligible dividends received from **connected** corporations is equal to amount CC of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 465 of the **connected** payer corporation, **multiplied** by column G; and

(ii) Part IV tax on non-eligible dividends received from **connected** corporations is equal to amount II of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 470 of the **connected** payer corporation, **multiplied** by the difference between columns F and G.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received before deductions (amount 1H in part 1) . . . . ______ 2A

Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) . . . . . **320** ______

Subtotal (amount 2A **minus** line 320) ______ ▶ ______ 2B

Current-year non-capital loss claimed to reduce Part IV tax . . . . **330** ______

Non-capital losses from previous years claimed to reduce Part IV tax . . . . **335** ______

Current-year farm loss claimed to reduce Part IV tax . . . . **340** ______

Farm losses from previous years claimed to reduce Part IV tax . . . . **345** ______

Total losses applied against Part IV tax (total of lines 330 to 345) ______ 2C

Amount 2C **multiplied** by 38 1 / 3 % . . . . ______ 2D

Part IV tax payable (amount 2B **minus** amount 2D, if negative enter "0") . . . . **360** ______

(enter amount on line 712 of the T2 return)

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax before deductions on taxable dividends received from connected corporations (total of column L in part 1) . . . . ______ 2E

Amount 4A from Schedule 43 . . . . ______ 2F

Part IV tax payable on taxable dividends received from connected corporations
(amount 2E **minus** amount 2F, if negative enter "0") . . . . ______ 2G

(enter at amount C on page 7 of the T2 return)

Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1) . . . . ______ 2H

Amount 4C from Schedule 43 . . . . ______ 2I

Part IV tax payable on taxable dividends received from non-connected corporations
(amount 2H **minus** amount 2I, if negative enter "0") . . . . ______ 2J

(enter at amount D on page 7 of the T2 return)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the recipient corporation with which you are connected, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	M Name of recipient corporation with which you are connected **400**	N Business number **410**	O Tax year-end of recipient corporation in which the dividends in column P were received YYYYMMDD **420**	P Taxable dividends paid to recipient corporations with which you are connected **430**	Q Eligible dividends included in column P **440**
1	Essex Power Corporation	86953 5435 RC0001	2023-12-31	1,100,000	
				1,100,000 (Total of column P)	(Total of column Q)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

Total taxable dividends paid in the tax year to other than connected corporations	**450**	
Eligible dividends included in line 450	**455**	
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column P **plus** line 450)	**460**	1,100,000
Total eligible dividends paid in the tax year (total of column Q **plus** line 455)	**465**	
Total non-eligible taxable dividends paid in the tax year (line 460 **minus** line 465)	**470**	1,100,000

Complete this part to determine the following amounts in order to calculate the dividend refund.

Line 465 **multiplied** by 38 1 / 3 % (enter at amount AA on page 7 of the T2 return)		3A
Line 470 **multiplied** by 38 1 / 3 % (enter at amount DD on page 7 of the T2 return)	421,667	3B

Part 4 – Total dividends paid in the tax year

Complete this part **if** the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)		1,100,000
Other dividends paid in the tax year (total of 510 to 540)		
Total dividends paid in the tax year	**500**	1,100,000

Dividends paid out of capital dividend account	**510**	
Capital gains dividends	**520**	
Dividends paid on shares described in subsection 129(1.2)	**530**	
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	**540**	
Subtotal (total of lines 510 to 540)		► 4A

Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount 4A) 1,100,000 4B

Attached Schedule with Total

Taxable dividends paid to recipient corporations with which you are connected

Title Taxable dividends paid to connected corporations

Description	Operator (Note)	Amount	
Dividends declared on Common Shares		1,100,000	00
	+		
	Total	1,100,000	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the federal Income Tax Act, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the T2 Corporation – Income Tax Guide.
- File this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the federal Income Tax Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes . . . . -1,731,849 1A

Net capital losses deducted in the year (enter as a positive amount) 1B
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6) 1C
Amount of Part VI.1 tax deductible under paragraph 110(1)(k) 1D
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2) 1E
Employer deduction for non-qualified securities – Paragraph 110(1)(e) 1F
Subtotal (total of amounts 1B to 1F) ▶ 1G
Subtotal (amount 1A **minus** amount 1G; if positive, enter "0" -1,731,849 1H

Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions 1I
Subtotal (amount 1H **minus** amount 1I) -1,731,849 1J

Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss) 1K

Current-year non-capital loss (amount 1J **plus** amount 1K; if positive, enter "0") . . . . . . -1,731,849 1L
If amount 1L is negative, enter it on line 110 as a positive.

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year 1M
Non-capital loss expired **(note 1)** **100**
Non-capital losses at the beginning of the tax year (amount 1M **minus** line 100) . . . . . . **102** ▶

Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary **(note 2)** corporation **105**
Current-year non-capital loss (from amount 1L) **110** 1,731,849
Subtotal (line 105 **plus** line 110) 1,731,849 ▶ 1,731,849 1N

Subtotal (line 102 **plus** amount 1N) 1,731,849 1O

Note 1: A non-capital loss expires after **20 tax years** and an allowable business investment loss becomes a net capital loss after **10 tax years**.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Other adjustments (includes adjustments for an acquisition of control)	**150**			
Section 80 – Adjustments for forgiven amounts	**140**			
Subsection 111(10) – Adjustments for fuel tax rebate				
Non-capital losses of previous tax years applied in the current tax year Enter line 130 on line 331 of the T2 return.	**130**			
Current and previous years non-capital losses applied against current-year taxable dividends subject to Part IV tax **(note 3)**	**135**			
Subtotal (total of lines 150, 140, 130 and 135)			▶	1P
Non-capital losses before any request for a carryback (amount 1O **minus** amount 1P)			1,731,849	1Q

Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	**901**			
Second previous tax year to reduce taxable income	**902**	407,892		
Third previous tax year to reduce taxable income	**903**			
First previous tax year to reduce taxable dividends subject to Part IV tax	**911**			
Second previous tax year to reduce taxable dividends subject to Part IV tax	**912**			
Third previous tax year to reduce taxable dividends subject to Part IV tax	**913**			
Total of requests to carry back non-capital losses to previous tax years (total of lines 901 to 913)		407,892 ▶	407,892	1R
Closing balance of non-capital losses to be carried forward to future tax years (amount 1Q **minus** amount 1R)	**180**		1,323,957	

Note 3: Line 135 is the total of lines 330 and 335 from Schedule 3, Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	**200**			
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	**205**			
Subtotal (line 200 **plus** line 205)		▶		2A
Other adjustments (includes adjustments for an acquisition of control)	**250**			
Section 80 – Adjustments for forgiven amounts	**240**			
Subtotal (line 250 **plus** line 240)		▶		2B
Subtotal (amount 2A **minus** amount 2B)				2C
Current-year capital loss (from the calculation on Schedule 6, Summary of Dispositions of Capital Property)	**210**			
Unused non-capital losses from the 11th previous tax year **(note 4)**			2D	
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year **(note 5)**			2E	
Enter amount 2D or 2E, whichever is less	**215**			
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	**220**			
Subtotal (amount 2C **plus** line 210 **plus** line 220)				2F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220.

Note 4: Determine the amount of the non-capital loss from the **11th previous tax year**, and enter the part of the non-capital loss that was not deducted in the **previous 11 years**.

Note 5: Enter the amount of the ABILs from the **11th previous tax year**. Enter the full amount on amount 2E.

Part 2 – Capital losses (continued)

Capital losses from previous tax years applied against the current-year net capital gain **(note 6)** **225**

Capital losses before any request for a carryback (amount 2F **minus** line 225) 2G

Request to carry back capital loss to (note 7):

	Capital gain (100%)		Amount carried back (100%)
First previous tax year		**951**	
Second previous tax year		**952**	
Third previous tax year		**953**	

Subtotal (total of lines 951 to 953) ▶ 2H

Closing balance of capital losses to be carried forward to future tax years (amount 2G **minus** amount 2H) **(note 8)** **280**

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current tax year, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **divide** this amount by 2. The result represents the 50% inclusion rate.

Note 8: Capital losses can be carried forward indefinitely.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year 3A

Farm loss expired **(note 9)** **300**

Farm losses at the beginning of the tax year (amount 3A **minus** line 300) . . . . **302** ▶

Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation . **305**

Current-year farm loss (amount 1K in Part 1) **310**

Subtotal (line 305 **plus** line 310) ▶ 3B

Subtotal (line 302 **plus** amount 3B) 3C

Other adjustments (includes adjustments for an acquisition of control) **350**

Section 80 – Adjustments for forgiven amounts **340**

Farm losses of previous tax years applied in the current tax year **330**

Enter line 330 on line 334 of the T2 Return.

Current and previous years farm losses applied against current-year taxable dividends subject to Part IV tax **(note 10)** **335**

Subtotal (total of lines 350, 340, 330 and 335) ▶ 3D

Farm losses before any request for a carryback (amount 3C **minus** amount 3D) 3E

Request to carry back farm loss to:

First previous tax year to reduce taxable income **921**

Second previous tax year to reduce taxable income **922**

Third previous tax year to reduce taxable income **923**

First previous tax year to reduce taxable dividends subject to Part IV tax **931**

Second previous tax year to reduce taxable dividends subject to Part IV tax **932**

Third previous tax year to reduce taxable dividends subject to Part IV tax **933**

Subtotal (total of lines 921 to 933) ▶ 3F

Closing balance of farm losses to be carried forward to future tax years (amount 3E **minus** amount 3F) **380**

Note 9: A farm loss expires after **20 tax years**.

Note 10: Line 335 is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business **485**

(line 485 – $2,500) **divided** by 2 . . . . 4A

Amount 4A or $ 15,000 , whichever is less . . . . ▶ 4B

2,500 4C

Subtotal (amount 4B **plus** amount 4C) 2,500 ▶ 2,500 4D

Current-year restricted farm loss (line 485 **minus** amount 4D) 4E

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year 4F

Restricted farm loss expired **(note 11)** **400**

Restricted farm losses at the beginning of the tax year (amount 4F **minus** line 400) . . . . **402** ▶

Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation **405**

Current-year restricted farm loss (from amount 4E) **410**

Enter line 410 on line 233 of Schedule 1, Net Income (Loss) for Income Tax Purposes.

Subtotal (line 405 **plus** line 410) ▶ 4G

Subtotal (line 402 **plus** amount 4G) 4H

Restricted farm losses from previous tax years applied against current farming income **430**

Enter line 430 on line 333 of the T2 return.

Section 80 – Adjustments for forgiven amounts **440**

Other adjustments **450**

Subtotal (total of lines 430 to 450) ▶ 4I

Restricted farm losses before any request for a carryback (amount 4H **minus** amount 4I) 4J

Request to carry back restricted farm loss to:

First previous tax year to reduce farming income **941**

Second previous tax year to reduce farming income **942**

Third previous tax year to reduce farming income **943**

Subtotal (total of lines 941 to 943) ▶ 4K

Closing balance of restricted farm losses to be carried forward to future tax years (amount 4J **minus** amount 4K) **480**

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 11: A restricted farm loss expires after **20 tax years**.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			5A
Listed personal property loss expired **(note 12)**	500		
Listed personal property losses at the beginning of the tax year (amount 5A **minus** line 500)	502	▶	
Current-year listed personal property loss (from Schedule 6)	510		
Subtotal (line 502 **plus** line 510)			5B
Listed personal property losses from previous tax years applied against listed personal property gains	530		
Enter line 530 on line 655 of Schedule 6.			
Other adjustments	550		
Subtotal (line 530 **plus** line 550)		▶	5C
Listed personal property losses remaining before any request for a carryback (amount 5B **minus** amount 5C)			5D

Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961		
Second previous tax year to reduce listed personal property gains	962		
Third previous tax year to reduce listed personal property gains	963		
Subtotal (total of lines 961 to 963)		▶	5E
Closing balance of listed personal property losses to be carried forward to future tax years (amount 5D **minus** amount 5E)	580		

Note 12: A listed personal property loss expires after **7 tax years**.

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number **600**	Tax year ending YYYY/MM/DD **602**	Corporation's share of limited partnership loss **604**	Corporation's at-risk amount **606**	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses **608**	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6) **620**
1.							
						Total (enter this amount on line 222 of Schedule 1)	

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number **630**	Tax year ending YYYY/MM/DD **632**	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary **634**	Corporation's at-risk amount **636**	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses **638**	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) **650**
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number **660**	Limited partnership losses at the end of the previous tax year **662**	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary **664**	Current-year limited partnership losses (from line 620) **670**	Limited partnership losses applied in the current year (must be equal to or less than line 650) **675**	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) **680**
1.						
				Total (enter this amount on line 335 of the T2 return)		

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), tick the box . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A	1,731,849		407,892	N/A		1,323,957
1st preceding taxation year 2022-12-31		N/A		N/A			
2nd preceding taxation year 2021-12-31		N/A		N/A			
3rd preceding taxation year 2020-12-31		N/A		N/A			
4th preceding taxation year 2019-12-31		N/A		N/A			
5th preceding taxation year 2018-12-31		N/A		N/A			
6th preceding taxation year 2017-12-31		N/A		N/A			
7th preceding taxation year 2016-12-31		N/A		N/A			
8th preceding taxation year 2015-12-31		N/A		N/A			
9th preceding taxation year 2014-12-31		N/A		N/A			
10th preceding taxation year 2013-12-31		N/A		N/A			
11th preceding taxation year 2012-12-31		N/A		N/A			
12th preceding taxation year 2011-12-31		N/A		N/A			
13th preceding taxation year 2010-12-31		N/A		N/A			
14th preceding taxation year 2009-12-31		N/A		N/A			
15th preceding taxation year 2008-12-31		N/A		N/A			
16th preceding taxation year 2007-12-31		N/A		N/A			
17th preceding taxation year 2006-12-31		N/A		N/A			
18th preceding taxation year 2005-12-31		N/A		N/A			
19th preceding taxation year 2004-12-31		N/A		N/A			
20th preceding taxation year 2003-12-31		N/A		N/A			*
Total		1,731,849		407,892			1,323,957

*** This balance expires this year and will not be available next year.**

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- Use this schedule if any of the following apply to your corporation during the tax year:
  - it had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B, and D in Part 1)
  - it is claiming provincial or territorial tax credits or rebates (see Part 2)
  - it has to pay taxes, other than income tax, for Newfoundland and Labrador or Ontario (see Part 2)
- All legislative references are to the federal Income Tax Regulations (the Regulations).
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Allocation of taxable income

100 ______________ Enter the regulation that applies (402 to 413).

A Jurisdiction. (tick **yes** if your corporation had a permanent establishment in the jurisdiction during the tax year) **Note 1**		B Total salaries and wages paid in jurisdiction	C B **multiplied** by taxable income, **divided** by G	D Gross revenue attributable to jurisdiction	E D **multiplied** by taxable income, **divided** by H	F Allocation of taxable income (C + E x 1/2) **Note 2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	**003** Yes ☐	**103**		**143**		
Newfoundland and Labrador Offshore	**004** Yes ☐	**104**		**144**		
Prince Edward Island	**005** Yes ☐	**105**		**145**		
Nova Scotia	**007** Yes ☐	**107**		**147**		
Nova Scotia Offshore	**008** Yes ☐	**108**		**148**		
New Brunswick	**009** Yes ☐	**109**		**149**		
Quebec	**011** Yes ☐	**111**		**151**		
Ontario	**013** Yes ☐	**113**		**153**		
Manitoba	**015** Yes ☐	**115**		**155**		
Saskatchewan	**017** Yes ☐	**117**		**157**		
Alberta	**019** Yes ☐	**119**		**159**		
British Columbia	**021** Yes ☐	**121**		**161**		
Yukon	**023** Yes ☐	**123**		**163**		
Northwest Territories	**025** Yes ☐	**125**		**165**		
Nunavut	**026** Yes ☐	**126**		**166**		
Outside Canada	**027** Yes ☐	**127**		**167**		
Total		**129** G		**169** H		

Note 1: **Permanent establishment** is defined in subsection 400(2).
Note 2: For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If your corporation has provincial or territorial tax payable, complete Part 2.
3. If your corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

Ontario basic income tax (from Schedule 500)	270				
Ontario small business deduction (from Schedule 500)	402				
Subtotal (line 270 **minus** line 402)			▶		5A
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal (line 276 **plus** line 277)			▶		5B
Gross Ontario tax (amount 5A **plus** amount 5B)					5C
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario political contributions tax credit (from Schedule 525)	415				
Ontario non-refundable tax credits (total of lines 406 to 415)			▶		5D
Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0")					5E
Ontario research and development tax credit (from Schedule 508)				416	
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0")					5F
Ontario corporate minimum tax credit (from Schedule 510)				418	
Ontario community food program donation tax credit for farmers (from Schedule 2)				420	
Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative, enter "0")					5G
Ontario corporate minimum tax (from Schedule 510)	278	57,718			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal (line 278 **plus** line 280)		57,718	▶	57,718	5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)				57,718	5I
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	7,383			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Ontario regional opportunities investment tax credit (from Schedule 570)	472				
Ontario made manufacturing investment tax credit (from Schedule 572)	474				
Ontario refundable tax credits (total of lines 450 to 474)		7,383	▶	7,383	5J
Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets). Include this amount on line 255.				290 50,335	

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits 255 50,335

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under Regulation 1101(5q)? **101** Yes ☐ No ☒

Part 1 – Agreement between associated eligible persons or partnerships (EPOPs)

Are you associated in the tax year with one or more EPOPs with which you have entered into an agreement under subsection 1104(3.3) of the Regulations? . . . . **105** Yes ☒ No ☐

If you answered **yes**, complete Part 1. Otherwise, go to Part 2.

Enter a percentage assigned to each associated EPOP (including your corporation) as determined in the agreement.

This percentage will be used to allocate the immediate expensing limit. The total of all the percentages assigned under the agreement should not exceed 100%. If the total is more than 100%, then the associated group has an immediate expensing limit of nil. For more information about the immediate expensing limit, see note 12 in Part 2.

	1 Name of EPOP **110**	2 Identification number See **note 1** **115**	3 Percentage assigned under the agreement **120**
1.	Essex Powerlines Corporation	870066529RC0001	100.000
2.	ASI SPE 106 Inc.	809114309RC0001	
3.	EE Solar Partners Inc.	737197129RC0001	
4.	Essex Energy Corporation	870071123RC0002	
5.	Essex Power Corporation	869535435RC0001	
6.	Utilismart Corporation	864439450RC0002	
7.	Wattsworth Analysis Inc.	877468108RC0001	
		Total	100.000

Immediate expensing limit allocated to the corporation (see **note 2**) **125** 1,500,000

Note 1: The identification number is the social insurance number, business number, or partnership account number of the EPOP.

Note 2: Multiply 1.5 million by the percentage assigned to your corporation in column 3. If the total of column 3 is more than 100%, enter 0.

Part 2 – CCA calculation

	1 Class number See **note 3** 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) See **note 4** 203	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) See **note 5** 232	5 Adjustments and transfers See **note 6** 205	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition See **note 7** 221	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition See **note 8** 222	8 Proceeds of dispositions See **note 9** 207
1.	1	1908 Buildings	15,248,408						0
2.	1b	1908 - Buildings	660,039	730,341		2,513			19,998
3.	8	1915 Office Furniture & Equipment	219,017	299,999	299,999				0
4.	10	1930-1935-1940-1945	856,168	476,835	476,835				32,000
5.	12	1611 Computer Software		1,195,549	1,195,549				0
6.	14.1	1612 Land rights	87,444						0
7.	17	1955-1956 Communication Equipment - Scada	104,088						0
8.	47	18xx Distribution Plant	40,719,184	7,976,160		168,382			0
9.	50	1920 Computer Equipment	44,589	313,924	313,924				0
10.	95	2055 CIP	749,962			-124,052			0
		Totals	58,688,899	10,992,808	2,286,307	46,843			51,998

	1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) 234	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See **note 10**	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) See **note 11** 236	12 Immediate expensing See **note 12** 238	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 See **note 13** 225	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0") See **note 14**
1.	1	1908 Buildings		15,248,408					15,248,408	
2.	1b	1908 - Buildings		1,372,895			730,341	730,341	1,372,895	19,998
3.	8	1915 Office Furniture & Equipment		519,016	299,999	299,999			219,017	
4.	10	1930-1935-1940-1945		1,301,003	476,835	476,835			824,168	
5.	12	1611 Computer Software		1,195,549	1,195,549	409,242	786,307	786,307	786,307	
6.	14.1	1612 Land rights		87,444					87,444	
7.	17	1955-1956 Communication Equipment		104,088					104,088	
8.	47	18xx Distribution Plant		48,863,726			7,976,160	7,976,160	48,863,726	

	1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) 234	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See **note 10**	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) See **note 11** 236	12 Immediate expensing See **note 12** 238	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 See **note 13** 225	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0") See **note 14**
9.	50	1920 Computer Equipment		358,513	313,924	313,924			44,589	
10.	95	2055 CIP		625,910					625,910	
		Totals		69,676,552	2,286,307	1,500,000	9,492,808	9,492,808	68,176,552	19,998

Part 2 – CCA calculation (continued)

	1 Class number	Description	17 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the year (column 14 **minus** column 16) (if negative, enter "0")	18 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the year (column 17 **multiplied** by the relevant factor) See **note 15**	19 UCC adjustment for property acquired during the year other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 13 **minus** column 14 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See **note 16** **224**	20 CCA rate % See **note 17** **212**	21 Recapture of CCA See **note 18** **213**	22 Terminal loss See **note 19** **215**	23 CCA (for declining balance method, the result of column 15 **plus** column 18 **minus** column 19, **multiplied** by column 20, or a lower amount, **plus** column 12) See **note 20** **217**	24 UCC at the end of the year (column 10 **minus** column 23) **220**
1.	1	1908 Buildings				4	0	0	609,936	14,638,472
2.	1b	1908 - Buildings	710,343	355,172		6	0	0	103,684	1,269,211
3.	8	1915 Office Furniture & Equipment				20	0	0	133,803	385,213
4.	10	1930-1935-1940-1945				30	0	0	457,026	843,977
5.	12	1611 Computer Software	786,307			100	0	0	1,195,549	
6.	14.1	1612 Land rights				5	0	0	5,460	81,984
7.	17	1955-1956 Communication Equipment - Scada				8	0	0	8,327	95,761
8.	47	18xx Distribution Plant	7,976,160	3,988,080		8	0	0	4,228,144	44,635,582
9.	50	1920 Computer Equipment				55	0	0	283,511	75,002
10.	95	2055 CIP				0	0	0		625,910
		Totals	9,472,810	4,343,252					7,025,440	62,651,112

Enter the total of column 21 on line 107 of Schedule 1.
Enter the total of column 22 on line 404 of Schedule 1.
Enter the total of column 23 on line 403 of Schedule 1.

Note 3: If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101.

Note 4: Include any property acquired in previous years that has now become available for use, net of any government assistance received or entitled to be received in the year from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule. Do not include any amount in column 3 in respect of property included in column 5 (see note 6).

Note 5: A DIEP reported in column 4 is a property acquired after April 18, 2021, by a corporation that was a Canadian-controlled private corporation (CCPC) throughout the year, which became available for use in the tax year (before 2024) and was designated as such on or before the day that is 12 months after the filing-due date for the tax year to which the designation relates. It includes all capital property subject to the CCA rules, if certain conditions are met, other than property included in Classes 1 to 6, 14.1, 17, 47, 49, and 51. A property can only qualify as DIEP in the year in which it becomes available for use. See subsection 1104(3.1) of the Regulations for more information.

Note 6: Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the year for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See the T2 Corporation Income Tax Guide for other examples of adjustments and transfers to include in column 5.
Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor at least 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 7: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Part 2 – CCA calculation (continued)

Note 8: Include all amounts you have repaid during the year for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) of the Act (also known as "butterfly reorganization") or include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 9: For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).
If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a DIEP) exceeds the prescribed amount and it is disposed of to a person or partnership with which you deal at arm's length, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle. The actual cost of the vehicle will be adjusted for payment or repayment of government assistance.

Note 10: If the amount in column 5 (as shown in brackets) reduces the undepreciated capital cost, you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 11: The amount to enter in column 11 must not exceed the amount in column 10. If it does, enter in column 11 the amount from column 10. If the amount determined in column 10 is zero or a negative amount, enter zero. The only amounts incurred before April 19, 2021, to be included in this column are certain inventory purchases from arm's length persons or partnerships where the conditions in paragraphs 1100(0.3)(a) to (c) are met.

Note 12: Immediate expensing applies to a DIEP included in column 11. The total immediate expensing for the tax year (total of column 12) should not exceed the lesser of:

1. Immediate expensing limit: it is equal to one of the following five amounts, whichever is applicable:

- $1.5 million, if you are not associated with any other EPOP in the tax year
- amount from line 125, if you are associated in the tax year with one or more EPOPs
- nil, if the total of the percentages assigned in Part 1 is more than 100% or you are associated in the tax year with one or more EPOPs and have not filed an agreement in prescribed form as required under subsection 1104(3.3) of the Regulations
- the amount determined under subsection 1104(3.5) of the Regulations for any second or subsequent tax years ending in a calendar year, if you have two or more tax years ending in the calendar year in which you are associated with another EPOP that has a tax year ending in that calendar year
- any amount allocated by the minister under subsection 1104(3.4) of the Regulations

The immediate expensing limit has to be prorated if your tax year is less than 365 days. You cannot carry forward any unused amount of the immediate expensing limit.

2. UCC of the DIEP: total of column 11

You have to maintain the CCPC status throughout the relevant tax year in order to claim the immediate expensing.

Note 13: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018, and that became available for use before 2028.
Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2028.
Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that are acquired after March 1, 2020, and that became available for use before 2028.
See the T2 Corporation Income Tax Guide for more information.

Note 14: Include only elements from columns 6 and 7 that are not related to the DIEP.

Note 15: The relevant factors for property of a class in Schedule II, that is an AIIP or included in Classes 54 to 56, available for use respectively before 2024 are:

- 2 1/3 for property in Classes 43.1, 54, and 56
- 1 1/2 for property in Class 55
- 1 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, 15, and 59, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 20 for additional information) and
- 0.5 for all other property that is an AIIP

Part 2 – CCA calculation (continued)

Note 16: The UCC adjustment for property acquired during the year (also known as the half-year rule or 50% rule) does not apply to certain property (including AIIP and property included in Classes 54 to 56).
Include only elements from columns 6 and 7 that are not related to the DIEP.
For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 17: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 23.

Note 18: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 21 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a DIEP.

Note 19: If no property is left in the class at the end of the tax year and there is still a positive amount in the column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 22. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 20: If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the T2 Corporation Income Tax Guide for more information. For property in class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year. For AIIP listed below, the maximum first year allowance you can claim is determined as follows:

- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot, or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraphs 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	ASI SPE 106 Inc.		80911 4309 RC0001	3					
2.	EE Solar Partners Inc.		73719 7129 RC0001	3					
3.	Essex Energy Corporation		87007 1123 RC0002	3					
4.	Essex Power Corporation		86953 5435 RC0001	1					
5.	Utilismart Corporation		86443 9450 RC0002	3					
6.	Wattsworth Analysis Inc.		87746 8108 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.

Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Allowance for doubtful accounts	124,857		231,459	124,857	231,459
2						
	Reserves from Part 2 of Schedule 13					
	Totals	124,857		231,459	124,857	231,459

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Essex Power Corporation	2730 Highway 3 Old Castle ON CA N0R 1L0			1,366,133		

T2 SCH 14 (99)

Canada

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Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year must file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group, including those deemed to be associated under subsection 256(2) of the Income Tax Act.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless association code 5 applies)
2 – CCPC that is a **third corporation** as referred to in subsection 256(2) and has filed Schedule 28, Election not to be Associated Through a Third Corporation
3 – Non-CCPC that is a **third corporation**
4 – Associated non-CCPC
5 – Associated CCPC to which association code 1 does not apply because a **third corporation** has filed Schedule 28

Column 4: Enter the business limit for the year of each corporation in the associated group. Enter "0" if the corporation has association code 2, 3 or 4 in column 3 (except if the corporation is a cooperative or a credit union eligible for the SBD and it has association code 4).

Column 5: Assign a percentage to allocate the business limit to each corporation that has association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year the agreement applies to . . . . . . **050** Year 2023

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** ☐ Yes ☒ No

	1 Name of associated corporations **100**	2 Business number of associated corporations **200**	3 Association code **300**	4 Business limit for the year before the allocation $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	Essex Powerlines Corporation	87006 6529 RC0001	1	500,000	100.0000	500,000	
2	ASI SPE 106 Inc.	80911 4309 RC0001	1	500,000			
3	EE Solar Partners Inc.	73719 7129 RC0001	1	500,000			
4	Essex Energy Corporation	87007 1123 RC0002	1	500,000			
5	Essex Power Corporation	86953 5435 RC0001	1	500,000			
6	Utilismart Corporation	86443 9450 RC0002	1	500,000			
7	Wattsworth Analysis Inc.	87746 8108 RC0001	1	500,000			
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (C - $10,000,000). Another factor is the "adjusted aggregate investment income" from lines 744 and 745 of Schedule 7, Aggregate Investment Income and Income Eligible for the Small Business Deduction. Details of these formulas and variable C are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the lesser of: the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year.

T2 SCH 23 E (19)

Canada

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year
  - to claim a deduction against Part I tax payable
  - to claim a refund of credit earned during the current tax year
  - to claim a carryforward of credit from previous tax years
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1)
  - to request a credit carryback to one or more previous years
  - if you are subject to a recapture of ITC
- Unless otherwise stated, all legislative references are to the federal Income Tax Act and Income Tax Regulations.
- Certain ITCs are eligible for a three-year carryback (if not deductible in the year earned) and are also eligible for a twenty-year carryforward. This does not apply to the clean economy ITCs, which are refundable tax credits.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule)
    - You can no longer claim the ITC for the qualified resource property expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, Scientific Research and Experimental Development (SR&ED) Expenditures Claim
  - pre-production mining expenditures (Part 18)
    - You can no longer claim the ITC for the pre-production mining expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
  - apprenticeship job creation expenditures (Parts 19 to 21)
  - child care spaces expenditures (Part 22)
    - You can no longer claim the ITC for the child care spaces expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
- Investments or expenditures for clean economy, described in sections 127.44 or 127.45, that earn an ITC are:
  - investment in carbon capture, utilization, or storage (CCUS) projects, for qualifying expenditures made after 2021 (Part 25)
  - investment in clean technology property that is acquired and that becomes available for use after March 27, 2023 (Part 24)
- File this schedule with the T2 Corporation Income Tax Return. If you need more space, attach additional schedules.
- For more information on ITCs, see **Investment Tax Credit** in Guide T4012, T2 Corporation – Income Tax Guide.
- For more information on SR&ED, see Guide T4088, Scientific Research and Experimental Development (SR&ED) Expenditures Claim – Guide to Form T661.

Detailed information

- For the purpose of this schedule, investment means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property at the time it files the income tax return for the year in which the property was acquired. See subsection 127.44(9) for similar rules for capital cost for the CCUS ITC and subsection 127.45(5) for similar rules for capital cost for the clean technology ITC.
- An ITC deducted in a tax year for a depreciable property reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use (AFU)** before a claim for an ITC can be made. See subsections 127(11.2), 127.45(4) and 248(19) for more information. The AFU rules do not apply to claims for the CCUS ITC.
- Expenditures for SR&ED qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures. A claimant that does not meet this reporting deadline will not be able to file Schedule 508, Ontario Research and Development Tax Credit, and Schedule 566, Ontario innovation Tax Credit.
- Expenditures for an apprenticeship ITC or a clean economy ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures.

Detailed information (continued)

- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 Forms). See section 127.47 for rules that apply to partnerships for the clean economy ITCs generally. For more information on partnership allocations for CCUS ITC, see subsection 127.44(11), and for clean technology ITC, subsection 127.45(8).
- For tax purposes, Canada includes the **exclusive economic zone** of Canada as defined in the Oceans Act (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone. For the clean technology ITC, Canada includes the exclusive economic zone of Canada only for property that is described in subparagraph d(v) or (xiv) of Class 43.1 in Schedule II of the Regulations.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and new energy generation and conservation property (prescribed in Regulation 4600). Certain qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property and qualified resource property (Part 5)	
Qualified property acquired primarily for use in Atlantic Canada	10 %
Expenditures	
SR&ED (Part 11)	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15 % rate.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada	15 %
Apprenticeship job creation (Part 19)	
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
Clean economy ITCs	
To qualify for the investment tax credit rates below, corporations must elect (in prescribed form) to meet certain labour requirements – prevailing wage requirements and apprenticeship requirements. They must also attest (in prescribed form) to have met these requirements. Otherwise, the credit rate will be reduced by 10 percentage points.	
Clean technology	
If you invested in clean technology property that is acquired and that becomes available for use:	
after March 27, 2023, and before 2034	30%
after 2033 and before 2035	15%
CCUS (Part 25)	
If you incurred qualified carbon capture expenditures to capture carbon directly from ambient air:	
after 2021 and before 2031	60%
after 2030 and before 2041	30%
If you incurred qualified carbon capture expenditures to capture carbon other than directly from ambient air:	
after 2021 and before 2031	50%
after 2030 and before 2041	25%
If you incurred qualified expenditures for carbon transportation, use, or storage:	
after 2021 and before 2031	37.5%
after 2030 and before 2041	18.75 %

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

Part 2A – Determination of a qualifying corporation

This section does not apply to the clean economy investment tax credits.

Is the corporation a qualifying corporation? . . . . **101** Yes ☐ No ☒

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied) . . . . **390** ______

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if both of the following conditions are met:

- one corporation is associated with another corporation only because one or more persons own shares of the capital stock of both corporations
- one of the corporations has at least one shareholder who is not common to both corporations

If you are a **qualifying** corporation, you will earn a **100**% refund on your share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit.

Some CCPCs that are **not qualifying** corporations may also earn a **100**% refund on their share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10.

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 2B – Determination of an excluded corporation – SR&ED

Is the qualifying corporation an excluded corporation as defined under subsection 127.1(2)? . . . . **650** Yes ☐ No ☒

Only 40% refund will be available to a qualifying corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to one of the following:

a) one or more persons exempt from Part I tax under section 149
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority
c) any combination of persons referred to in a) or b) above

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . **102** Yes ☐ No ☒

If **yes**, complete Schedule 125, Income Statement Information, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . ______ x 80 % = **103** ______
Enter on line 350 of Part 8.

* Enter only contributions not already included on Form T661.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**
			Total of investments for qualified property	4A

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year 5A

Credit deemed as a remittance of co-op corporations **210**

Credit expired **215**

Subtotal (line 210 **plus** line 215) ▶ 5B

ITC at the beginning of the tax year (amount 5A **minus** amount 5B) **220**

Credit transferred on an amalgamation or the wind-up of a subsidiary **230**

ITC from repayment of assistance **235**

Qualified property (amount 4A) . . . . x 10 % = **240**

Credit allocated from a partnership **250**

Subtotal (total of lines 230 to 250) ▶ 5C

Total credit available (line 220 **plus** amount 5C) 5D

Credit deducted from Part I tax **260**

Credit carried back to previous years (amount 6A) 5E

Credit transferred to offset Part VII tax liability **280**

Subtotal (total of line 260, amount 5E, and line 280) ▶ 5F

Credit balance before refund (amount 5D **minus** amount 5F) 5G

Refund of credit claimed on investments from qualified property (from Part 7) **310**

ITC closing balance of investments from qualified property and qualified resource property
(amount 5G **minus** line 310) **320**

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	**901**
2nd previous tax year				Credit to be applied	**902**
3rd previous tax year				Credit to be applied	**903**

Total of lines 901 to 903 6A
Enter at amount 5E.

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property

Current-year ITCs (line 240 **plus** line 250 in Part 5) 7A

Credit balance before refund (from amount 5G) 7B

Refund (40 % of amount 7A or 7B, whichever is less) 7C

Enter amount 7C or a lesser amount on line 310 in Part 5 (also include in line 780 of the T2 return if you do not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Qualified SR&ED expenditures (line 559 on Form T661) . . . .

Contributions to agricultural organizations for SR&ED . . . .

Deduct:

Government assistance, non-government assistance, or contract payment . . . .

Subtotal

x 80 %

Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)* . . . . ▶ +

Qualified SR&ED expenditures (line 559 on Form T661 **plus** line 103 in Part 3)* . . . . ▶ **350**

Repayments made in the year (from line 560 on Form T661) **370**

Total qualified SR&ED expenditures (line 350 **plus** line 370) **380**

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if both of the following apply:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation
- one of the corporations has at least one shareholder who is not common to both corporations

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . **385** Yes ☐ No ☒

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete line 398.

If you answered **yes**, complete Schedule 49, Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Expenditure Limit, to determine the amounts for associated corporations.

Enter your taxable capital employed in Canada for the previous tax year 70,511,859 **minus** $10 million.
If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million **398** 40,000,000

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation

$ 40,000,000 **minus** line 398 in Part 9 . . . . 10A

Amount 10A divided by $ 40,000,000 . . . . 10B

Expenditure limit for the stand-alone corporation ($ 3,000,000 **multiplied** by amount 10B)* 10C

For an associated corporation

If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49* **400**

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount 10C or line 400 x Number of days in the tax year / 365 = 365 . . . . 10D

Your SR&ED expenditure limit for the year (enter amount 10C, line 400, or amount 10D, whichever applies) **410**

* Amount 10C or line 400 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Qualified SR&ED expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less* . . . . **420** ______ x 35 % = ______ 11A

Line 350 **minus** line 410 (if negative, enter "0") . . . . **430** ______ x 15 % = ______ 11B

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) . . . . ______

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure for a CCPC** . . . . **460** ______ x 35 % = ______ 11C

Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred before 2015 . . . **480** ______ x 20 % = ______ 11D

Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred after 2014 . . . . **490** ______ x 15 % = ______ 11E

Subtotal (total of amounts 11C to 11E) ______ ▶ ______ 11F

Current-year SR&ED ITC (total of amounts 11A, 11B, and 11F; enter on line 540 in Part 12) . . . . ______ 11G

* For corporations that are not CCPCs, enter "0" for amount 11A.

** If you were a CCPC, this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **Additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year . . . . ______ 12A

Credit deemed as a remittance of co-op corporations . . . . **510** ______

Credit expired . . . . **515** ______

Subtotal (line 510 **plus** line 515) ______ ▶ ______ 12B

ITC at the beginning of the tax year (amount 12A **minus** amount 12B) . . . . **520** ______

Credit transferred on an amalgamation or the wind-up of a subsidiary . . . . **530** ______

Total current-year credit (from amount 11G) . . . . **540** ______

Credit allocated from a partnership . . . . **550** ______

Subtotal (total of lines 530 to 550) ______ ▶ ______ 12C

Total credit available (line 520 **plus** amount 12C) . . . . ______ 12D

Credit deducted from Part I tax . . . . **560** ______

Credit carried back to previous years (amount 13A) . . . . ______ 12E

Credit transferred to offset Part VII tax liability . . . . **580** ______

Subtotal (total of line 560, amount 12E, and line 580) ______ ▶ ______ 12F

Credit balance before refund (amount 12D **minus** amount 12F) . . . . ______ 12G

Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) . . . . **610** ______

ITC closing balance on SR&ED (amount 12G **minus** line 610) . . . . **620** ______

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year Month Day			
1st previous tax year		Credit to be applied	911	
2nd previous tax year		Credit to be applied	912	
3rd previous tax year		Credit to be applied	913	

Total of lines 911 to 913 ______ 13A
Enter at amount 12E.

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part if you are a qualifying corporation as determined on line 101 in Part 2A.*

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount 11F) ______ 14A

Refundable credits (amount 14A or amount 12G, whichever is less) ______ 14B

Amount 14B or amount 11A, whichever is less ______ 14C

Net amount (amount 14B **minus** amount 14C; if negative, enter "0") ______ 14D

Amount 14D **multiplied** by 40 % ______ 14E

Amount 14C ______ 14F

Refund of ITC (amount 14E **plus** amount 14F – enter this, or a lesser amount, on line 610 in Part 12) ______ 14G

Include the total of line 310 in Part 5 and line 610 in Part 12 in line 780 of the T2 return.

* If you are also an excluded corporation, as determined in Part 2B, amount 14B must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount 14G.

Part 15 – Refund of ITC for CCPCs that are neither qualifying nor excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying corporation as determined on line 101 in Part 2A or an excluded corporation as determined on line 650 in Part 2B.

Credit balance before refund (amount 12G) ______ 15A

Refund of ITC (amount 15A or amount 11A, whichever is less) ______ 15B

Enter amount 15B, or a lesser amount, on line 610 in Part 12 and also include it in line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal Enter at amount 17A. ________ 16A

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at amount 16B.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (total of column F) Enter at amount 17B. ________ 16B

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC **760** ________
Enter at amount 17C.

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount 16A		17A
Recaptured ITC from calculation 2, amount 16B		17B
Recaptured ITC from calculation 3, line 760 in Part 16		17C
Total recapture of SR&ED investment tax credit (total of amounts 17A to 17C) Enter at amount 26A.		17D

Pre-Production Mining

Part 18 – Account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year				18A
Credit deemed as a remittance of co-op corporations	841			
Credit expired	845			
Subtotal (line 841 **plus** line 845)			►	18B
ITC at the beginning of the tax year (amount 18A **minus** amount 18B)			850	
Credit transferred on an amalgamation or the wind-up of a subsidiary			860	
Total credit available (line 850 **plus** line 860)				18C
Amount of unused credit carried forward from previous years and applied to reduce Part I tax payable in the current year			885	
ITC closing balance from pre-production mining expenditures (amount 18C **minus** line 885)			890	

Apprenticeship Job Creation

Part 19 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . **611** Yes ☐ No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages* **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**	
1.	SYS197567	Powerline Technician	92,742	9,274	2,000	
				Total current-year credit (total of column E) Enter on line 640 in Part 20.	2,000	19A

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 20 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			20A
Credit deemed as a remittance of co-op corporations **612**			
Credit expired after 20 tax years **615**			
Subtotal (line 612 **plus** line 615)		▶	20B
ITC at the beginning of the tax year (amount 20A **minus** amount 20B) **625**			
Credit transferred on an amalgamation or the wind-up of a subsidiary **630**			
ITC from repayment of assistance **635**			
Total current-year credit (amount 19A) **640**	2,000		
Credit allocated from a partnership **655**			
Subtotal (total of lines 630 to 655)	2,000	▶ 2,000	20C
Total credit available (line 625 **plus** amount 20C)		2,000	20D
Credit deducted from Part I tax **660**			
Credit carried back to previous years (amount 21A)	20E		
Subtotal (line 660 **plus** amount 20E)		▶	20F
ITC closing balance from apprenticeship job creation expenditures (amount 20D **minus** amount 20F) **690**		2,000	

Part 21 – Request for carryback of credit from apprenticeship job creation expenditures

	Year Month Day		
1st previous tax year		Credit to be applied **931**	
2nd previous tax year		Credit to be applied **932**	
3rd previous tax year		Credit to be applied **933**	

Total of lines 931 to 933 ______ 21A
Enter at amount 20E.

Child Care Spaces

Part 22 – Account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				22A
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			▶	22B
ITC at the beginning of the tax year (amount 22A **minus** amount 22B)		775		
Credit transferred on an amalgamation or the wind-up of a subsidiary	777			
Credit allocated from a partnership	782			
Subtotal (line 777 **plus** line 782)			▶	22C
Total credit available (line 775 **plus** amount 22C)				22D
Credit deducted from Part I tax		785		
ITC closing balance from child care spaces expenditures (amount 22D **minus** line 785)		790		

Recapture – Child Care Spaces

Part 23 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be added to the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property, one of the following situations takes place:

- the new child care space is no longer available
- property that was an eligible expenditure for the child care space is
  - disposed of or leased to a lessee
  - converted to another use

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . **792** ______

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . ______ 23A

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 22. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799** ______

Total recapture of child care spaces investment tax credit (total of line 792, amount 23A, and line 799) . . . ______ 23B

Enter at amount 26B.

Clean technology

Part 24 – Clean technology ITC

Clean technology ITC . . . . **155** ____________

Include in line 780 of the T2 return.

Carbon Capture, Utilization, and Storage

Part 25 – Carbon capture, utilization, and storage ITC

Carbon capture, utilization, and storage ITC . . . . **200** ____________

Include in line 780 of the T2 return.

Summary of Investment Tax Credits

Part 26 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount 17D) . . . . ____________ 26A

Recaptured child care spaces ITC (amount 23B) . . . . ____________ 26B

Total recapture of investment tax credit (amount 26A **plus** amount 26B) . . . . ____________ 26C
Enter on line 602 of the T2 return.

Part 27 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5) . . . . ____________ 27A

ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12) . . . . ____________ 27B

ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 18) . . . . ____________ 27C

ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 20) . . . . ____________ 27D

ITC from child care space expenditures deducted from Part I tax (line 785 in Part 22) . . . . ____________ 27E

Total ITC deducted from Part I tax (total of amounts 27A to 27E) . . . . ____________ 27F
Enter on line 652 of the T2 return.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
2,000				2,000

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2022-12-31				
2021-12-31				
2020-12-31				
2019-12-31				
2018-12-31				
2017-12-31				
2016-12-31				
2015-12-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				*
Total				

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 20th preceding year. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	15,772,801		
Retained earnings	104	14,289,899		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	40,398,545		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		70,461,245 ▶	70,461,245	A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

- A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
  - a) those lines applied to partnerships in the same manner that they apply to corporations, and
  - b) those amounts were computed without reference to amounts owing by the partnership
    - (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
    - (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.
- B is the partnership's deferred unrealized foreign exchange losses at the end of the period,
- C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and
- D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			70,461,245 A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)		▶	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		70,461,245

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		70,461,245 C
Deduct: Investment allowance for the year (line 490)		D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	70,461,245

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 70,461,245 x Taxable income earned in Canada **610** 1,000 / Taxable income 1,000 = **Taxable capital employed in Canada** **690** 70,461,245

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . **701** ______

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ______

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ______

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ______

Total deductions (**add** lines 711, 712, and 713) ______ ► ______ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ______

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . ______ F

Deduct: . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") ______ H

Calculation for purposes of the small business deduction (amount H x 0.225%) . . . . ______ I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount	
Due to affiliates		549,414	00
Long term debt	+	35,328,734	00
Current portion of long term debt	+	3,420,397	00
Dividends payable	+	1,100,000	00
Bank indebtedness	+		
	+		
	Total	40,398,545	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Schedule 50

Shareholder Information

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.
- Provide only one number (business number, partnership account number, social insurance number or trust number) per shareholder.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business number or partnership account number (9 digits, 2 letters, and 4 digits. If not registered, enter "**NR**") **200**	Social insurance number (9 digits) **300**	Trust number (T followed by 8 digits) **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	ESSEX POWER CORPORATION	869535435RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, General Rate Income Pool (GRIP) Calculation, or Schedule 54, Low Rate Income Pool (LRIP) Calculation, whichever is applicable.
- File the schedules with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- All legislative references are to the Income Tax Act and the Income Tax Regulations.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		1,100,000		
Total taxable dividends paid in the tax year	100	1,100,000		
Total eligible dividends paid in the tax year			150	
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	14,675,252
Excessive eligible dividend designation (line 150 **minus** line 160)				A
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			180	
Subtotal (amount A **minus** line 180)				B
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount B **multiplied** by 20 %)			190	

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	200			
Total excessive eligible dividend designations in the tax year (amount A of Schedule 54)				C
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			280	
Subtotal (amount C **minus** line 280)				D
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount D **multiplied** by 20 %)			290	

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	**112**	106,208,492
Share of total assets from partnership(s) and joint venture(s) *	**114**	
Total assets of associated corporations (amount from line 450 on Schedule 511)	**116**	54,794,043
Total assets (total of lines 112 to 116)		161,002,535
Total revenue of the corporation for the tax year **	**142**	82,465,221
Share of total revenue from partnership(s) and joint venture(s) **	**144**	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	**146**	46,352,252
Total revenue (total of lines 142 to 146)		128,817,473

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	1,633,738	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220				
Provision for deferred income taxes (debits)/cost of future income taxes	222	527,305			
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228				
Total patronage dividends received, not already included in net income/loss	232				
281	282				
283	284				
Subtotal		527,305	▶	527,305	A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320	23,357			
Provision for deferred income taxes (credits)/benefit of future income taxes	322				
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336				
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381	382				
383	384				
385	386				
387	388				
389	390				
Subtotal		23,357	▶	23,357	B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	2,137,686	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		**515**	2,137,686	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	**518**			
Adjusted CMT loss available		▶		C
Net income subject to CMT calculation (if negative, enter "0")		**520**	2,137,686	

Amount from line 520 2,137,686 x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year 365) x 4 % = ______ 1

Amount from line 520 2,137,686 x (Number of days in the tax year after June 30, 2010 365 / Number of days in the tax year 365) x 2.7 % = 57,718 2

Subtotal (amount 1 **plus** amount 2) 57,718 3

Gross CMT: amount on line 3 above x OAF **	**540**	57,718	
Deduct:			
Foreign tax credit for CMT purposes ***	**550**		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		57,718	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")		57,718	E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		215,734	G			
Deduct:						
CMT credit expired *	600					
CMT credit carryforward at the beginning of the current tax year * (see note below)		215,734	▶	620	215,734	
Add:						
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					215,734	H
Deduct:						
CMT credit deducted in the current tax year (amount P from Part 5)						I
Subtotal (amount H **minus** amount I)					215,734	J
Add:						
Net CMT payable (amount E from Part 3)		57,718				
SAT payable (amount O from Part 6 of Schedule 512)						
Subtotal		57,718	▶		57,718	K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	273,452	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					215,734	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)				1		
For a corporation that is not a life insurance corporation:						
CMT after foreign tax credit deduction (amount D from Part 3)	57,718	2				
For a life insurance corporation:						
Gross CMT (line 540 from Part 3)		3				
Gross SAT (line 460 from Part 6 of Schedule 512)		4				
The **greater** of amounts 3 and 4		5				
Deduct: line 2 or line 5, whichever applies:			57,718	6		
Subtotal (if negative, enter "0")				▶		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)						
Deduct:						
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)			7,383			
Subtotal (if negative, enter "0")				▶		O
CMT credit deducted in the current tax year (least of amounts M, N, and O)						P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	**680**
9th previous tax year	**681**
8th previous tax year	**682**
7th previous tax year	**683**
6th previous tax year	**684**
5th previous tax year	**685**
4th previous tax year	**686**
3rd previous tax year	**687**
2nd previous tax year	**688**
1st previous tax year	**689**
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . ____ Q

Deduct:

CMT loss expired * . . . . **700** ____

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ____ ▶ **720** ____

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . **750** ____

CMT loss available (line 720 **plus** line 750) . . . . ____ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . ____

Subtotal (if negative, enter "0") ____ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . **760** ____

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . **770** ____ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	ASI SPE 106 Inc.	80911 4309 RC0001	1,134,008	25,153,639
2	EE Solar Partners Inc.	73719 7129 RC0001	4,872,982	299,080
3	Essex Energy Corporation	87007 1123 RC0002	15,420,323	7,597,633
4	Essex Power Corporation	86953 5435 RC0001	25,564,212	4,723,860
5	Utilismart Corporation	86443 9450 RC0002	7,348,919	8,051,954
6	Wattsworth Analysis Inc.	87746 8108 RC0001	453,599	526,086
		Total	450 54,794,043	550 46,352,252

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2023-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information: Grace Flood

120 Telephone number including area code: (519) 737-9811

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ____________

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 1,000,000

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	University of Windsor	BAS - Electrical Engineering
2.	University of Windsor	BAS - Electrical Engineering
3.	University of Windsor	BAS - Electrical Engineering
4.		

	C Name of student **410**	D Start date of WP (see note 1 below) **430**	E End date of WP (see note 2 below) **435**
1.	Zachary Mann	2023-01-09	2023-05-05
2.	Adam Dunn	2023-05-08	2023-08-25
3.	Zachary Mann	2023-09-05	2023-12-23
4.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	13,825	25.000 %		17
2.		10.000 %	5,530	25.000 %		16
3.		10.000 %	13,899	25.000 %		15
4.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,456	3,000	3,000		3,000
2.	1,383	3,000	1,383		1,383
3.	3,475	3,000	3,000		3,000
4.					

Ontario co-operative education tax credit (total of amounts in column K) 500 7,383 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ____ x percentage on line 170 in Part 1 ____ % = ... M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Tax credits whose amount should reduce the capital cost of property

Attachment F- Detailed Calculations for Rate Term 2025-2029

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FORECAST FOR THE YEARS 2024-2029

	AccCCA not in rates	AccCCA in rates; twice legacy rule			AccCCA in rates; legacy rule (no AccCCA)	
The impact to the 1592 variance account is calculated as follows:	2024	2025	2026	2027	2028	2029
Capital Cost Allowance WITH accelerated CCA method	7,015,136	7,185,179	7,258,757	7,707,576	7,849,814	8,142,454
Capital Cost Allowance WITHOUT accelerated CCA method	6,351,992	7,185,179	7,258,757	7,707,576	7,731,003	7,946,227
Difference	663,144	-	-	-	118,811	196,227
Tax rate	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
Current tax deferred due to accelerated CCA program	175,733	-	-	-	31,485	52,000
	Due TO customers	No Adjustment	No Adjustment	No Adjustment	Due FROM customers	Due FROM customers

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2024

Capital Cost Allowance (Schedule 8) WITH adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8		Col 9
	200		**201**	**203**	**225**	**205**	**221**	**222**	**207**	**211**	
	Class Number	**Description**	**Undepreciated Capital Cost (UCC), at the beginning of the year**	**Cost of acquisitions during the year (new property must be available for use)**	**Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)**	**Adjustments and Transfers**	**Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition**	**Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition**	**Proceeds of Disposition**	**For tax years ending before November 21, 2018; 50% rule (1/2 of net acquisitions)**	**UCC (Col 2 plus Col 3 plus or minus Col 5 minus Col 8)**
1	1	1908 Buildings	$ 14,638,472	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,638,472
2	10	1930-1935-1940-1945	$ 843,977	994,000	994,000	-	-	-	-	-	1,837,977
3	8	1915 Office Furniture & Equipment	$ 385,213	225,000	225,000	-	-	-	-	-	610,213
4	17	1955-1956 Communication Equipment	$ 95,761		-	-	-	-	-	-	95,761
5	47	18xx Distribution Plant	$ 44,635,580	8,611,859	8,611,859	-	-	-	-	-	53,247,439
6	50	1920 Computer Equipment	$ 75,002		-	-	-	-	-	-	75,002
7	43.2	2075 Solar Phytovoltaic Equipment	$ -		-	-	-	-	-	-	-
8	12	1611 Computer Software	-$ 0	844,918	844,918	-	-	-	-	-	844,918
9	95	2055 CIP	$ 625,910	(545,908)	(545,908)	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	$ 81,984	70,264	70,264	-	-	-	-	-	152,248
11	16	1908 Buildings after March 2009	$ 1,269,211		-	-	-	-	-	-	1,269,211
											-
		Total	**$ 62,651,110**	**$ 10,200,133**	**$ 10,200,133**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 72,851,243**

	Col 1		Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18
	200					**224**	**212**	**213**	**215**	**217**	**220**
	Class Number	**Description**	**Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")**	**Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")**	**UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)**	**UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")**	**CCA Rate %**	**Recapture of CCA**	**Terminal loss**	**CCA for declining balance method, the result of Col 9 plus Col 12 minus Col 13, multiplied by Col 14 or a lower amount)**	**UCC at the end of the year (Col 9 minus Col 17)**
1	1	1908 Buildings	$ -	$ -	$ -	$ -	4	$ -	$ -	$ 585,539	$ 14,052,933
2	10	1930-1935-1940-1945	-	994,000	497,000	-	30	-	-	700,493	1,137,484
3	8	1915 Office Furniture & Equipment	-	225,000	112,500	-	20	-	-	144,543	465,670
4	17	1955-1956 Communication Equipment	-	-	-	-	8	-	-	7,661	88,100
5	47	18xx Distribution Plant	-	8,611,859	4,305,930	-	8	-	-	4,604,270	48,643,169
6	50	1920 Computer Equipment	-	-	-	-	55	-	-	41,251	33,751
7	43.2	2075 Solar Phytovoltaic Equipment	-	-	-	-	50	-	-	-	-
8	12	1611 Computer Software	-	844,918	-	-	100	-	-	844,918	- 0
9	95	2055 CIP	-	-	-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	-	70,264	35,132	-	5-7	-	-	10,308	141,940
11	16	1908 Buildings after March 2009	-	-	-	-	6	-	-	76,153	1,193,058
		Total	**$ -**	**$ 10,746,041**	**$ 4,950,562**	**$ -**		**$ -**	**$ -**	**$ 7,015,136**	**$ 65,836,106**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2024

Capital Cost Allowance (Schedule 8) WITHOUT adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3		Col 4			Col 5	Col 6	Col 7
	200		201	203	225	205	221	222	207	211	
	Class Number	Description	Undepreciated Capital Cost (UCC), at the beginning of the year	Cost of acquisitions during the year (new property must be available for use)	Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)	Adjustments and Transfers	Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition	Proceeds of Disposition	50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds Col 5)	Reduced undepreciated capital cost (Col 2 plus Col 3 plus or minus Col 4 minus Col 5 minus Col 6)
1	1	1908 Buildings	$ 14,638,472	$ -		$ -			$ -	$ -	$ 14,638,472
2	10	1930-1935-1940-1945	$ 1,004,627	994,000		-			-	497,000	1,501,627
3	8	1915 Office Furniture & Equipment	$ 445,213	225,000		-			-	112,500	557,713
4	17	1955-1956 Communication Equipment	$ 95,761			-			-	-	95,761
5	47	18xx Distribution Plant	$ 45,118,761	8,611,859		-			-	4,305,930	49,424,690
6	50	1920 Computer Equipment	$ 247,660			-			-	-	247,660
7	43.2	2075 Solar Phytovoltaic Equipment	$ -			-			-	-	-
8	12	1611 Computer Software	$ 597,775	844,918		-			-	422,459	1,020,234
9	95	2055 CIP	$ 625,910	(545,908)		-			-	- 272,954	352,956
10	14.1	1612 Land Rights	$ 81,984	70,264		-			-	35,132	117,116
11	1b	1908 Buildings after March 2009	$ 1,328,867			-			-	-	1,328,867
		Total	**$ 64,185,030**	**$ 10,200,133**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,100,067**	**$ 69,285,096**

	Col 1						Col 8	Col 9	Col 10	Col 11	Col 12
	200					224	212	213	215	217	220
	Class Number	Description	Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")	Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")	UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)	UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")	CCA Rate %	Recapture of CCA	Terminal loss	Capital cost allowance (for declining balance method, Col 7 multiplied by Col 8 or a lower amount)	UCC at the end of the year (Col 6 plus Col 7 minus Col 11)
1	1	1908 Buildings					4	$ -	$ -	$ 585,539	$ 14,052,933
2	10	1930-1935-1940-1945					30	-	-	450,488	1,548,139
3	8	1915 Office Furniture & Equipment					20	-	-	111,543	558,670
4	17	1955-1956 Communication Equipment					8	-	-	7,661	88,100
5	47	18xx Distribution Plant					8	-	-	3,953,975	49,776,645
6	50	1920 Computer Equipment					55	-	-	136,213	111,447
7	43.2	2075 Solar Phytovoltaic Equipment					50	-	-	-	-
8	12	1611 Computer Software					100	-	-	1,020,234	422,459
9	95	2055 CIP					-	-	-	-	80,002
10	14.1	1612 Land Rights					5-7	-	-	6,607	145,641
11	1b	1908 Buildings after March 2009					6	-	-	79,732	1,249,135
		Total	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 6,351,992**	**$ 68,033,171**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2025

Capital Cost Allowance (Schedule 8) WITH adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8		Col 9
	200		201	203	225	205	221	222	207	211	
	Class Number	Description	Undepreciated Capital Cost (UCC), at the beginning of the year	Cost of acquisitions during the year (new property must be available for use)	Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)	Adjustments and Transfers	Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition	Proceeds of Disposition	For tax years ending before November 21, 2018; 50% rule (1/2 of net acquisitions)	UCC (Col 2 plus Col 3 plus or minus Col 5 minus Col 8)
1	1	1908 Buildings	$ 14,052,933	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,052,933
2	10	1930-1935-1940-1945	$ 1,137,484	1,420,443	1,420,443	-	-	-	-	-	2,557,927
3	8	1915 Office Furniture & Equipment	$ 465,670	150,750	150,750	-	-	-	-	-	616,420
4	17	1955-1956 Communication Equipment	$ 88,100		-	-	-	-	-	-	88,100
5	47	18xx Distribution Plant	$ 48,643,169	8,622,591	8,622,591	-	-	-	-	-	57,265,760
6	50	1920 Computer Equipment	$ 33,751		-	-	-	-	-	-	33,751
7	43.2	2075 Solar Phytovoltaic Equipment	$ -		-	-	-	-	-	-	-
8	12	1611 Computer Software	-$ 0	1,042,652	1,042,652	-	-	-	-	-	1,042,652
9	95	2055 CIP	$ 80,002		-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	$ 141,940	66,416	66,416	-	-	-	-	-	208,356
11	16	1908 Buildings after March 2009	$ 1,193,058		-	-	-	-	-	-	1,193,058
											-
		Total	**$ 65,836,106**	**$ 11,302,852**	**$ 11,302,852**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 77,138,958**

	Col 1		Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18
	200					224	212	213	215	217	220
	Class Number	Description	Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")	Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")	UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)	UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")	CCA Rate %	Recapture of CCA	Terminal loss	CCA for declining balance method, the result of Col 9 plus Col 12 minus Col 13, multiplied by Col 14 or a lower amount)	UCC at the end of the year (Col 9 minus Col 17)
1	1	1908 Buildings	$ -	$ -	$ -	$ -	4	$ -	$ -	$ 562,117	$ 13,490,816
2	10	1930-1935-1940-1945	-	1,420,443	-	-	30	-	-	767,378	1,790,549
3	8	1915 Office Furniture & Equipment	-	150,750	-	-	20	-	-	123,284	493,136
4	17	1955-1956 Communication Equipment	-	-	-	-	8	-	-	7,048	81,052
5	47	18xx Distribution Plant	-	8,622,591	-	-	8	-	-	4,581,261	52,684,499
6	50	1920 Computer Equipment	-	-	-	-	55	-	-	18,563	15,188
7	43.2	2075 Solar Phytovoltaic Equipment	-	-	-	-	50	-	-	-	-
8	12	1611 Computer Software	-	1,042,652	-	-	100	-	-	1,042,652	- 0
9	95	2055 CIP	-	-	-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	-	66,416	-	-	5-7	-	-	11,293	197,063
11	16	1908 Buildings after March 2009	-	-	-	-	6	-	-	71,583	1,121,475
		Total	**$ -**	**$ 11,302,852**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 7,185,179**	**$ 69,953,780**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2025

Capital Cost Allowance (Schedule 8) WITHOUT adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3		Col 4			Col 5	Col 6	Col 7
	200		**201**	**203**	**225**	**205**	**221**	**222**	**207**	**211**	
	Class Number	**Description**	**Undepreciated Capital Cost (UCC), at the beginning of the year**	**Cost of acquisitions during the year (new property must be available for use)**	**Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)**	**Adjustments and Transfers**	**Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition**	**Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition**	**Proceeds of Disposition**	**50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds Col 5)**	**Reduced undepreciated capital cost (Col 2 plus Col 3 plus or minus Col 4 minus Col 5 minus Col 6)**
1	1	1908 Buildings	$ 14,052,933	$ -		$ -			$ -	$ -	$ 14,052,933
2	10	1930-1935-1940-1945	$ 1,548,139	1,420,443		-			-	710,222	2,258,360
3	8	1915 Office Furniture & Equipment	$ 558,670	150,750		-			-	75,375	634,045
4	17	1955-1956 Communication Equipment	$ 88,100			-			-	-	88,100
5	47	18xx Distribution Plant	$ 49,776,645	8,622,591		-			-	4,311,296	54,087,940
6	50	1920 Computer Equipment	$ 111,447			-			-	-	111,447
7	43.2	2075 Solar Phytovoltaic Equipment	$ -			-			-	-	-
8	12	1611 Computer Software	$ 422,459	1,042,652		-			-	521,326	943,785
9	95	2055 CIP	$ 80,002			-			-	-	80,002
10	14.1	1612 Land Rights	$ 145,641	66,416		-			-	33,208	178,849
11	1b	1908 Buildings after March 2009	$ 1,249,135			-			-	-	1,249,135
		Total	**$ 68,033,171**	**$ 11,302,852**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,651,426**	**$ 73,684,597**

	Col 1						Col 8	Col 9	Col 10	Col 11	Col 12
	200					**224**	**212**	**213**	**215**	**217**	**220**
	Class Number	**Description**	**Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")**	**Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")**	**UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)**	**UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")**	**CCA Rate %**	**Recapture of CCA**	**Terminal loss**	**Capital cost allowance (for declining balance method, Col 7 multiplied by Col 8 or a lower amount)**	**UCC at the end of the year (Col 6 plus Col 7 minus Col 11)**
1	1	1908 Buildings					4	$ -	$ -	$ 562,117	$ 13,490,816
2	10	1930-1935-1940-1945					30	-	-	677,508	2,291,074
3	8	1915 Office Furniture & Equipment					20	-	-	126,809	582,611
4	17	1955-1956 Communication Equipment					8	-	-	7,048	81,052
5	47	18xx Distribution Plant					8	-	-	4,327,035	54,072,201
6	50	1920 Computer Equipment					55	-	-	61,296	50,151
7	43.2	2075 Solar Phytovoltaic Equipment					50	-	-	-	-
8	12	1611 Computer Software					100	-	-	943,785	521,326
9	95	2055 CIP					-	-	-	-	80,002
10	14.1	1612 Land Rights					5-7	-	-	9,452	202,605
11	1b	1908 Buildings after March 2009					6	-	-	74,948	1,174,187
		Total	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 6,789,998**	**$ 72,546,024**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2026

Capital Cost Allowance (Schedule 8) WITH adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8		Col 9
	200		201	203	225	205	221	222	207	211	
	Class Number	**Description**	**Undepreciated Capital Cost (UCC), at the beginning of the year**	**Cost of acquisitions during the year (new property must be available for use)**	**Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)**	**Adjustments and Transfers**	**Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition**	**Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition**	**Proceeds of Disposition**	**For tax years ending before November 21, 2018; 50% rule (1/2 of net acquisitions)**	**UCC (Col 2 plus Col 3 plus or minus Col 5 minus Col 8)**
1	1	1908 Buildings	$ 13,490,816	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,490,816
2	10	1930-1935-1940-1945	$ 1,790,549	1,030,597	1,030,597	-	-	-	-	-	2,821,146
3	8	1915 Office Furniture & Equipment	$ 493,136	123,623	123,623	-	-	-	-	-	616,759
4	17	1955-1956 Communication Equipment	$ 81,052		-	-	-	-	-	-	81,052
5	47	18xx Distribution Plant	$ 52,684,499	8,539,505	8,539,505	-	-	-	-	-	61,224,004
6	50	1920 Computer Equipment	$ 15,188		-	-	-	-	-	-	15,188
7	43.2	2075 Solar Phytovoltaic Equipment	$ -		-	-	-	-	-	-	-
8	12	1611 Computer Software	-$ 0	755,415	755,415	-	-	-	-	-	755,415
9	95	2055 CIP	$ 80,002		-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	$ 197,063	69,428	69,428	-	-	-	-	-	266,491
11	16	1908 Buildings after March 2009	$ 1,121,475		-	-	-	-	-	-	1,121,475
											-
		Total	**$ 69,953,780**	**$ 10,518,568**	**$ 10,518,568**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 80,472,348**

	Col 1		Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18
	200					224	212	213	215	217	220
	Class Number	**Description**	**Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")**	**Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")**	**UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)**	**UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")**	**CCA Rate %**	**Recapture of CCA**	**Terminal loss**	**CCA for declining balance method, the result of Col 9 plus Col 12 minus Col 13, multiplied by Col 14 or a lower amount)**	**UCC at the end of the year (Col 9 minus Col 17)**
1	1	1908 Buildings	$ -	$ -	$ -	$ -	4	$ -	$ -	$ 539,633	$ 12,951,183
2	10	1930-1935-1940-1945	-	1,030,597	-	-	30	-	-	846,344	1,974,802
3	8	1915 Office Furniture & Equipment	-	123,623	-	-	20	-	-	123,352	493,407
4	17	1955-1956 Communication Equipment	-	-	-	-	8	-	-	6,484	74,568
5	47	18xx Distribution Plant	-	8,539,505	-	-	8	-	-	4,897,920	56,326,084
6	50	1920 Computer Equipment	-	-	-	-	55	-	-	8,353	6,835
7	43.2	2075 Solar Phytovoltaic Equipment	-	-	-	-	50	-	-	-	-
8	12	1611 Computer Software	-	755,415	-	-	100	-	-	755,415	- 0
9	95	2055 CIP	-	-	-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	-	69,428	-	-	5-7	-	-	13,967	252,524
11	16	1908 Buildings after March 2009	-	-	-	-	6	-	-	67,289	1,054,186
		Total	**$ -**	**$ 10,518,568**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 7,258,757**	**$ 73,213,591**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2026

Capital Cost Allowance (Schedule 8) WITHOUT adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3		Col 4			Col 5	Col 6	Col 7
	200		201	203	225	205	221	222	207	211	
	Class Number	**Description**	**Undepreciated Capital Cost (UCC), at the beginning of the year**	**Cost of acquisitions during the year (new property must be available for use)**	**Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)**	**Adjustments and Transfers**	**Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition**	**Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition**	**Proceeds of Disposition**	**50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds Col 5)**	**Reduced undepreciated capital cost (Col 2 plus Col 3 plus or minus Col 4 minus Col 5 minus Col 6)**
1	1	1908 Buildings	$ 13,490,816	$ -		$ -			$ -	$ -	$ 13,490,816
2	10	1930-1935-1940-1945	$ 2,291,074	1,030,597		-			-	515,299	2,806,372
3	8	1915 Office Furniture & Equipment	$ 582,611	123,623		-			-	61,812	644,423
4	17	1955-1956 Communication Equipment	$ 81,052			-			-	-	81,052
5	47	18xx Distribution Plant	$ 54,072,201	8,539,505		-			-	4,269,753	58,341,953
6	50	1920 Computer Equipment	$ 50,151			-			-	-	50,151
7	43.2	2075 Solar Phytovoltaic Equipment	$ -			-			-	-	-
8	12	1611 Computer Software	$ 521,326	755,415		-			-	377,708	899,033
9	95	2055 CIP	$ 80,002			-			-	-	80,002
10	14.1	1612 Land Rights	$ 202,605	69,428		-			-	34,714	237,319
11	1b	1908 Buildings after March 2009	$ 1,174,187			-			-	-	1,174,187
		Total	**$ 72,546,024**	**$ 10,518,568**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,259,284**	**$ 77,805,308**

	Col 1						Col 8	Col 9	Col 10	Col 11	Col 12
	200					224	212	213	215	217	220
	Class Number	**Description**	**Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")**	**Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")**	**UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)**	**UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")**	**CCA Rate %**	**Recapture of CCA**	**Terminal loss**	**Capital cost allowance (for declining balance method, Col 7 multiplied by Col 8 or a lower amount)**	**UCC at the end of the year (Col 6 plus Col 7 minus Col 11)**
1	1	1908 Buildings					4	$ -	$ -	$ 539,633	$ 12,951,183
2	10	1930-1935-1940-1945					30	-	-	841,912	2,479,759
3	8	1915 Office Furniture & Equipment					20	-	-	128,885	577,349
4	17	1955-1956 Communication Equipment					8	-	-	6,484	74,568
5	47	18xx Distribution Plant					8	-	-	4,667,356	57,944,350
6	50	1920 Computer Equipment					55	-	-	27,583	22,568
7	43.2	2075 Solar Phytovoltaic Equipment					50	-	-	-	-
8	12	1611 Computer Software					100	-	-	899,033	377,708
9	95	2055 CIP					-	-	-	-	80,002
10	14.1	1612 Land Rights					5-7	-	-	12,231	259,801
11	1b	1908 Buildings after March 2009					6	-	-	70,451	1,103,736
		Total	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 7,193,568**	**$ 75,871,024**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2027

Capital Cost Allowance (Schedule 8) WITH adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8		Col 9
	200		201	203	225	205	221	222	207	211	
	Class Number	Description	Undepreciated Capital Cost (UCC), at the beginning of the year	Cost of acquisitions during the year (new property must be available for use)	Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)	Adjustments and Transfers	Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition	Proceeds of Disposition	For tax years ending before November 21, 2018; 50% rule (1/2 of net acquisitions)	UCC (Col 2 plus Col 3 plus or minus Col 5 minus Col 8)
1	1	1908 Buildings	$ 12,951,183	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,951,183
2	10	1930-1935-1940-1945	$ 1,974,802	933,472	933,472	-	-	-	-	-	2,908,274
3	8	1915 Office Furniture & Equipment	$ 493,407	126,581	126,581	-	-	-	-	-	619,988
4	17	1955-1956 Communication Equipment	$ 74,568		-	-	-	-	-	-	74,568
5	47	18xx Distribution Plant	$ 56,326,084	10,969,891	10,969,891	-	-	-	-	-	67,295,975
6	50	1920 Computer Equipment	$ 6,835		-	-	-	-	-	-	6,835
7	43.2	2075 Solar Phytovoltaic Equipment	$ -		-	-	-	-	-	-	-
8	12	1611 Computer Software	-$ 0	719,513	719,513	-	-	-	-	-	719,513
9	95	2055 CIP	$ 80,002		-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	$ 252,524	73,430	73,430	-	-	-	-	-	325,954
11	16	1908 Buildings after March 2009	$ 1,054,186		-	-	-	-	-	-	1,054,186
											-
		Total	**$ 73,213,591**	**$ 12,822,887**	**$ 12,822,887**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 86,036,478**

	Col 1		Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18
	200					224	212	213	215	217	220
	Class Number	Description	Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")	Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")	UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)	UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")	CCA Rate %	Recapture of CCA	Terminal loss	CCA for declining balance method, the result of Col 9 plus Col 12 minus Col 13, multiplied by Col 14 or a lower amount)	UCC at the end of the year (Col 9 minus Col 17)
1	1	1908 Buildings	$ -	$ -	$ -	$ -	4	$ -	$ -	$ 518,047	$ 12,433,136
2	10	1930-1935-1940-1945	-	933,472	-	-	30	-	-	872,482	2,035,792
3	8	1915 Office Furniture & Equipment	-	126,581	-	-	20	-	-	123,998	495,990
4	17	1955-1956 Communication Equipment	-	-	-	-	8	-	-	5,965	68,603
5	47	18xx Distribution Plant	-	10,969,891	-	-	8	-	-	5,383,678	61,912,297
6	50	1920 Computer Equipment	-	-	-	-	55	-	-	3,759	3,076
7	43.2	2075 Solar Phytovoltaic Equipment	-	-	-	-	50	-	-	-	-
8	12	1611 Computer Software	-	719,513	-	-	100	-	-	719,513	- 0
9	95	2055 CIP	-	-	-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	-	73,430	-	-	5-7	-	-	16,883	309,070
11	16	1908 Buildings after March 2009	-	-	-	-	6	-	-	63,251	990,935
		Total	**$ -**	**$ 12,822,887**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 7,707,576**	**$ 78,328,901**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2027

Capital Cost Allowance (Schedule 8) WITHOUT adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3		Col 4			Col 5	Col 6	Col 7
	200		**201**	**203**	**225**	**205**	**221**	**222**	**207**	**211**	
	Class Number	**Description**	**Undepreciated Capital Cost (UCC), at the beginning of the year**	**Cost of acquisitions during the year (new property must be available for use)**	**Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)**	**Adjustments and Transfers**	**Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition**	**Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition**	**Proceeds of Disposition**	**50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds Col 5)**	**Reduced undepreciated capital cost (Col 2 plus Col 3 plus or minus Col 4 minus Col 5 minus Col 6)**
1	1	1908 Buildings	$ 12,951,183	$ -		$ -			$ -	$ -	$ 12,951,183
2	10	1930-1935-1940-1945	$ 2,479,759	933,472		-			-	466,736	2,946,495
3	8	1915 Office Furniture & Equipment	$ 577,349	126,581		-			-	63,291	640,640
4	17	1955-1956 Communication Equipment	$ 74,568			-			-	-	74,568
5	47	18xx Distribution Plant	$ 57,944,350	10,969,891		-			-	5,484,946	63,429,295
6	50	1920 Computer Equipment	$ 22,568			-			-	-	22,568
7	43.2	2075 Solar Phytovoltaic Equipment	$ -			-			-	-	-
8	12	1611 Computer Software	$ 377,708	719,513		-			-	359,757	737,464
9	95	2055 CIP	$ 80,002			-			-	-	80,002
10	14.1	1612 Land Rights	$ 259,801	73,430		-			-	36,715	296,516
11	1b	1908 Buildings after March 2009	$ 1,103,736			-			-	-	1,103,736
		Total	**$ 75,871,024**	**$ 12,822,887**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 6,411,444**	**$ 82,282,467**

	Col 1						Col 8	Col 9	Col 10	Col 11	Col 12
	200					**224**	**212**	**213**	**215**	**217**	**220**
	Class Number	**Description**	**Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")**	**Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")**	**UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)**	**UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")**	**CCA Rate %**	**Recapture of CCA**	**Terminal loss**	**Capital cost allowance (for declining balance method, Col 7 multiplied by Col 8 or a lower amount)**	**UCC at the end of the year (Col 6 plus Col 7 minus Col 11)**
1	1	1908 Buildings					4	$ -	$ -	$ 518,047	$ 12,433,136
2	10	1930-1935-1940-1945					30	-	-	883,948	2,529,283
3	8	1915 Office Furniture & Equipment					20	-	-	128,128	575,802
4	17	1955-1956 Communication Equipment					8	-	-	5,965	68,603
5	47	18xx Distribution Plant					8	-	-	5,074,344	63,839,897
6	50	1920 Computer Equipment					55	-	-	12,412	10,156
7	43.2	2075 Solar Phytovoltaic Equipment					50	-	-	-	-
8	12	1611 Computer Software					100	-	-	737,464	359,757
9	95	2055 CIP					-	-	-	-	80,002
10	14.1	1612 Land Rights					5-7	-	-	15,048	318,183
11	1b	1908 Buildings after March 2009					6	-	-	66,224	1,037,512
		Total	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 7,441,580**	**$ 81,252,331**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2028

Capital Cost Allowance (Schedule 8) WITH adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8		Col 9
	200		201	203	225	205	221	222	207	211	
	Class Number	Description	Undepreciated Capital Cost (UCC), at the beginning of the year	Cost of acquisitions during the year (new property must be available for use)	Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)	Adjustments and Transfers	Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition	Proceeds of Disposition	For tax years ending before November 21, 2018; 50% rule (1/2 of net acquisitions)	UCC (Col 2 plus Col 3 plus or minus Col 5 minus Col 8)
1	1	1908 Buildings	$ 12,433,136	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,433,136
2	10	1930-1935-1940-1945	$ 2,035,792	958,187	958,187	-	-	-	-	-	2,993,979
3	8	1915 Office Furniture & Equipment	$ 495,990	129,629	129,629	-	-	-	-	-	625,619
4	17	1955-1956 Communication Equipment	$ 68,603		-	-	-	-	-	-	68,603
5	47	18xx Distribution Plant	$ 61,912,297	11,130,592	11,130,592	-	-	-	-	-	73,042,889
6	50	1920 Computer Equipment	$ 3,076		-	-	-	-	-	-	3,076
7	43.2	2075 Solar Phytovoltaic Equipment	$ -		-	-	-	-	-	-	-
8	12	1611 Computer Software	-$ 0	400,255	400,255	-	-	-	-	-	400,255
9	95	2055 CIP	$ 80,002		-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	$ 309,070	57,254	57,254	-	-	-	-	-	366,324
11	16	1908 Buildings after March 2009	$ 990,935		-	-	-	-	-	-	990,935
											-
		Total	**$ 78,328,901**	**$ 12,675,917**	**$ 12,675,917**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 91,004,818**

	Col 1		Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18
	200					224	212	213	215	217	220
	Class Number	Description	Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")	Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")	UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)	UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")	CCA Rate %	Recapture of CCA	Terminal loss	CCA for declining balance method, the result of Col 9 plus Col 12 minus Col 13, multiplied by Col 14 or a lower amount)	UCC at the end of the year (Col 9 minus Col 17)
1	1	1908 Buildings	$ -	$ -	$ -	$ -	4	$ -	$ -	$ 497,325	$ 11,935,811
2	10	1930-1935-1940-1945	-	958,187	-	-	30	-	-	898,194	2,095,785
3	8	1915 Office Furniture & Equipment	-	129,629	-	-	20	-	-	125,124	500,495
4	17	1955-1956 Communication Equipment	-	-	-	-	8	-	-	5,488	63,115
5	47	18xx Distribution Plant	-	11,130,592	-	-	8	-	-	5,843,431	67,199,458
6	50	1920 Computer Equipment	-	-	-	-	55	-	-	1,692	1,384
7	43.2	2075 Solar Phytovoltaic Equipment	-	-	-	-	50	-	-	-	-
8	12	1611 Computer Software	-	400,255	-	-	100	-	-	400,255	- 0
9	95	2055 CIP	-	-	-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	-	57,254	-	-	5-7	-	-	18,849	347,475
11	16	1908 Buildings after March 2009	-	-	-	-	6	-	-	59,456	931,479
		Total	**$ -**	**$ 12,675,917**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 7,849,814**	**$ 83,155,004**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2028

Capital Cost Allowance (Schedule 8) WITHOUT adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3		Col 4			Col 5	Col 6	Col 7
	200		201	203	225	205	221	222	207	211	
	Class Number	**Description**	**Undepreciated Capital Cost (UCC), at the beginning of the year**	**Cost of acquisitions during the year (new property must be available for use)**	**Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)**	**Adjustments and Transfers**	**Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition**	**Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition**	**Proceeds of Disposition**	**50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds Col 5)**	**Reduced undepreciated capital cost (Col 2 plus Col 3 plus or minus Col 4 minus Col 5 minus Col 6)**
1	1	1908 Buildings	$ 12,433,136	$ -		$ -			$ -	$ -	$ 12,433,136
2	10	1930-1935-1940-1945	$ 2,529,283	958,187		-			-	479,094	3,008,376
3	8	1915 Office Furniture & Equipment	$ 575,802	129,629		-			-	64,815	640,617
4	17	1955-1956 Communication Equipment	$ 68,603			-			-	-	68,603
5	47	18xx Distribution Plant	$ 63,839,897	11,130,592		-			-	5,565,296	69,405,193
6	50	1920 Computer Equipment	$ 10,156			-			-	-	10,156
7	43.2	2075 Solar Phytovoltaic Equipment	$ -			-			-	-	-
8	12	1611 Computer Software	$ 359,757	400,255		-			-	200,128	559,884
9	95	2055 CIP	$ 80,002			-			-	-	80,002
10	14.1	1612 Land Rights	$ 318,183	57,254		-			-	28,627	346,810
11	1b	1908 Buildings after March 2009	$ 1,037,512			-			-	-	1,037,512
		Total	**$ 81,252,331**	**$ 12,675,917**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 6,337,959**	**$ 87,590,290**

	Col 1						Col 8	Col 9	Col 10	Col 11	Col 12
	200					224	212	213	215	217	220
	Class Number	**Description**	**Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")**	**Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")**	**UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)**	**UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")**	**CCA Rate %**	**Recapture of CCA**	**Terminal loss**	**Capital cost allowance (for declining balance method, Col 7 multiplied by Col 8 or a lower amount)**	**UCC at the end of the year (Col 6 plus Col 7 minus Col 11)**
1	1	1908 Buildings					4	$ -	$ -	$ 497,325	$ 11,935,811
2	10	1930-1935-1940-1945					30	-	-	902,513	2,584,957
3	8	1915 Office Furniture & Equipment					20	-	-	128,123	577,308
4	17	1955-1956 Communication Equipment					8	-	-	5,488	63,115
5	47	18xx Distribution Plant					8	-	-	5,552,415	69,418,074
6	50	1920 Computer Equipment					55	-	-	5,586	4,570
7	43.2	2075 Solar Phytovoltaic Equipment					50	-	-	-	-
8	12	1611 Computer Software					100	-	-	559,884	200,128
9	95	2055 CIP					-	-	-	-	80,002
10	14.1	1612 Land Rights					5-7	-	-	17,418	358,020
11	1b	1908 Buildings after March 2009					6	-	-	62,251	975,261
		Total	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 7,731,003**	**$ 86,197,246**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2029

Capital Cost Allowance (Schedule 8) WITH adoption of Accelerated CCA

Input cells

	Col 1		Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8		Col 9
	200		201	203	225	205	221	222	207	211	
	Class Number	Description	Undepreciated Capital Cost (UCC), at the beginning of the year	Cost of acquisitions during the year (new property must be available for use)	Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)	Adjustments and Transfers	Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition	Proceeds of Disposition	For tax years ending before November 21, 2018; 50% rule (1/2 of net acquisitions)	UCC (Col 2 plus Col 3 plus or minus Col 5 minus Col 8)
1	1	1908 Buildings	$ 11,935,811	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,935,811
2	10	1930-1935-1940-1945	$ 2,095,785	818,083	818,083	-	-	-	-	-	2,913,868
3	8	1915 Office Furniture & Equipment	$ 500,495	132,768	132,768	-	-	-	-	-	633,263
4	17	1955-1956 Communication Equipment	$ 63,115		-	-	-	-	-	-	63,115
5	47	18xx Distribution Plant	$ 67,199,458	11,051,447	11,051,447	-	-	-	-	-	78,250,905
6	50	1920 Computer Equipment	$ 1,384		-	-	-	-	-	-	1,384
7	43.2	2075 Solar Phytovoltaic Equipment	$ -		-	-	-	-	-	-	-
8	12	1611 Computer Software	-$ 0	321,640	321,640	-	-	-	-	-	321,640
9	95	2055 CIP	$ 80,002		-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	$ 347,475	58,812	58,812	-	-	-	-	-	406,287
11	16	1908 Buildings after March 2009	$ 931,479		-	-	-	-	-	-	931,479
											-
		Total	**$ 83,155,004**	**$ 12,382,750**	**$ 12,382,750**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 95,537,754**

	Col 1		Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18
	200					224	212	213	215	217	220
	Class Number	Description	Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")	Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")	UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)	UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")	CCA Rate %	Recapture of CCA	Terminal loss	CCA for declining balance method, the result of Col 9 plus Col 12 minus Col 13, multiplied by Col 14 or a lower amount)	UCC at the end of the year (Col 9 minus Col 17)
1	1	1908 Buildings	$ -	$ -	$ -	$ -	4	$ -	$ -	$ 477,432	$ 11,458,379
2	10	1930-1935-1940-1945	-	818,083	-	-	30	-	-	874,160	2,039,708
3	8	1915 Office Furniture & Equipment	-	132,768	-	-	20	-	-	126,653	506,610
4	17	1955-1956 Communication Equipment	-	-	-	-	8	-	-	5,049	58,066
5	47	18xx Distribution Plant	-	11,051,447	-	-	8	-	-	6,260,072	71,990,833
6	50	1920 Computer Equipment	-	-	-	-	55	-	-	761	623
7	43.2	2075 Solar Phytovoltaic Equipment	-	-	-	-	50	-	-	-	-
8	12	1611 Computer Software	-	321,640	-	-	100	-	-	321,640	- 0
9	95	2055 CIP	-	-	-	-	-	-	-	-	80,002
10	14.1	1612 Land Rights	-	58,812	-	-	5-7	-	-	20,798	385,490
11	16	1908 Buildings after March 2009	-	-	-	-	6	-	-	55,889	875,590
		Total	**$ -**	**$ 12,382,750**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 8,142,454**	**$ 87,395,300**

ESSEX POWERLINES CORPORATION
ACCELERATED INVESTMENT INCENTIVE (AII)
FOR THE YEAR ENDED DECEMBER 31, 2029

Capital Cost Allowance (Schedule 8) WITHOUT adoption of Accelerated CCA

Input cells

	Col 1 200 Class Number	Description	Col 2 201 Undepreciated Capital Cost (UCC), at the beginning of the year	Col 3 203 Cost of acquisitions during the year (new property must be available for use)	225 Cost of acquisitions from Col 3 that are accelerated investment incentive properties (AIIP)	Col 4 205 Adjustments and Transfers	221 Amount from Col 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	222 Amount from Col 5 that is repaid during the year for a property, subsequent to its disposition	Col 5 207 Proceeds of Disposition	Col 6 211 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds Col 5)	Col 7 Reduced undepreciated capital cost (Col 2 plus Col 3 plus or minus Col 4 minus Col 5 minus Col 6)
1	1	1908 Buildings	$ 11,935,811	$ -		$ -			$ -	$ -	$ 11,935,811
2	10	1930-1935-1940-1945	$ 2,584,957	818,083		-			-	409,042	2,993,998
3	8	1915 Office Furniture & Equipment	$ 577,308	132,768		-			-	66,384	643,692
4	17	1955-1956 Communication Equipment	$ 63,115			-			-	-	63,115
5	47	18xx Distribution Plant	$ 69,418,074	11,051,447		-			-	5,525,724	74,943,797
6	50	1920 Computer Equipment	$ 4,570			-			-	-	4,570
7	43.2	2075 Solar Phytovoltaic Equipment	$ -			-			-	-	-
8	12	1611 Computer Software	$ 200,128	321,640		-			-	160,820	360,948
9	95	2055 CIP	$ 80,002			-			-	-	80,002
10	14.1	1612 Land Rights	$ 358,020	58,812		-			-	29,406	387,426
11	1b	1908 Buildings after March 2009	$ 975,261			-			-	-	975,261
		Total	**$ 86,197,246**	**$ 12,382,750**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 6,191,375**	**$ 92,388,621**

	Col 1 200 Class Number	Description	Proceeds of Disposition available to reduce the UCC of AIIP (Col 8 plus Col 6 minus Col 3 plus Col 4 minus Col 7) (if negative, enter "0")	Net Capital Cost additions of AIIP acquired during the year (Col 4 minus Col 10) (if negative, enter "0")	UCC adjustment for AIIP acquired during the year (Col 11 multiplied by the relevant factor)	224 UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of Col 3 minus Col 4 minus Col 6 plus Col 7 minus Col 8) (if negative, enter "0")	Col 8 212 CCA Rate %	Col 9 213 Recapture of CCA	Col 10 215 Terminal loss	Col 11 217 Capital cost allowance (for declining balance method, Col 7 multiplied by Col 8 or a lower amount)	Col 12 220 UCC at the end of the year (Col 6 plus Col 7 minus Col 11)
1	1	1908 Buildings					4	$ -	$ -	$ 477,432	$ 11,458,379
2	10	1930-1935-1940-1945					30	-	-	898,199	2,504,841
3	8	1915 Office Furniture & Equipment					20	-	-	128,738	581,338
4	17	1955-1956 Communication Equipment					8	-	-	5,049	58,066
5	47	18xx Distribution Plant					8	-	-	5,995,504	74,474,017
6	50	1920 Computer Equipment					55	-	-	2,513	2,057
7	43.2	2075 Solar Phytovoltaic Equipment					50	-	-	-	-
8	12	1611 Computer Software					100	-	-	360,948	160,820
9	95	2055 CIP					-	-	-	-	80,002
10	14.1	1612 Land Rights					5-7	-	-	19,328	397,504
11	1b	1908 Buildings after March 2009					6	-	-	58,516	916,745
		Total	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 7,946,227**	**$ 90,633,769**

Attachment G- OEB Correspondance

ESSEX POWERLINES CORPORATION

August 8, 2023

Registrar
Ontario Energy Board
27th Floor
2300 Yonge Street
Toronto, ON
M4P 1E4

Dear Ms. Marconi,

Re: Electricity Distribution License ED-2002-0499
Z-Factor Event

Essex Powerlines Inc. (“Essex Powerlines”) is writing to advise the Ontario Energy Board (“Board”) that it experienced a Z-factor event on February 22, 2023, specifically a significant ice storm. This event was outside Essex Powerlines’ control, significantly impacted operations and resulted in Essex Powerlines incurring a material level of prudently incurred costs. This event meets the Z-factor amount eligibility criteria as set out in Section 2.6 of the *Board’s Report on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors* dated July 14, 2008 and Section 3.2.8 of the *Board’s Chapter 3 Filing Requirements for Electricity Distribution Rate Applications*, dated May 24, 2022.

Essex Powerlines will be filing a Z-factor application to recover the costs associated with the restoration of electricity service to its customers during this event, and would like to request that this Z-factor application be combined with its IRM proceeding due October 11, 2023 or in the alternative as part of it’s Cost of Service rate application due April 30, 2024.

The letter is being filed through the OEB’s RESS system.

Regards,

Joe Barile
Vice President, Regulatory and Corporate Affairs
Essex Power Corporation

c.c. John Avdoulos, President and CEO, Essex Power Corp

Attachment H- 2019 Price Cap IR Application Report

Management Action Plan – Updated November 5th, 2018

Finding No.	Finding Description	Management Action Plan	Immediate and Short Term Items Completed	Future Action Items
	Section 1 – Application of the APH, FAQ's and Other OEB Regulatory Guidelines			
1	• Lack of documented management review and/or reconciliation regarding DVA	1.1.5	• Reviewed DVA Chart of Accounts • Improved Standard Operation Procedures - new and improvement of existing, including month end journal checklist • Internalized IESO settlement responsibilities • Changed management hierarchy/reporting structure • Internal review of all draft SOPs complete • Quoting for 3rd party review of SOPs commenced	• Complete Chart of Accounts in order to ensure conformity with APH, FAQ and other Board issued guidelines (ongoing – continuous improvement); • Formalize process to review any change or modifications to DVA Chart of Accounts in order to ensure on-going compliance (ongoing – continuous improvement); • All SOPs to be reviewed by independent 3rd party (quoting commenced) and finalized; • Regularly monitor and maintain SOP's for accuracy (ongoing – continuous improvement);
2	• Historical non-compliance with APH	1.2.5	• Immediately corrected non-compliant accounts identified during the audit • Created a "draft" formal policy with respect to adding/removing general ledger accounts in order to ensure compliance with APH, FAQ and other Board issued guidelines • Finalized formal policy with respect to adding/removing general ledger accounts in order to ensure compliance with APH, FAQ and other Board issued guidelines	• Use formal policy in conjunction with Communication Plan (commitment was part of another finding below) that will ensure information related to APH, FAQ and other Board issued guidelines flows to the correct departments and people in a timely manner
3	• Late filing of 2 RRR filings	1.3.5	• Calendar of filing deadlines created in order to ensure timeliness of filings • No quarterly filing submitted late since Audit • Additional management review added per Finding one (1) above • Created "draft" SOP's related to key regulatory functions associated with quarterly/annual RRR filings • Internal review of all draft SOPs complete • Quoting for 3rd party review of SOPs commenced	• Formalize lead up process to filing date to ensure that future quarterly/annual filings are consistently made on time • All SOPs to be reviewed by independent 3rd party (quoting commenced) and finalized;

Finding No.	Finding Description	Management Action Plan	Immediate and Short Term Items Completed	Future Action Items
	Section 2 – Management Oversight and Governance Regarding DVA's			
1	• Need to strengthen Management oversight and control over regulatory activities for regulatory accounting	2.1.5	• Personnel realignment and reorganization • Succession planning underway • Maintained and expanded scope of industry peer group involvement • Staff undertook additional training, with a focus on regulatory accounting • Retained services of 3rd party (KPMG) in order to support Phase 1 and 2 of OEB Audit • Created Regulatory Staff Training Tracker with detailed listing of all training course undertaken and future courses to be attended • Completed transition of duties and responsibilities relating to IESO 1598 away from 3rd party currently undertaking same to our own internal regulatory department • Engaged industry experts to review COS application as needed • Finalize and implement Financial System Access Policy regarding financial system access permissions and ensure each existing employee is reviewed to ensure proper controlled access to regulatory books of accounts and general ledgers	• Continue work with external 3rd parties in order to review key organizational processes and controls when drafted and finalized • Make staff training an integral part of development of internal regulatory expertise – ongoing • Individual management documentation of their review of any regulatory filings – on going and as required • Review Financial System Access Policy regularly (ongoing – continuous improvement)
2	• Need to have specific audit procedures on regulatory information and accounts including DVA's by external auditors • Need to error proof all data sources and inputs to RSVA accounts	2.2.5	• Immediately directed external auditors to enhance scope of work in order to include RSVA review to ensure that testing of regulatory accounts was included • Commenced identification and error-proofing all data sources and systems • RSVA software system integration commenced	• Improve RFP for audit services to ensure proper and competent RSVA scope of review and audit of regulatory accounts • Develop automated RSVA software system that will limit manual data entry, help reduce errors and create efficiencies with respect to RSVA data sources and inputs to RSVA accounts
3	• Need to improve communication within EPLC regarding regulatory requirements	2.3.5	• Developed draft Communication Plan that details information flow within organization • Communication Plan reviewed and improved internally	• Ensure implementation, integration and finalization of Communication Plan • Ensure continuous improvement of Communications Plan
4	• Formalize management	2.4.5	• Ensured account compliance detailed in Section 1 - Finding two	• Finalize and implement change management and

Finding No.	Finding Description	Management Action Plan	Immediate and Short Term Items Completed	Future Action Items
	and approval process for regulatory accounting activities and regulatory books of accounts		(2) above • Developed draft Adding/Removing general ledger regulatory accounts policy • Developed Communication Plan	approval process policies
5	• Cross training/back up for regulatory accounting activities	2.5.5	• Personnel realignment and reorganization • Succession planning underway	• Make staff training an integral part of development of internal regulatory expertise – ongoing
6	• Control access and segregation of duties of various staff relating to regulatory books/general ledger	2.6.5	• Terminated system access for certain personnel • Developed and implemented final Financial System Access policy for formal management review and authorization of financial system access • Finalize and implement Financial System Access Policy regarding financial system access permissions and ensure each existing employee is reviewed to ensure proper controlled access to regulatory books of accounts and general ledgers	• Review Financial System Access Policy regularly (ongoing – continuous improvement)
7	• Staff risk assessment	2.7.5	• Personnel realignment and reorganization • Succession planning underway	• N/A
8	• Appropriateness of spread sheeting checks used to create DVA balances	2.8.5	• Hard coded cells were immediately removed • Commenced review of entire process leading up to and including RSVA calculation which includes detailed review of presently existing controls and enhancing and securing present visual validation checks within spreadsheets • Automation commenced	• Automating the process to reduce potential errors
9	• Insufficient safeguards or processes in place to prevent unauthorized users to access excel spreadsheets used for	2.9.5	• Access limited to RSVA files within the finance drive to only Regulatory personnel	• N/A

Finding No.	Finding Description	Management Action Plan	Immediate and Short Term Items Completed	Future Action Items
	regulatory activities			
	Section 3 – Staff Competencies and Training Regarding Regulatory Accounting			
1	• Enhancing key regulatory personnel experience and knowledge	3.1.5	• Strategic use of third party service providers to assist while internal expertise is being properly developed • Engaged industry experts throughout 2018 COS application • Quoting commenced for 3rd party service providers to review final key organizational process and controls	• Engage 3rd party service providers to review finalized key organizational process and controls
2	• Improve regulatory accounting training;	3.2.5	• Staff undertook additional training, with a focus on regulatory accounting • Staff involved in in industry peer groups • Regulatory and finance staff encouraged to take advantage of various training opportunities along with participation in various industry related groups	• Make staff training an integral part of development of internal regulatory expertise (ongoing – continuous improvement)
3	• Internalize functions/preparation of IESO Form 1598	3.3.5	• Drafted detailed IESO 1598 Filing Instructions SOP • Internalized IESO settlement responsibilities • Internal review of IESO 1598 Filing Instructions complete	• N/A
4	• Reduce dependency on consultants and third parties to meet regulatory needs	3.4.5	• Completed. Internalized regulatory accounting and reporting in-house • Implemented RSVA toolset software to better manage accounts internally	• Identify any other regulatory accounting tasks being undertaken by third parties and determine a plan to potentially internalize (ongoing – continuous improvement)
	Section 4 - Lack of Documentation for Regulatory Accounting Systems, Process, Procedures, Controls, and Oversight for DVA's			
1	• Lack of Standard Operating Procedures for key regulatory activities	• 4.1.5	• Improved Standard Operation Procedures - new and improvement of existing, including month end journal checklist • Internal review of all draft SOPs complete • Quoting for 3rd party review of SOPs commenced	• Regularly monitor and maintain SOP's for accuracy (ongoing – continuous improvement)

Finding No.	Finding Description	Management Action Plan	Immediate and Short Term Items Completed	Future Action Items
2	• Need to improve documentation that quarterly/annual RRR's to pivot table and general ledger reconciliation had been performed or reviewed	• 4.2.5	• Created Historical RRR filing workbook to help staff at all levels trend and better understand RRR data • Established RRR departmental focus groups to review, explain and detail the regulatory reporting obligations of each department • Many RRR focus groups facilitated. More to follow in 2019.	• RRR departmental focus groups establishing SOP's for majority of RRR sections

Attachment I- Details to Support Account 1592- PILS and Tax Variances

2018

CCA Class	Description	PILS CCA	PILS Accelerated CCA	Difference	Tax Rate	Account 1592
1	1908 Buildings	$748,046	$748,046	$0	26.50%	$0.00
10	1930-1935-1940-1945	$345,588	$356,742	$11,154	26.50%	$2,955.81
8	1915 Office Furniture & Equipment	$34,713	$34,713	$0	26.50%	$0.00
17	1955-1956 Communication Equipment	$12,634	$12,634	$0	26.50%	$0.00
47	18xx Distribution Plant	$2,588,998	$2,588,998	$0	26.50%	$0.00
50	1920 Computer Equipment	$165,837	$204,959	$39,122	26.50%	$10,367.33
43.2	2075 Solar Phytovoltaic Equipment	$75,285	$75,285	$0	26.50%	$0.00
12	1611 Computer Software	$207,655	$272,689	$65,034	26.50%	$17,234.01
95	2055 CIP	$0	$0	$0	26.50%	$0.00
14.1	1612 Land Rights	$7,253	$7,253	$0	26.50%	$0.00
16	1908 Buildings after March 2009	$2,244	$2,244	$0	26.50%	$0.00
	Total	**$4,188,253**	**$4,303,563**	**$115,310**		**$30,557**

2019

CCA Class	Description	PILS CCA	PILS Accelerated CCA	Difference	Tax Rate	Account 1592
1	1908 Buildings	$718,124	$718,124	$0	26.50%	$0.00
10	1930-1935-1940-1945	$303,134	$360,122	$56,988	26.50%	$15,101.82
8	1915 Office Furniture & Equipment	$32,095	$39,869	$7,774	26.50%	$2,060.11
17	1955-1956 Communication Equipment	$11,624	$11,624	$0	26.50%	$0.00
47	18xx Distribution Plant	$2,857,535	$3,245,357	$387,822	26.50%	$102,772.83
50	1920 Computer Equipment	$116,670	$180,200	$63,530	26.50%	$16,835.45
43.2	2075 Solar Phytovoltaic Equipment	$37,642	$37,642	$0	26.50%	$0.00
12	1611 Computer Software	$145,297	$274,362	$129,065	26.50%	$34,202.23
95	2055 CIP	$0	$0	$0	26.50%	$0.00
14.1	1612 Land Rights	$6,896	$6,896	$0	26.50%	$0.00
16	1908 Buildings after March 2009	$9,703	$20,402	$10,699	26.50%	$2,835.24
	Total	**$4,238,720**	**$4,894,598**	**$655,878**		**$173,808**

2020

CCA Class	Description	PILS CCA	PILS Accelerated CCA	Difference	Tax Rate	Account 1592
1	1908 Buildings	$689,399	$689,399	$0	26.50%	$0.00

10	1930-1935-1940-1945	$298,760	$449,098	$150,338	26.50%	$39,839.57
8	1915 Office Furniture & Equipment	$33,796	$45,371	$11,575	26.50%	$3,067.38
17	1955-1956 Communication Equipment	$10,694	$10,694	$0	26.50%	$0.00
47	18xx Distribution Plant	$3,035,408	$3,429,117	$393,709	26.50%	$104,332.89
50	1920 Computer Equipment	$70,924	$114,122	$43,198	26.50%	$11,447.47
43.2	2075 Solar Phytovoltaic Equipment	$18,821	$18,821	$0	26.50%	$0.00
12	1611 Computer Software	$146,359	$292,718	$146,359	26.50%	$38,785.14
95	2055 CIP	$0	$0	$0	26.50%	$0.00
14.1	1612 Land Rights	$6,661	$6,661	$0	26.50%	$0.00
16	1908 Buildings after March 2009	$14,818	$16,799	$1,981	26.50%	$524.97
	Total	**$4,325,640**	**$5,072,800**	**$747,160**		**$197,997**

2021

CCA Class	Description	PILS CCA	PILS Accelerated CCA	Difference	Tax Rate	Account 1592
1	1908 Buildings	$661,823	$661,823	$0	26.50%	$0.00
10	1930-1935-1940-1945	$304,696	$435,335	$130,639	26.50%	$34,619.34
8	1915 Office Furniture & Equipment	$46,078	$77,214	$31,136	26.50%	$8,251.04
17	1955-1956 Communication Equipment	$9,838	$9,838	$0	26.50%	$0.00
47	18xx Distribution Plant	$3,168,224	$3,588,805	$420,581	26.50%	$111,453.97
50	1920 Computer Equipment	$61,783	$125,837	$64,054	26.50%	$16,974.31
43.2	2075 Solar Phytovoltaic Equipment	$0	$0	$0	26.50%	$0.00
12	1611 Computer Software	$124,659	$249,318	$124,659	26.50%	$33,034.64
95	2055 CIP	$0	$0	$0	26.50%	$0.00
14.1	1612 Land Rights	$6,232	$6,232	$0	26.50%	$0.00
16	1908 Buildings after March 2009	$23,195	$39,983	$16,788	26.50%	$4,448.82
	Total	**$4,406,528**	**$5,194,385**	**$787,857**		**$208,782**

2022

CCA Class	Description	PILS CCA	PILS Accelerated CCA	Difference	Tax Rate	Account 1592
1	1908 Buildings	$635,350	$635,350	$0	26.50%	$0.00
10	1930-1935-1940-1945	$320,561	$482,851	$162,290	26.50%	$43,006.85
8	1915 Office Furniture & Equipment	$51,089	$60,862	$9,773	26.50%	$2,589.85
17	1955-1956 Communication Equipment	$9,051	$9,051	$0	26.50%	$0.00

47	18xx Distribution Plant	$3,327,018	$3,806,074	$479,056	26.50%	$126,949.84
50	1920 Computer Equipment	$63,040	$139,919	$76,879	26.50%	$20,372.94
43.2	2075 Solar Phytovoltaic Equipment	$0	$0	$0	26.50%	$0.00
12	1611 Computer Software	$207,526	$415,051	$207,525	26.50%	$54,994.13
95	2055 CIP	$0	$0	$0	26.50%	$0.00
14.1	1612 Land Rights	$5,833	$5,833	$0	26.50%	$0.00
16	1908 Buildings after March 2009	$35,956	$49,488	$13,532	26.50%	$3,585.98
	Total	**$4,655,424**	**$5,604,479**	**$949,055**		**$251,500**

2023

CCA Class	Description	PILS CCA	PILS Accelerated CCA	Difference	Tax Rate	Account 1592
1	1908 Buildings	$609,936	$609,936	$0	26.50%	$0.00
10	1930-1935-1940-1945	$328,376	$457,026	$128,650	26.50%	$34,092.25
8	1915 Office Furniture & Equipment	$73,803	$133,803	$60,000	26.50%	$15,900.00
17	1955-1956 Communication Equipment	$8,327	$8,327	$0	26.50%	$0.00
47	18xx Distribution Plant	$3,576,581	$4,228,144	$651,563	26.50%	$172,664.20
50	1920 Computer Equipment	$110,853	$283,511	$172,658	26.50%	$45,754.37
43.2	2075 Solar Phytovoltaic Equipment	$0	$0	$0	26.50%	$0.00
12	1611 Computer Software	$597,774	$1,195,549	$597,775	26.50%	$158,410.38
95	2055 CIP	$0	$0	$0	26.50%	$0.00
14.1	1612 Land Rights	$5,460	$5,460	$0	26.50%	$0.00
16	1908 Buildings after March 2009	$61,513	$103,684	$42,171	26.50%	$11,175.32
	Total	**$5,372,623**	**$7,025,440**	**$1,652,817**		**$437,997**