RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-1

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 2022 Electricity Distributor Rate Applications webpage.

RESPONSE:

A revised RRWF has been provided incorporating corrections or adjustments from interrogatory responses. The table below shows the interrogatory references and RRWF updates. EPI has also populated the RRWF Tab 14 with the changes.

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Interrogatory	Update identified in the response	Line on RRWF Tab 14
1-SEC-2	Appendices 2-AA, 2-AB, 2-BA - revised 2025 additions and opening 2026 balances to reflect anticipated variances in 2025 capital spending	4
2-Staff-23	Appendix 2-AB - revised response in Cell AY7 (Capital Expenditures = In Service Additions) from "Yes" to "No"	N/A
3-Staff-25	Update load forecast for 2025 actuals to date	2
3-SEC-24	Update load forecast for 2025 actuals to date and update Appendix 2-IB	2
3-VECC-13	Provide kWh, kW and customer/connection for 2025 actuals to date	2
4-VECC-23	Update Appendix 2-M for $24k in consultant costs that were inadvertently omitted from Appendix 2-M, Column B in the Application	N/A
5-Staff-38	Update for 2026 Cost of Capital parameters	3
5-VECC-29	Update average principal amount for "TD 4" facility - Appendix 2-OA and 2-OB	3
8-VECC-41	Update for 2026 preliminary UTRs	1
8-VECC-42	Update for 2026 proposed LV rates	1
Note 1	Update for 2026 Cost of Power Assumptions	1

Note 1 - EPI updated the Cost of Power assumptions to reflect the November 1, 2025 changes announced by the OEB October 17, 2025.

As a result of the above corrections or adjustments, EPI has updated and filed the following models with the interrogatory responses:

Updated Models	Explanation for Updates
EPI_IRR_2026_Rev_Reqt_Workform_1.0_20251126	Updated for corrections or adjustments as noted in table above
EPI_IRR_2026_Filing_Requirements_Chapter2_Appendices_1.0 20251126	Updated App.2-AA, 2-AB, 2-BA, 2-IB, 2-M, 2-OA, 2-OB, 2-ZA, 2-ZB
EPI_IRR_2026_CoS_Load_Forecast_Model_20251126	Updated for 2025 actuals to date
EPI_IRR_Utilis_LoadProfile_Template_20251126	Updated to reflect revised 2026 load forecast
EPI_IRR_2026_Cost_Allocation_Model_1.0_20251126	Updated for corrections or adjustments as noted in table above
EPI_IRR_2026_DVA_Continuity_Schedule_CoS_1.0_20251126	Updated billing determinants to reflect revised 2026 load forecast
EPI_IRR_2026_RTSR_Workform_1.0_EV 20251126	Updated for 2026 preliminary/proposed rates and revised 2026 load forecast
EPI_IRR_2026_Tariff_Schedule_and_Bill_Impact_Model_ENT_20251126	Updated for corrections or adjustments as noted in other updated models
EPI_IRR_2026_Tariff_Schedule_and_Bill_Impact_Model_STT_20251126	Updated for corrections or adjustments as noted in other updated models
EPI_IRR_2026_Test_year_Income_Tax_PILs_1.0_20251126	Updated for corrections or adjustments as noted in other updated models

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1-STAFF-2

Letters of Comment

Following publication of the Notice of Application, the OEB received sixty-five letters of comment. Section 2.1.7 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

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

RESPONSE:

EPI appreciates the opportunity to respond to the letters of comment submitted to the OEB regarding its 2026 Cost of Service Rate Application ("the Application") for rates effective May 1, 2026. EPI values this customer feedback and acknowledges the time and effort taken by customers to share their perspectives.

After reviewing all submissions, EPI identified five principal themes in the feedback, each of which is addressed in the sections below:

1. Affordability and Customer Impact
2. Justification of the Proposed Rate Increase
3. EPI Efficiency
4. Rate Harmonization
5. Profitability

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1. Affordability and Customer Impact

Many of the customer comments expressed concern about affordability, noting that increases in the cost of living, fixed incomes, and economic pressures make it difficult to absorb additional electricity costs. EPI recognizes these challenges and acknowledges that electricity costs contribute to broader affordability pressures faced by households.

For residential customers, the distribution component of the bill (the portion that goes to EPI) represents about 25% of the total bill. The remainder goes to pay for generation, transmission, and other costs not associated with the EPI distribution system.

EPI notes that the Application is the result of careful planning to balance customer affordability, system reliability, and public policy requirements. In August 2024, EPI engaged customers to gather input on their needs and preferences, receiving responses from 1,849 participants. Additional customer engagement took place in April 2025, focusing on the overall draft plan, projected bill impacts, and rate harmonization, as well as detailed investment trade-off scenarios. That phase received 3,845 responses. Among respondents, 78% of residential customers supported maintaining or increasing spending levels consistent with the draft plan.

To help limit cost impacts, EPI continues to pursue efficiencies and cost-saving measures. Details of these initiatives are outlined in Exhibit 1 of the Application, Section 1.9.1 (page 82). EPI's focus on cost efficiency is confirmed each year through the OEB's benchmarking of electricity distributors. This analysis estimates what a utility's total costs should be based on its operating conditions and compares actual results across the province. Since 2021, EPI's combined capital and operating costs have been at least 25% less than these forecasted levels.

EPI's proposed bill impacts in the Application on a total bill basis are less than 4% for a typical residential customer and less than 2.5% for a typical General Service <50 kW customer.

For customers most impacted, there is assistance available, including:

- **Ontario Electricity Support Program ("OESP"):** Monthly on-bill credits for qualifying low-income customers.

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- **Low-income Energy Assistance Program ("LEAP"):** One-time emergency financial support for households behind on their electricity bills.
- **Arrears Management Program:** Provides payment arrangements for customers behind on their electricity bills.

More details on these programs can be provided by the EPI Customer Service department at 1-866-804-7325, which can also connect customers with the intake agencies that administer OESP and LEAP. Additional energy-saving opportunities for households are available through the Save on Energy programs at https://www.saveonenergy.ca.

In addition, Residential and Small Business customers may choose between Time-of-Use, Ultra-Low Overnight, and Tiered price plans for the electricity they consume. These rates apply to the electricity supply portion of the bill (about 44% of the typical residential bill). As these rates relate to the supply of electricity rather than its distribution, EPI administers billing but does not set or control these prices. By choosing the rate plan that best matches their household's electricity use, customers may be able to reduce costs. More information is available on the EPI website at https://www.entegrus.com/rates.

2. Justification of the Proposed Rate Increase

Some of the customer comments questioned the need for the proposed increase and whether EPI has adequately demonstrated that it is justified.

Typically, electricity distributors file a Cost of Service application every five years. This is EPI's first such application in ten years, the last having occurred in 2016, prior to the merger of Entegrus and St. Thomas Energy Inc. Since then, distribution rates in both rate zones have increased annually at approximately the rate of inflation. While those adjustments have supported safe and reliable service, EPI now proposes a rate increase beyond inflation to maintain, modernize and expand its distribution system, as further described below.

The EPI 2026 capital and operating plan focuses on:

- Continuing to ensure the safe and reliable distribution of electricity;

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- Replacing aging infrastructure (much of it installed in the 1960's, 1970's and 1980's) in order to sustain reliability;
- Supporting customer growth and ensuring prompt system access through timely connections, targeted upgrades and planning aligned with ongoing residential and industrial development;
- Advancing system modernization and reliability through deploying operational technologies such as smart switches to mitigate outages;
- Investing in cybersecurity to protect systems and meet compliance obligations;
- Preparing for evolving customer electricity needs, such as increased electric vehicle and heat pump adoption, by upgrading at-risk transformers;
- Supporting the above evolving requirements with a modernized and expanded workforce, including investing in training and succession planning
- Enhancing the customer experience through improved digital tools and website enhancements; and,
- Managing costs prudently amid inflation and supply chain pressures.

The Application is supported by over 3,200 pages of evidence detailing system needs, cost forecasts, and customer engagement findings. It will undergo a full public review process, during which registered intervenors representing consumers and other interested parties will test the evidence before the OEB.

3. EPI Efficiency

Some customer comments sought assurance that EPI is managing costs prudently and that proposed capital and operating investments are necessary and efficient.

To help limit cost impacts, EPI continues to pursue efficiencies and cost-saving measures. Details of these initiatives are outlined in Exhibit 1 of the Application, Section 1.9.1 (page 82).
EPI's focus on cost efficiency is confirmed each year through the OEB's benchmarking of electricity distributors. This analysis estimates what a utility's total costs should be based on its operating conditions and compares actual results across the province. Since 2021, EPI's combined capital and operating costs have been at least 25% less than these forecasted levels.

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4. Profitability

Some customers commented on utility profitability and sought more information about EPI profit levels.

Regulated Ontario utilities are entitled under law to earn a fair return on investment that balances the interests of customers and shareholders while ensuring safe, reliable service. Over the past five years, Entegrus' deemed Return on Equity (ROE) averaged 9.19%, whereas its actual achieved ROE was:

- 2020 – 8.23%
- 2021 – 9.29%
- 2022 – 7.85%
- 2023 – 8.79%
- 2024 – 7.58%
- 2025 (planned) – 5.40%

These results demonstrate that Entegrus has operated within the OEB's fair-return framework. Efficiencies gained through the merger have been reinvested in utility operations.

5. Rate Harmonization

Several customers commented on the proposal to harmonize rates between the current two Entegrus rate zones, questioning the fairness of the proposed alignment.

The proposed rate harmonization would align the two current sets of distribution rates so that customers in the same rate class pay the same distribution charges, regardless of which of Entegrus' 17 communities they live in. This change promotes fairness and simplifies rate administration.

Customer engagement conducted in April 2025 indicated that 71% of residential customers either supported this rate harmonization or, did not like it but recognized it as necessary.

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Conclusion

EPI appreciates the feedback and perspectives shared by customers through the Letters of Comment. EPI remains committed to providing safe, reliable, and cost-effective service, while maintaining transparency and accountability through this OEB proceeding.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 1-SEC-1

[Exhibit 1, Attachment 1-B Business Plan]

a. Please provide all materials provided to the Entegrus Board of Directors regarding the proposed 2026 Cost of Service rate application ("Application"), that are not included in the Application.
b. Please explain any material differences between the financials shown in the Business Plan for the test year and the Application.
c. Please confirm that Entegrus' forecasted 2025 Return on Equity ("ROE") for the regulated business is 5.4%. If not confirmed, please provide an update.

RESPONSE:

a. Please see the additional materials at Attachment 1.

b. The financials shown in the Business Plan for the Test Year in the attachment are identical to those used in the Application (as shown at Exhibit 1, Attachment 1-B).

c. Confirmed.

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1-SEC-1

Attachment 1

Entegrus Powerlines Inc.
320 Queen St. (P.O. Box 70)
Chatham, ON N7M 5K2
Phone: (519) 352-6300
Toll Free: 1-866-804-7325
entegrus.com

TO: Chairman and Entegrus Powerlines Board Members

FROM: David Ferguson, Chief Regulatory Officer & VP Human Resources
Jim Hogan, President & CEO

DATE: August 1, 2025

SUBJECT: Summary of 2026 Cost of Service rate application

Purpose

While drafting of the EPI 2026 Cost of Service Rate Application (the "COS Application") is nearly complete, the authorization sought from EPI's Board of Directors is for management to finalize, execute and deliver the COS Application to the Ontario Energy Board (OEB) and do all other acts in his or her discretion that may be necessary, desirable, or useful to give effect to the authorization. This discretion may include further updates to the information herein that management may determine to be necessary or advisable, or as EPI may be advised by counsel or consultants as necessary or advisable, to give effect to this authorization, with the delivery of the COS Application, or any other act or thing by management, being conclusive evidence of such determination.

2026 COS Application Summary by Exhibit

- Recall that the last rebasing for Legacy EPI was 2016 and for STEI was 2015
- Accordingly, throughout the COS Application, the concept of "OEB Approved Proxy" is referenced, combining the Legacy 2016 OEB Approved figures and the STEI 2015 OEB Approved figures (with a small inflation adjustment to align 2015 to 2016). This proxy lets readers compare current figures against the merged utility's prior OEB approvals on a combined basis.
- The COS Application is organized into 9 exhibits.
- The following sections provide a COS Application summary by exhibit

Exhibit 1 Administration

- Exhibit 1 provides the overall application framework, corporate overview and key objectives
- Summarizes EPI's rate request, major initiatives and compliance with OEB filing requirements
- Provides audited financial statements, rating agency report and scorecard results
- Summarizes customer engagement, including customer support for the draft plan with additional investment for additional proactive replacement of the most at-risk transformers. Customers also supported rate harmonization and the extension of standby rates to St. Thomas.
- Provides key Application contacts, including Legal Counsel (BLG)

Exhibit 2 Rate Base & Distribution System Plan

- Exhibit 2 details EPI's capital investments forming the 2026 Test Year Rate Base and supports prudence and necessity of past and forecasted capital expenditures
- EPI's proposed 2026 rate base is $190.5M

TABLE 6-2: EPI'S 2026 PROPOSED RATE BASE

Line No.	Description	Amount
1	Opening Net Fixed Assets	$172,711,963
2	Closing Net Fixed Assets	$183,163,111
3	Average Net Fixed Assets	$177,937,537
4	Working Capital Allowance	$12,529,497
5	**Total Rate Base**	**$190,467,034**

- Exhibit 2 also contains the Asset Condition Assessment (ACA) and Distribution System Plan (DSP)
- The ACA work was predominantly performed in 2024 with the assistance of third-party engineering and analytics firm METSCO, based on asset management principles and processes to ensure prudent management and prioritization of asset replacement
- Based on the ACA, the DSP was created with advice and preparation assistance from Charles River & Associates. The DSP describes EPI's investment plan to sustain and modernize its distribution system from 2026-2030 while balancing affordability, reliability, and responsiveness to evolving customer needs and regulatory requirements.
- EPI's historical and forecasted capital investments are summarized as follows:

Table 3-4: Historical and Forecast Capital Expenditures ($'000s)

CATEGORY	Historical Period ($'000s)				Bridge Year	Forecast Period ($'000s)				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
System Access	$6,867	$9,910	$5,951	$5,134	$4,559	$4,890	$4,423	$4,552	$4,651	$4,752
System Renewal	$7,083	$7,080	$8,319	$10,446	$9,863	$9,656	$10,665	$10,233	$10,848	$11,320
System Service	$1,242	$901	$1,102	$1,203	$5,226	$2,245	$2,191	$2,480	$2,528	$2,419
General Plant	$1,885	$2,157	$2,398	$2,647	$3,899	$3,433	$3,034	$2,560	$2,870	$2,995
TOTAL EXPENDITURE	$17,077	$20,047	$17,770	$19,430	$23,548	$20,224	$20,313	$19,825	$20,897	$21,486
Capital Contributions	-$2,842	-$5,888	-$3,068	-$2,071	-$1,545	-$1,671	-$1,699	-$1,749	-$1,783	-$1,819
NET CAPITAL EXPENDITURES	**$14,235**	**$14,159**	**$14,702**	**$17,359**	**$22,003**	**$18,553**	**$18,614**	**$18,076**	**$19,114**	**$19,668**
System O&M	$4,628	$5,287	$5,567	$6,007	$6,404	$6,874	$7,080	$7,292	$7,511	$7,736

Note 1: The table above reflects the reclassifications of certain program types occurring in the 2026 DSP as outlined in Section 5.1.4 (refer to Table 5-26).

Note 2: Capital contributions are collected in accordance with the DSC and the provisions of its COS. In December 2024, Amendments to the DSC to Facilitate the Connection of Housing Developments and Residential (EB-2024-0092) were enacted. The amendments included the extension of the revenue horizon for residential housing developments from 25 to 40 years. This extension results in 15 more years being included in the economic evaluation process, which in turn, also reduces the amount of capital contributions that EPI will collect from customers. This change has been incorporated into this DSP.

Additional Notes re: Table 3-4

- 2025 contains the St. Thomas Edgeware TS breaker/feeder to address existing capacity constraints
- High inflation has been experienced, particularly from 2019 to 2025

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Exhibit 3 Customer and Load Forecast

- Exhibit 3 presents EPI's 2026 Test Year forecasted customer count and demand, supported by historical trends and economic factors.
- The EPI load forecast is based upon historical usage and with the use of a regression analysis and key variables, a forecast for 2026 is calculated. The process involves removing the weather variability of customers' consumption usage by weather normalizing the consumption.
- The main variables used in the EPI regression model are: (i) Weather, (ii) Days in the Month, (iii) Spring/Fall Flag, (iv) COVID Flag and (v) Manufacturing.
- The COVID Flag variable was designed to reflect the varying intensity and duration of pandemic-related disruptions such as lockdown measures and increased remote work.
- The Manufacturing variable includes forecast assumptions for 2025 and 2026 Manufacturing Sales that were initially informed by the Financial Accountability Office of Ontario's ("FAO") April 30, 2025 report entitled *The Potential Impacts of US Tariffs on the Ontario Economy,* which projects an 8% decrease in Manufacturing GDP by 2026. Following additional customer engagement results, EPI altered its intended approach and applied an adjusted decrease of 4% by 2026 to the Manufacturing variable, instead of the full 8% highlighted in the FAO Report.
- The historical and forecasted load and customer count is provided in the following table:

TABLE 3-1: SUMMARY OF LOAD AND CUSTOMER FORECAST

Year	Billed Actual (GWh)	Growth (GWh)	Billed Weather Normal (GWh)	Growth (GWh)	Customer/ Connection Count	Growth (Customer/ Connection Count)
Billed Energy (GWh) and Customer Count / Connections						
2016 OEB-approved	1227.8				76,457	
2015	1,168.0		1,176.6		75,293	
2016	1,182.9	14.8	1,168.7	(7.9)	76,604	1311
2017	1,166.4	(16.5)	1,176.7	8.0	77,012	408
2018	1,219.2	52.8	1,193.0	16.2	77,566	555
2019	1,189.2	(30.0)	1,192.6	(0.4)	78,193	627
2020	1,174.3	(15.0)	1,165.8	(26.8)	78,938	745
2021	1,213.1	38.8	1,200.5	34.7	79,946	1009
2022	1,248.6	35.6	1,242.7	42.2	81,106	1160
2023	1,223.7	(24.9)	1,254.4	11.7	82,003	897
2024	1,259.3	35.5	1,273.3	18.9	82,612	609
2025 Bridge			1,243.4	(29.9)	83,484	872
2026 Test			1,236.4	(7.0)	84,368	884

Exhibit 4 Operating Costs

- Exhibit 4 describes EPI's 2026 Test Year operations, maintenance, and administrative (OM&A) expenses, highlighting cost drivers, efficiency measures, and variances from historical spending, demonstrating alignment with business needs and regulatory expectations.

- EPI's 2026 Test Year OM&A expenses are $20.8M (excluding the Low-Income Energy Assistance Program and property taxes). The tables below present OM&A expenses from the 2016 OEB Approved Proxy through to the 2026 Test Year:

TABLE 4-2: SUMMARY OF OM&A EXPENSES - 2016 OEB APPROVED PROXY TO 2020

	Last Rebasing Year (2016 OEB Approved Proxy)	Last Rebasing Year (2016 Actuals)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals
Operations	$2,294,826	$2,304,444	$1,580,202	$1,650,977	$1,687,121	$1,796,606
Maintenance	$2,030,881	$2,026,086	$1,521,538	$1,631,316	$1,931,792	$1,664,920
Billing and Collecting	$3,550,630	$3,322,650	$3,317,066	$3,626,118	$3,322,270	$3,428,904
Community Relations	$237,844	$145,439	$175,446	$120,076	$195,772	$211,989
Administrative and General	$5,848,678	$6,780,261	$6,765,550	$6,905,539	$6,403,511	$6,473,790
Total	**$13,962,859**	**$14,578,881**	**$13,359,802**	**$13,934,027**	**$13,540,467**	**$13,576,210**
%Change (year over year)			-8.4%	4.3%	-2.8%	0.3%

TABLE 4-3: SUMMARY OF OM&A EXPENSES - 2021 TO 2026 TEST YEAR

	2021 Actuals	2022 Actuals	2023 Actuals	2024 Actuals	2025 Bridge Year	2026 Test Year
Operations	$1,840,264	$1,949,926	$2,269,855	$2,400,933	$2,560,509	$2,749,051
Maintenance	$2,093,729	$2,713,434	$2,867,273	$2,914,806	$3,107,613	$3,435,303
Billing and Collecting	$3,166,900	$3,528,878	$3,440,237	$3,724,282	$3,810,356	$4,374,049
Community Relations	$246,300	$183,373	$182,428	$177,375	$189,108	$202,964
Administrative and General	$6,438,596	$7,284,933	$7,663,670	$8,395,274	$9,343,720	$10,058,309
Total	**$13,785,790**	**$15,660,544**	**$16,423,462**	**$17,612,669**	**$19,011,306**	**$20,819,676**
%Change (year over year)	1.5%	13.6%	4.9%	7.2%	7.9%	9.5%

- As seen above, over the past decade EPI has evolved its operations in response to evolving customer expectations and legislative and regulatory requirements, including implementing digital tools and integrating of new technologies such as Distributed Energy Resources and Non-Wires Alternatives, all with strong focus on cyber security.
- Simultaneously, EPI is renewing aging infrastructure, including voltage conversions and the phased retirement of substations, to ensure that long term reliability is maintained and ongoing customer growth is accommodated
- The above evolution has been supported by a modernized workforce. To address rising service expectations and sector transformation, EPI has expanded FTEs and focused on attracting high-caliber talent with specialized expertise, while strengthening internal career development, succession planning, to maintain a strong talent pipeline for operational continuity and resilience.

- The following table provides a variance reconciliation from the 2016 OEB Approved OM&A Proxy to 2026 OM&A by costs associated with each primary driver, reflecting variations in work execution timing, shifting priorities, the launch of new initiatives, and general cost escalation.

TABLE 4-7: PRIMARY OM&A COST DRIVERS

Item	Amount
2016 OEB Approved Proxy OM&A	**$13,962,859**
Cost Drivers:	
Change in Operating Portion of Salaries, Wages, and Benefits	$5,966,898
Merger Synergies (Net of Transition Costs)	($1,817,597)
Inflation on Non-Labour Items	$2,106,479
Smart Meter Maintenance	($311,437)
Cybersecurity and Licensing Costs	$520,440
Bad Debt Expense	$257,552
Other Immaterial Items	$134,482
2026 Test Year OM&A	**$20,819,676**

Exhibit 5 Cost of Capital

- Exhibit 5 summarizes the cost of capital and capital structure as it applies to the 2026 Test Year. It compares it against the 2016 OEB Approved Proxy:

TABLE 5-4: CAPITAL STRUCTURE AND COST OF CAPITAL

Capital Structure and Cost of Capital

Year: 2026 Test Year

Particulars	Capitalization Ratio			Cost Rate	Return
	(%)		($)	(%)	($)
Debt					
Long-term Debt	56.00%		$106,661,539	4.34%	$4,629,979
Short-term Debt	4.00%	(1)	$7,618,681	3.91%	$297,890
Total Debt	60.0%		$114,280,221	4.31%	$4,927,870
Equity					
Common Equity	40.00%		$76,186,814	9.00%	$6,856,813
Preferred Shares			$ -		$ -
Total Equity	40.0%		$76,186,814	9.00%	$6,856,813
Total	100.0%		$190,467,034	6.19%	$11,784,683

Year: 2016 OEB Approved Proxy

Particulars	Capitalization Ratio			Cost Rate	Return
	(%)		($)	(%)	($)
Debt					
Long-term Debt	56.00%		$65,082,746	4.53%	$2,947,736
Short-term Debt	4.00%	(1)	$4,648,768	1.78%	$82,792
Total Debt	60.0%		$69,731,514	4.35%	$3,030,527
Equity					
Common Equity	40.00%		$46,487,676	9.22%	$4,285,347
Preferred Shares			$ -		$ -
Total Equity	40.0%		$46,487,676	9.22%	$4,285,347
Total	100.0%		$116,219,190	6.29%	$7,315,874

Additional Notes re: Table 5-4

- The long-term debt rate is an average of EPI's actual (and 2026 projected) outstanding loan instruments
- The short-term rate and common equity rate are prescribed by the OEB and may be updated in the fall of 2025 when the OEB issues new rates.

Exhibit 6 Revenue Requirement

- Exhibit 6 summarizes EPI's requested 2026 test year revenue requirement and identifies the resulting revenue deficiency.

- The revenue deficiency is calculated by comparing the 2026 Test Year revenue requirement to revenue at existing rates (based on applying existing 2025 rates to the 2026 load/customer forecast).
- EPI's Revenue Requirement consists of the following: OM&A Expenses, Property Taxes, Depreciation/Amortization Expense, PILs, and Return on Rate Base (Deemed Interest & Return on Equity).
- EPI derives its Service Revenue Requirement through distribution rates charged to its customers and Other Revenue. Other Revenue is comprised of: Miscellaneous Service Revenues, Late Payment Charges, Other Operating Revenues, and Other Income and Deductions.
- EPI has determined its allowable 2026 Net Income as $6.9M, which is a function of EPI's rate base and the OEB's deemed equity parameter. The following table details EPI's Net Income calculation for the 2026 Test Year.

TABLE 6-1: EPI'S 2026 TEST YEAR NET UTILITY INCOME

Line No.	Description	Amount
1	**Operating Revenues:**	
2	Distribution Revenue	$39,524,279
3	Other Revenue	$2,503,684
4	**Total Revenue**	**$42,027,963**
5	**Operating Expenses:**	
6	OM&A Expenses (Note 1)	$21,441,596
7	Depreciation/Amortization	$8,054,879
8	Deemed Interest Expense	$4,927,870
9	**Total Cost and Expenses**	**$34,424,345**
10	Net Income before Income Taxes	$7,603,618
11	Income Taxes (grossed-up)	$746,805
12	**Utility Net Income**	**$6,856,813**

Note 1: OM&A expenses include Property Taxes and LEAP.

- The following table shows the calculation of the 2026 Gross Revenue Deficiency of $5.8M by its components.

TABLE 6-5: REVENUE DEFICIENCY BY REVENUE REQUIREMENT COMPONENT

Line No.	Description	2016 OEB Approved Proxy	2026 Revenue at Existing Rates Allocated in Proportion to 2016 OEB Approved Proxy	2026 Test Year Revenue Requirement	Variance
		A	B	C	D = C - B
1	**Revenue Requirement:**				
2	OM&A	$13,962,859	$18,977,537	$20,819,676	$1,842,139
3	Depreciation	$4,846,465	$6,587,045	$8,054,879	$1,467,835
4	Property Tax	$347,100	$471,759	$313,730	($158,029)
5	Income Tax	$141,332	$192,090	$746,805	$554,714
6	LEAP	$32,173	$43,728	$308,190	$264,462
7	Return on Rate Base	$7,327,084	$9,958,563	$11,784,683	$1,826,120
8	**Total**	**$26,657,013**	**$36,230,722**	**$42,027,963**	**$5,797,241**
9	**Rate Base**				
10	Rate Base	$116,219,190	$116,219,190	$190,467,034	$74,247,844

Exhibit 7 Cost Allocation & Exhibit 8 Rate Design

- Exhibit 7 allocates EPI's 2026 Test Year revenue requirement to customer rate classes using OEB cost allocation policies and the 2026 Cost Allocation Model ("CA Model").
- Exhibit 8 contains EPI's proposed 2026 distribution rate design.
- EPI was assisted by consultant Utilis on cost allocation and rates matters.
- In these exhibits:
  - EPI proposes to harmonize the Legacy EPI and St. Thomas rate zones into a single tariff sheet. To support this harmonization, EPI has completed its cost allocation study on a harmonized basis and developed weighting factors to allocate costs amongst rate classes.
  - EPI is not proposing any new rate classes.
  - EPI is proposing extension of the existing Legacy EPI Large Use class rate class and Standby Rates to St. Thomas to harmonize.
  - EPI is proposing the elimination of the embedded distributor rate class (as system modifications have resulted in Hydro One no longer being embedded to EPI in Dresden).
- The following table shows EPI's revenue requirement broken down by rate class:

Table 8-2: EPI Revenue Requirement by Rate Class

Line No.	Description	Service Revenue Requirement	Allocated Other Revenue	Distribution Revenue Requirement
1	Residential	$ 26,900,516	$ 1,689,336	$ 25,211,181
2	General Service < 50 kW	$ 6,042,296	$ 305,868	$ 5,736,429
3	General Service > 50-4,999 kW	$ 7,332,430	$ 400,540	$ 6,931,890
4	Large Use	$ 1,205,606	$ 74,895	$ 1,130,711
5	Unmetered Scattered Load	$ 35,379	$ 2,117	$ 33,262
6	Sentinel Light	$ 35,367	$ 2,374	$ 32,994
7	Street Lights	$ 476,369	$ 28,556	$ 447,813
8	**Total**	**$ 42,027,963**	**$ 2,503,684**	**$ 39,524,279**

- Distribution Loss Factors represent the average electrical energy losses incurred when electricity is transmitted over a distribution network.
- EPI has calculated the total loss factor to be applied to customer's consumption based on the average wholesale and retail kWh for the years 2020 to 2024. Since EPI is partially embedded, the loss rates are calculated as a weighted average of the measurement of the metering points connected to Hydro One's distribution system, as well as the measurement of metering points where EPI is connected directly to the transmission grid.

TABLE 8-22: EPI PROPOSED LOSS FACTORS

Line No.	Description	2025 Approved		2026
		Entegrus-Main	Entegrus-STT	Proposed
1	Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0432	1.0393	1.0431
2	Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0149	-	1.0148
3	Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0328	1.0289	1.0327
4	Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0049	-	1.0048

Exhibit 9 Deferral and Variance Accounts

- Exhibit 9 details and supports EPI's Deferral and Variance Account ("DVA") balances, including proposed 2026 DVA dispositions and interest calculations.
- Group 1 DVA balances are typically disposed in annual rate applications, whereas Group 2 DVA balances are generally disposed less frequently, typically in alignment with rebasing applications
- Accordingly, the EPI disposition request is for Group 1 and Group 2 DVA balances as of December 31, 2024, with forecast Group 2 deferral balances for 2025 where applicable and forecasted interest through April 30, 2026.
- EPI proposes a net disposition recovery of $446k from customers.

TABLE 9-4: BALANCES FOR DISPOSITION

Line No.	USoA	Description	Balance at Dec 31/24	2025 Disposition	Adjustments	Interest to Apr30/26	Balance for Disposition
	GROUP 1						
1	1550	Low Voltage	$ 1,134,055	$ 695,216	$ -	$ 17,455	$ 456,295
2	1551	Smart Metering Entity Charge	$ (184,391)	$ (129,377)	$ -	$ (2,155)	$ (57,169)
3	1580	RSVA Wholesale Market	$ (1,750,074)	$ (1,409,114)	$ -	$ (16,637)	$ (357,596)
4	1580	Variance WMS – Sub-account CBR Class B	$ 615,894	$ 170,208	$ -	$ 18,521	$ 464,208
5	1584	RSVA Network	$ 2,018,588	$ 1,209,894	$ -	$ 31,663	$ 840,356
6	1586	RSVA Connection	$ 1,323,545	$ 1,004,973	$ -	$ 12,793	$ 331,365
7	1588	RSVA Power	$ 428,452	$ 221,547	$ -	$ 8,101	$ 215,007
8	1589	RSVA Global Adjustment	$ 1,045,343	$ 838,706	$ -	$ 9,134	$ 215,771
9	1595	Disposition and Recovery of Regulatory Assets	$ (17,670)	$ -	$ -	$ (686)	$ (18,356)
10		**Subtotal**	**$ 4,613,743**	**$ 2,602,052**	**$ -**	**$ 78,190**	**$ 2,089,881**
	GROUP 2						
11	1508	Other Regulatory Assets	$ 125,679	$ -	$ 403,735	$ 38,572	$ 567,986
12	1511	Incremental Cloud Computing Costs	$ 321,674	$ -	$ (20,250)	$ 12,204	$ 313,628
13	1518	RCVA Retail	$ 137,263	$ -	$ 37,594	$ 5,151	$ 180,008
14	1548	RCVA STR	$ 124,478	$ -	$ 15,244	$ 4,531	$ 144,253
15	1555	Smart Meter Capital and Recovery Offset	$ (9,205)	$ -	$ -	$ -	$ (9,205)
16	1576	CGAAP Accounting Changes	$ (95,665)	$ -	$ -	$ -	$ (95,665)
17	1592	PILs & Tax Variance	$ (4,128,039)	$ -	$ 1,482,503	$ (98,960)	$ (2,744,496)
18		**Subtotal**	**$ (3,523,815)**	**$ -**	**$ 1,918,826**	**$ (38,501)**	**$ (1,643,489)**
19		**GRAND TOTAL**	**$ 1,089,928**	**$ 2,602,052**	**$ 1,918,826**	**$ 39,689**	**$ 446,392**

Bill Impacts (from Exhibit 8)

- As of 2025, EPI has two separate rate zones: Legacy EPI and St. Thomas. The COS Application proposes the harmonization of distribution rates into one rate zone.
- The bill impacts resulting from the COS Application are shown below. Note that the 2026 bill impacts differ for the two current rate zones because the 2025 starting rates for each rate zone are different.
- The proposed bill impact for a typical Residential customer in the Legacy EPI rate zone is an approximate 3% increase and for a typical Residential customer in the St. Thomas rate zone is an approximate 4% increase.
- Based on the harmonization proposal, starting in 2026, the annual bill impacts for the applicable rate class for each of the former rate zones will be the same. This can be seen in the column titled "2026 Proposed Rates Combined" in the table below.

2026 Cost of Service Application: Draft Proposed Harmonized Bill Impacts

Line No.	Rate Class	Type	Typical kWh	Typical kW	2025 Final Rates by Rate Zone	2026 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)
1	**Entegrus - Main**							
2	Residential	RPP	750	-	$131.34	$135.42	$4.09	3.11%
3	General Service < 50 kW	RPP	2,000	-	$326.91	$334.59	$7.68	2.35%
4	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$30,182.62	$29,445.05	-$737.57	-2.44%
5	Large Use	Non-RPP	2,700,000	5,500	$451,588.06	$444,617.18	-$6,970.88	-1.54%
6	Unmetered Scattered Load	RPP	150	-	$30.37	$30.63	$0.27	0.87%
7	Sentinel Lighting	RPP	150	1	$38.10	$38.05	-$0.05	-0.13%
8	Street Lighting	Non-RPP	345,000	2,300	$76,443.68	$79,792.74	$3,349.06	4.4%
9	**Entegrus - St. Thomas**							
10	Residential	RPP	750	-	$130.03	$135.42	$5.39	4.15%
11	General Service < 50 kW	RPP	2,000	-	$328.45	$334.59	$6.14	1.87%
12	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$29,063.13	$29,445.05	$381.92	1.31%
13	Sentinel Lighting	RPP	150	1	$39.38	$38.05	-$1.33	-3.37%
14	Street Lighting	Non-RPP	345,000	2,300	$74,823.32	$79,792.74	$4,969.42	6.64%

2026-2030 BUSINESS PLAN

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2 EXECUTIVE SUMMARY

2.1 UTILITY DESCRIPTION

Entegrus Powerlines Inc. (“EPI”) operates and maintains electricity distribution systems for over 63,000 customers in Southwestern Ontario. EPI is committed to operating with local values in mind, while delivering safe, reliable, and exceptional service to our customers, partners, and communities.

The EPI service territory covers 134.5 square kilometers of urban areas, encompassed within a 5,000 square kilometer geographic area in southwestern Ontario. The company serves 63,000 customers in the following 17 communities: Blenheim, Bothwell, Chatham (including the Bloomfield Business Park), Dutton, Dresden, Erieau, Merlin, Mount Brydges, Newbury, Parkhill, Ridgetown, St. Thomas, Strathroy, Thamesville, Tilbury, Wallaceburg, Wheatley.

2.2 THE EVOLUTION OF ENTEGRUS

Chatham Hydro, founded in 1914, was the largest predecessor to what is now Entegrus Powerlines Inc (EPI). Subsequently, the evolution of EPI has been marked by the following key events:

- In 1914, Chatham Hydro, the largest predecessor, was founded.
- In 1998, Chatham-Kent Hydro (“CKH”) was formed as an amalgamation of eleven former Municipal Electric Utilities (“MEUs”). This was part of the municipal amalgamation of approximately twenty-two municipalities and townships into what is now the Municipality of Chatham-Kent.
- In 2000, CKH was incorporated under the Ontario Electricity Act
- In 2005, CKH’s parent company, the former Chatham-Kent Energy Inc. (“CK Energy”) acquired the shares of Middlesex Power Distribution Corporation (“MPDC”).
- In 2008, MPDC acquired the shares of Dutton Hydro Limited and Newbury Power Inc. and amalgamated these entities into MPDC in 2009.
- In 2011, CKH and MPDC amalgamated and rebranded as EPI.
- In 2016, the former MPDC, Dutton, and Newbury rate zones were harmonized to a single rate zone (Legacy Entegrus rate zone) as part of the EPI 2016 Cost of Service.
- In 2018, EPI and St. Thomas Energy Inc. amalgamated and continued as EPI.

EPI celebrated its 100th anniversary in 2014 and attendees at the celebration marveled at pictures demonstrating the evolution of the business and the utility sector in general. However, the pace of technological change and industry transformation over the past 10 years has been just as remarkable. Over the last decade, EPI has supported strong housing and industrial growth, particularly in St. Thomas and also in Strathroy, Mt. Brydges, and Chatham. Even during the global pandemic between 2020 and 2022, which disrupted business norms across industries, EPI effectively managed this growth and overall services. The pandemic accelerated shifts in how utilities operate (including significant retirements), spurring even more focus on digitization, “Big Data” analytics and cyber security, which are now critical aspects of modern utility management.

Simultaneously, EPI advanced its business systems and operational technologies, integrating enhanced Geographic Information Systems (“GIS”), deploying smart switches, and facilitating the emergence of Distributed Energy Resources (“DER”). These innovations commenced alongside the 2018 merger with St. Thomas Energy and have accelerated since then.

From 2019 through 2022, Entegrus experienced a period of strong growth, driven by significant residential and subdivision development in St. Thomas, Strathroy, Mt. Brydges, and Chatham. This surge in customer connections resulted in a sharp increase in System Access investment and was accompanied by rapid expansion of Fibre-to-the-Home (“FTTH”) infrastructure, as multiple Internet Service Providers undertook large-scale pole attachment projects in EPI’s larger Chatham-Kent communities. By 2023, residential growth began to moderate across most areas, a trend that has continued through 2024 and into early 2025.

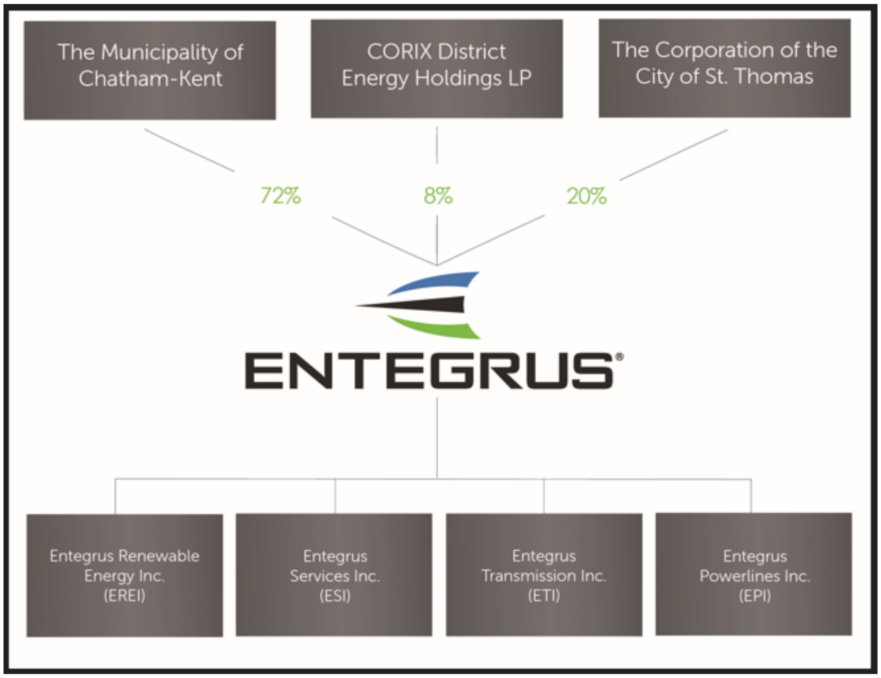
The pandemic period triggered a sustained and broad-based rise in inflation across the Canadian economy. From 2019 to 2025, the inflation factor set by the OEB for its Price Cap Incentive Rate-setting mechanism increased cumulatively by 20.7%. This reflects the broader trend of elevated inflation in Canada during the pandemic and post-pandemic period, reaching its highest levels in approximately 40 years. However, during this period, key material inputs, including transformers (100 KVA pole mount) increased by 62%, wood poles (55’ Class 2) increased by 62% and load interrupting switches increased by 54%. These values exceed the inflationary increases seen in the CPI and Price Cap Incentive Rate-setting mechanism and are a driving factor in the capital plan. EPI’s membership in Grid Smart City (a consortium of local distribution companies and non-LDC partners) has helped mitigate further impacts by facilitating purchasing consortium bulk purchases of standard equipment which allows for lower unit costs than would otherwise be available, as well as shorter lead times. EPI has consistently maintained its industry position in the 1st cohort of the OEB’s econometric Total Cost Benchmarking framework, including the last update in 2024.

The IESO’s 2025 Annual Planning Outlook, released in October 2024, forecasts a sharp 75% increase in Ontario’s electricity demand, from 144 TWh in 2023 to approximately 263 TWh by 2050, driven by industrial expansion, the electrification of transportation, and ongoing population growth. EPI has ramped its focus on system renewal, replacing aging infrastructure—much of which dates to the mid-20th century. Another key focus is on the continuation of voltage conversion, which will continue to modernize low-voltage overhead and underground systems to the more modern 27.6 kV infrastructure. This includes a dual focus on renewing aging lower-voltage systems while preparing for future load growth . Securing new and expanded energy supply sources is also vital to support growth, reliability and hardening of the grid as Ontario’s load continues to expand amid climate uncertainty.

In 2025, ongoing trade tensions and evolving tariff policies between Canada and the United States have introduced uncertainty for businesses operating in cross-border supply chains. EPI is observing early signs of impact, particularly among its industrial customers who are tied to the automotive and manufacturing sectors. Given the proximity of the EPI service territory to the U.S. border and major automotive hubs, the region is more exposed to international trade dynamics than other parts of Ontario. EPI is closely monitoring trade and tariff developments for potential effects on customer financial resilience and future load growth.

As a regulated distributor, EPI operates within a framework shaped by the Ontario Energy Board’s (“OEB”) evolving regulatory guidance during a period of significant industry transformation. Regulatory compliance remains a foundational priority, while also serving as an opportunity to ensure alignment of corporate strategy with public policy objectives. As reflected throughout this Business Plan, EPI is committed to proactive adaptation and leadership and ensuring continued reliability, enhanced customer responsiveness, as well as support for Ontario’s broader energy goals.

2.3 CORPORATE STRUCTURE



3 OUR MISSION, VISION, AND CORE VALUES

3.1 VISION, MISSION AND CORE VALUES

4 THE EPI BUSINESS PLAN STRATEGY, CORE VALUES AND THE RENEWED REGULATORY FRAMEWORK FOR ELECTRICITY

The OEB's Renewed Regulatory Framework for Electricity ("RRFE") is designed to support the cost-effective planning and operation of the distribution network. The RRFE articulates the OEB's goal for an outcomes-based approach to regulation which aligns the interests of customers and utilities.

The OEB believes that emphasizing results rather than activities better responds to customer preferences, enhances distributor productivity, and promotes innovation. There are four categories of outcomes under the RRFE: customer focus, operational effectiveness, public policy responsiveness, and financial performance.

- **Customer Focus:** services are provided in a manner that responds to identified customer preferences.
- **Operational Effectiveness**: continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives.
- **Public Policy Responsiveness**: utilities deliver on obligations mandated by the government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).
- **Financial Performance**: financial viability is maintained.

Described below is the alignment between the EPI business plan, its core values and the RRFE. EPI measures performance on its core values using the OEB's Scorecard Metrics as well as additional metrics that complement the OEB metrics. Please see Attachment 2 for the 2023 EPI Scorecard. Note that the 2024 Scorecard is still draft and will be released in Q4, 2025.

The table below provides a summary of EPI's Core Values and Corresponding Measures and how they tie into the RRFE outcomes.

EPI Core Values and Measures

LINE #	DESCRIPTION	SOURCE	TARGET
	RRFE Performance Outcome(s): Operational Effectiveness, Public Policy Responsiveness		
	EPI Core Value: SAFETY		
1	Lost Time Hours	Custom	zero
2	Level of Public Safety Awareness	Scorecard	monitor
3	Level of Compliance with O.Reg 22/04	Scorecard	C
4	Serious Electrical Incident Index: Number of Public Incidents	Scorecard	zero
5	Serious Electrical Incident Index: Rate per 1,000km of Line	Scorecard	zero
	RRFE Performance Outcome(s): Operational Effectiveness		
	EPI Core Value: INSPIRED & EMPOWERED PEOPLE		
6	Employee Satisfaction	Custom	6
	RRFE Performance Outcome(s): Customer Focus, Public Policy Responsiveness		
	EPI Core Value: CUSTOMER & COMMUNITY FOCUS		
7	New Residential/Small Commercial Services Connected on Time	Scorecard	90%
8	Scheduled Appointments Met on Time	Scorecard	90%
9	Telephone Calls Answered on Time	Scorecard	65%
10	First Contact Resolution	Scorecard	monitor
11	Billing Accuracy	Scorecard	98%
12	Customer Satisfaction	Scorecard	monitor
	RRFE Performance Outcome(s): Operational Effectiveness		
	EPI Core Value: OPERATIONAL EXCELLENCE		
13	Avg. Number of Hours Power to a Customer is Interrupted (SAIDI)	Scorecard	1.42 / 1.61
14	Avg. Number of Times Power to a Customer is Interrupted (SAIFI)	Scorecard	1.01 / 1.08
15	Customer Average Interruption Duration Index (CAIDI)	DSP	monitor
16	Momentary Average Interruption Frequency Index (MAIFI)	DSP	monitor
17	DSP Implementation Progress	Scorecard	monitor
18	Line Losses	DSP	monitor
19	Worst Performing Feeder	DSP	monitor
20	Defective Equipment Reliability	DSP	monitor
21	Efficiency Assessment	Scorecard	Tranche 2
22	Total Cost per Customer	Scorecard	monitor
23	Total Cost per km of Line	Scorecard	monitor
24	Actual vs. Predicted Econometric Total Costs	Custom	<(10%)
25	Additional Cost Metrics *	Custom	monitor
26	Poles, Towers and Fixtures Gross Capital Unit Cost	Custom	monitor
27	Transformers Gross Capital and Unit Cost	Custom	monitor
28	New Micro-Embedded Generation Facilities Connected on Time	Scorecard	90%
	RRFE Performance Outcome(s): Financial Performance		
	EPI Core Value: SUSTAINABLE GROWTH		
29	Liquidity: Current Ratio	Scorecard	monitor
30	Leverage: Total Debt to Equity Ratio	Scorecard	monitor
31	Business Plan Return on Equity	Custom	monitor
32	Regulatory Return on Equity Achieved	Scorecard	monitor
33	Customer Bill Impacts (Percentage and Dollar)	Custom	monitor

The key measures and their sources are further discussed below under their associated Core Value.

4.1 SAFETY

EPI's Core Value of Safety encompasses the OEB's RRFE outcomes of Operational Effectiveness and Public Policy Responsiveness. The Safety Core Value is defined as:

"Safety first in everything we do."

- Safety is the top priority in all work at all levels
- Be a recognized leader in Health & Safety (H&S)
- Build and maintain a best-in-class H&S culture

The electricity distribution industry has an inherently high safety risk profile, and accordingly, there is a significant degree of public policy to be adhered to in this area. EPI believes that Employee Health & Safety and Electrical Public Safety are of paramount importance. EPI seeks to instill this mindset in its employees, such that safety is an area of continuous focus.

4.1.1 APPROACH AND ACTIONS

EPI approaches Health & Safety (H&S) seriously and proactively, reinforcing safety practices regularly as a continuous area of focus. A cross-section of EPI management, including senior leadership, perform site visits at both employee and contractor sites with a "risk-based" approach in mind.

EPI requires contractors to renew their qualifications and review the EPI Safety Orientation video yearly in the Contractor Compliance program to ensure all contractors have the proper qualifications to complete the job safely. Senior staff perform site visits when crews are performing high-risk activities such as live line work. Also, more site visits are performed when contractors are present. EPI's activities target the safety of all individuals in both our communities and our company.

EPI seeks to be a recognized leader in safety. It is continually reinforced to employees, contractors, and other stakeholders that safety is our number one priority.

This mindset is reinforced by the approach and actions described in the table below, which are delineated into the following categories: Employee Safety Actions, Contractor Safety Actions, and Public Safety Actions.

<u>Safety Approach and Actions</u>

Employee Safety Actions	- Oversight by Environmental Health & Safety Committee of the EI/EPI Board of Directors, which reviews the annual safety objectives and training plans - Board committee members will perform crew visits annually. - Safety mitigation activities will be continuously monitored through the new Risk Committee of the EI/EPI boards. - An active Joint Health and Safety Committee ("JHSC"). The Joint Health and Safety Committee is comprised of representatives from all operating centers to ensure that a comprehensive and complete migration of all safety practices and procedures are effectively integrated and delivered to all staff. - EPI representation on the Ontario board of the Association of Electrical Utility Safety Professionals ("AEUSP").

	- EPI is certified by Infrastructure Health & Safety Association ("IHSA") in the Certification of Recognition ("COR") Program. EPI achieved the latest version of COR ("COR 2020") in 2024. - EPI representation with IHSA and Bolt videos. We use our trained trade staff to help create training videos to educate people about new and current best practices. - EPI supports the Apprentice Training Program through IHSA, hosted at the Chatham service center, 2-3 times per year. We assist in providing practical and theoretical training for 2nd, and 3rd year apprentice programs. - Operational safety meetings that include Field Service Reps, Metering Apprentices, Metering Technicians, Apprentice Linemen, Linemen, and Supervisors from both service centers are held daily and led by either the Operational Supervisor, Manager or Senior Manager. - Quarterly safety meetings with all operational and administrative staff are led by the Manager of Health and Safety and JHSC members. EPI implemented a safety concern program where employees bring forward safety concerns they observe daily. The program is designed to bring awareness of your work environment and to take proactive action regarding potential safety issues. - A minimum of 4 detailed worksite crew visits per month conducted by the Manager of Operations, Supervisor of Operations, Supervisor of Metering, Director of Customer Service, Director of Procurement, and Manager of Health & Safety, plus additional ad hoc site visits conducted by senior management. A JHSC member attends a minimum of 1 site visit per month. - All required staff receive annual Workplace Hazardous Materials Information System ("WHMIS") training, Workplace Violence Harassment Training, Accessibility for Ontarians with Disabilities Act ("AODA") training and Occupational Health and Safety Act training (for both the worker and the supervisor) - All Corporate, HR and H&S Polices are reviewed and revised every three years, when a new procedure is introduced, or when changes to existing ones are made. - A Health and Safety Day is held annually for all staff. Guest speakers attend to present current issues that can be experienced in the workplace. - Operational safety training throughout the year on specialized topics such as Utility Work Protection Code, EUSA Rule Book, O/H and U/G Proficiency, Confined Space, Pole Top Bucket Rescue, Bucket to Bucket Rescue, Pole Top Rescue, Confined Space Rescue, Transportation of Dangerous Goods, Forklift Training, CVOR training, Book 7, Equipotential Grounding and Bonding. - Conduct enhanced evaluations of safety incidents to ensure that any root cause problems are appropriately addressed. - In 2014 EPI partnered with the IHSA to build a training center on the EPI Chatham Service Centre yard. To date, this facility continues to enable IHSA staff to be onsite providing training to both new and existing EPI staff, while also training other utility employees and contractors in the region
Contractor Safety Actions	- Each year EPI requires its contractors to participate in a contractor management program which is administered by a third party, Contractor Compliance. This provides the company feedback on the contractor's safety program and how effectively it is working. EPI monitors this information as part of its planning process to assign work to a contractor or remove them from our list of approved contractors. Also, EPI monitors contractor safety in practice through crew visits by management or the JHSC throughout the year. - A program was established by EPI, "Electrical Safety for First Responders," to educate first responders on the best practices for coping with electrical hazards during rescue and fire situations. This program continues each year, providing refresher training to the Fire, Police and Emergency services in the EPI service territory. The program is currently being provided on site to Elgin County/St. Thomas EMS and volunteer fire departments in Chatham-Kent.

Public Safety Actions	- Throughout the year, EPI promotes public electrical safety awareness by sharing messages from ESA through traditional media and social media avenues. These messages are seasonally focused on drawing the public's attention to safety in a changing environment. - EPI employees periodically visit grade school classrooms, community colleges and career events to teach students about conservation and electrical awareness. - EPI sponsors the local Farm Safety Days in multiple communities and participated in these events in 2022 and 2023. Staff also take part in other Farm Safety Days.

4.1.2 KEY MEASURES OF PERFORMANCE DISCUSSION

To ensure Safety is a constant focus, EPI maintains its custom measure related to Employee Health & Safety, entitled: "Lost Time Hours". EPI also tracks three additional measures related to public safety.

These measures and the associated performance discussion are detailed below.

LOST TIME HOURS (CUSTOM MEASURE): TARGET = 0

Measure: Lost Time Hours	2020	2021	2022	2023	2024
Entegrus Powerlines	0	0	61.2	181.5	37.5

It is critical that EPI somehow quantify Employee Health & Safety. Accordingly, EPI tracks Lost Time Hours as the best available proxy. Lost Time Hours occur when an employee gets injured while carrying out a work task for the employer and is unable to perform the regular duties for a complete shift. EPI measures Lost Time Hours through a review of statement of claim summaries provided by the Workplace Safety and Insurance Board ("WSIB"). EPI's goal is to have zero Lost Time Hours each year.

EPI was an early utility adopter of IHSA COR certification in 2015. EPI puts significant focus on maintaining its COR certification, which drives continuous safety system and process improvement. EPI's COR-based safety process is both a commitment and an investment to keep EPI's employees safe. This should, in turn, be reflected by low Loss Time Hours.

EPI recognizes that, despite dedicated efforts to maintain the highest EH&S standards, workplace injuries may still unfortunately occur. The Lost Time Hours shown above involved an employee contracting COVID-19 (2022), an employee injured while unloading a truck (2023), and an employee colliding with a door frame (2024). Post recovery, these employees were able to resume full duties. Following these incidents, management conducted reviews and implemented additional corrective actions, where necessary, to further enhance employee safety. This contributed to the decision to implement the next stage of COR certification (the COR 2020 accreditation) in 2024.

Moving forward, EPI will continue to maintain its COR certification. This included achieving the implementation of the newest COR 2020 accreditation in 2024, with an overall score of 88%.

LEVEL OF PUBLIC SAFETY AWARENESS (SCORECARD MEASURE): MONITOR

Measure: Level of Public Safety Awareness	2020	2021	2022	2023	2024
Entegrus Powerlines	81%	78%	78%	79%	79%

In 2015, the OEB (in consultation with the ESA) released three new industry measures related to distributor electrical safety. The first metric, Level of Public Safety Awareness measures the level of awareness of key electrical safety precautions amongst the public residing within an electricity distributor's service territory. This survey is done biennially, using standardized questions across the industry. Accordingly, the survey results will always be the same for two consecutive years. The most recent survey was conducted in 2024, and the next survey will be conducted in the spring of 2026 (for 2025 and 2026 results).

Moving forward, EPI will continue to conduct community safety awareness campaigns and will continue to reinforce public safety messaging through media and advertising channels.

LEVEL OF COMPLIANCE WITH ONTARIO REGULATION 22/04 (SCORECARD MEASURE): TARGET = C

Measure: Level of Compliance with Ontario Regulations 22/04	2020	2021	2022	2023	2024
Entegrus Powerlines	C	C	C	C	C

Another industry safety metric originally released in 2015 by the OEB (in consultation with the ESA) relates to compliance with the Electrical Distribution Safety Regulation (Ontario Regulation 22/04, or the "O. Reg 22/04"). O.Reg 22/04 establishes a standard for safety performance and offers distribution companies options for achieving compliance. Specifically, the Regulation requires the approval of equipment, plans, specifications, and inspection of construction before they are put into service. A consultant engaged by the ESA conducts annual audits of each distributor's compliance with the Regulation. Audit results are assessed according to the following outcomes:

- Non-Compliance ("NC"): A failure to comply with a substantial part of the Regulation; or continuing failure to comply with a previously identified "Needs Improvement" item.
- Needs Improvement ("NI"): A failure to fully comply with part of the Regulation; or non-pervasive failure to comply with adequate, established procedures for complying with the Regulation.
- Compliant ("C"): Substantially meeting the requirements of the Regulation.

As noted above, EPI has established a strong track record of compliance with Electrical Distribution Safety Regulation. Moving forward, EPI will continue to reinforce engineering standards compliance, ensuring that its engineering processes are compliant with O. Reg 22/04. EPI's goal will continue to be assessed as Compliant.

SERIOUS ELECTRICAL INCIDENT INDEX (SCORECARD MEASURE): TARGET = 0

Measure: Serious Electrical Incident Index		2020	2021	2022	2023	2024
Entegrus Powerlines	Number of General Public Incidents	4	1	1	0	0
	Rate per 1,000km of line	1.297	0.329	0.311	0.00	0.00

The third public safety measure released by the OEB (in consultation with the ESA) in 2015 relates to the Serious Electrical Incident Index. This is measured as the number and percentage of non-occupational (general public) serious electrical incidents occurring on EPI's distribution system per 1,000km of line.

There were no serious electrical incidents in 2023 or 2024. From 2020 to 2022, incidents included weather-related vegetation contacts breaking conductor phases, a large tree falling and breaking two phases of a three-phase line and a member of the public making contract with a distribution line while tree-trimming. Fortunately, there were no reported injuries during these incidents. Following these incidents, management conducted reviews and implemented additional corrective actions, where necessary, to further enhance public safety.

These incidents confirmed the need to continue focusing on contractor and first responder safety training, organize classroom visits to educate children about electrical safety, and public safety awareness and electrical safety communications.

Moving forward, EPI will continue to share public safety awareness and electrical safety awareness messages and learnings, by continuing to conduct contractor and first responder electrical safety training, as well as visits to classrooms to educate children about electrical safety.

4.1.3 SAFETY – BUSINESS PLAN GOALS MOVING FORWARD

EPI is committed to continuously improving its safety processes to maintain a safe and healthy environment for employees and the public. EPI's achievement and maintenance of IHSA COR certification will continue to set a high bar for EPI health & safety, as well as drive continuous improvement.

Continuous improvement of the safety program includes more than just a strong management system of operational and administrative policies and controls around safety. An evolutionary path to view safety in is the context of Human Organizational Performance ("HOP") where the task, environment, and employee dynamic are managed within a team. A full understanding of duties and responsibilities in each position is critical to ensuring that within a team, the HOP experience will include self-direction of safety. A formalization of the safety practices that tend to naturally exist will be implemented. In 2018, EPI rolled out a Health and Safety Policy called the Internal Responsibility System ("IRS"). The IRS is based on the principle that safety is the responsibility of everyone, and each person needs to do their part in accordance with the IRS. The IRS has been integrated into EPI's safety culture and reinforced with employee education, training, and review in our goal of achieving a true HOP environment. EPI will continue to reinforce these fundamental components to keep everyone working safely.

Training is a foundational component of EPI's corporate culture and is used to ensure safety across all aspects of our organization.

Summary of goals:

- Maintain COR certification (under the "COR 2020" accreditation).
- Continue crew visits by a cross-section of management and senior leadership and deliver feedback.
- Continue all required and discretionary training.
- Continue to conduct community safety awareness campaigns and will continue to reinforce public safety messaging through media and advertising channels.
- Continue to reinforce engineering standards compliance, ensuring that engineering processes are compliant with O. Reg 22/04.
- Continue to share public safety awareness and electrical safety awareness messages and learnings, including conducting contractor electrical safety training, as well as visits to classrooms to educate children about electrical safety

4.2 INSPIRED AND EMPOWERED PEOPLE

EPI's Core Value of Inspired & Empowered People encompasses the OEB's RRFE outcome of Operational Effectiveness. EPI's Core Value of Inspired & Empowered People is defined as:

"Having a workforce of inspired and empowered people who are passionate about their jobs."

- Powered by integrity
- Education and growth opportunities
- Right people in the right places

4.2.1 APPROACH AND ACTIONS

EPI utilizes various approaches and initiatives to attract and retain talent. These include a comprehensive employee recruitment process/policy inclusive of senior leadership approvals, an employee recruitment referral program, a thorough and multi-phase onboarding process, employee engagement programs and communication channels (including employee Town Halls, employee feedback, employee recruitment referral program, employee ideas submission program, social committee, wellness programs, employee donation funds, luncheons, and employee service recognition awards), succession planning, and employee exit interviews.

EPI believes that these initiatives – and the EPI culture, which focuses on treating employees with respect – help to ensure that employees regard EPI as a great place to work.

4.2.2 KEY MEASURES AND PERFORMANCE DISCUSSION

To ensure that employees are "Inspired and Empowered", EPI focuses on its associated measure of Employee Satisfaction. This measure and the associated performance discussion are detailed below.

EMPLOYEE SATISFACTION (CUSTOM MEASURE): MONITOR

Measure: Employee Satisfaction Survey Results	2020	2021	2022	2023	2024
Entegrus Powerlines	n/a	66.4%	n/a	65.9%	n/a

EPI has been conducting the Employee Satisfaction Survey (approximately every other year) since 2010 with the same survey provider. Average scores are calculated for each driver based on a 1-to-7-point rating system, with 1 representing "strongly disagree" and 7 representing "strongly agree". The resultant driver averages are converted by the third-party provider to a range of 0% to 100%. A value of 0% indicates "strong disagreement" with each positively worded question and a value of 100% indicates that everyone in the analysis "strong agreement" with each positively worded question. Values between 0% and 100% are the result of varying degrees of employee agreement – or disagreement – with each driver or item area. A snapshot of overall EPI employee satisfaction is calculated by taking the Grand Average of all drivers of employee satisfaction.

The survey provides important feedback and previous initiatives arising from this feedback have included: the implementation of union staff performance reviews, enhancements to the non-union performance evaluation system, and increased in-person social event opportunities to assist in developing face-to-face relationships (particularly with new employees). This feedback has also led to inter-departmental luncheon initiatives, whereby one department hosts another department.

The above Employee Satisfaction Survey results compare favourably to the third-party provider's database of employer results.

Based on feedback received from the 2023 survey, in 2024, an expanded the first phase of the new employee onboarding (and offboarding process) was implemented. This includes multiple shorter sessions spread across the employee's first week of work. Subsequently, once the new employee is fully immersed, a multi-day comprehensive company-wide session is held for a "class of new employees" over two days across both office locations. This is referred to as "Orientation 2.0" and provides new employees with cross-functional department presentations, process demonstrations, and the opportunity to ask more questions.

Further, employee appreciation days for each department have been introduced, highlighting the role and achievements of departments, including showcasing contributions on digital signage.

As noted in prior Business Plans, EPI holds employee surveys every other year. The next survey is planned for late 2025.

4.2.3 INSPIRED AND EMPOWERED PEOPLE – BUSINESS PLAN GOALS MOVING FORWARD

A skilled and supported workforce is essential to delivering safe, reliable, and responsive service in a rapidly evolving energy sector. A competitive and equitable compensation system is essential to attracting, developing and retaining the skilled employees needed to meet rising customer expectations and operational complexity.

Ontario's electricity sector has long anticipated the challenges of Baby Boomer retirements on the utility workforce, and EPI began experiencing these effects as early as 2016. From 2020 to 2023, retirements accelerated – particularly in technical and operational roles – as the pandemic prompted many long-serving employees to leave the workforce. For EPI, this resulted in a loss of institutional knowledge and a critical need to recruit, transfer knowledge, and build internal capacity. These pressures have been further compounded by a competitive labour market in Southwestern Ontario, making workforce development, succession planning, and a strong internal talent pipeline critical. The following statistics underscore the change in the EPI workforce over the past 10 years:

- As of November 2015, 20% of EPI & STEI employees had less than 5 years of tenure with the organization. In comparison, as of June 2025, 37% of EPI employees have less than 5 years tenure.
- As of November 2015, 47% of EPI & STEI employees were under the age of 45. In comparison, as of June 2025, 67% of EPI employees were under the age of 45.

Beyond succession planning, EPI incremental workforce investments are driven by sector-wide evolution and changing customer expectations and regulatory requirements. Accordingly, EPI transitioned to a more comprehensive workforce strategy. This approach emphasizes both the recruitment of new talent and the upskilling of existing employees to address a broader and more complex range of responsibilities. EPI has concentrated efforts on attracting strong talent with specialized industry competencies, while advancing employee career development through structured training programs and performance management.

The following key drivers have resulted in an increase in EPI Full Time Equivalents (FTEs), from 109 FTEs in 2023 to 125 FTEs in 2026:

- Growth across EPI's service territory – driven by new residential subdivisions and industrial development – has resulted in increased customer connections and a 9% rise in weather-normalized load between 2016 and 2024. At the same time, large portions of the distribution system, much of which was originally constructed in the 1950s, 1960s and 1970s, are reaching end-of-life and require renewal. In response, EPI has implemented a coordinated system renewal and modernization strategy that includes voltage standardization to 27.6 kV and the phase retirement of near-obsolete distribution substations that no longer meet operational or reliability expectations.
- Rising customer expectations and the integration of new technologies, including smart switches, Distributed Energy Resources (DERs), and Non-Wires Alternatives (NWAs). These changes require greater engineering capacity—such as system impact assessments and advanced coordination with industrial customers, the IESO, and the host distributor. In parallel, EPI has transitioned from paper-based processes to digital platforms, including GIS-based mapping and other visualization tools. This increasing reliance on digital systems has also necessitated expanded capabilities in cybersecurity, network protocols, and IT systems monitoring to align with industry standards and risk expectations.
- Ontario's electricity sector is undergoing profound transformation, shaped by technological innovation, evolving legislative and regulatory frameworks, and climate considerations. The IESO projects that demand will grow by 75% by 2050, driven industrial expansion, the electrification of transportation, and ongoing population growth. These changes will place new demands on system capacity and operational resources and responsiveness. While electrification is not yet a primary driver of load growth in EPI's service area, these trends are already reshaping utility planning across the province.

In addition to the recruitment and succession planning function described above, the EPI HR team also leads labour relations matters like collective bargaining and pay equity. The EPI Collective Bargaining Agreements ("CBA"), which covered 2019-2024 at annual increases of 2.0%, expired on December 31, 2024. EPI collective bargaining began in October 2024 and concluded with conciliation in February 2025, followed by successful ratification. The resultant 2025-2027 CBAs include annual increases of 3.5% (2025), 2.25% (2026) and 2.50% (2027). Pay equity maintenance was again achieved in 2024 and will be reviewed next in 2027.

Key 2026 goals related to Inspired & Empowered People include:

- Continued frequent staff engagement and communication, including: (i) Town Hall meetings, (ii) non-union meetings, and (iii) leadership meetings.
- EPI membership/leadership in Grid Smart City and Electricity Distributors Association and consulting with advisors to understand emerging structural changes to the electrical distribution industry and the development of EPI responses.
- Expansion of training opportunities for staff of all levels, including enhancing Grid Smart City / Mohawk College leadership training with a behavioral-based leadership development initiative designed to enhance management coaching effectiveness, employee engagement and performance management. The new training will apply a scientific model of behavior and focuses on targeted leadership approaches.

- The successful recruitment of new resources, including modernized job descriptions where needed and talent acquisition processes to match the evolving complexity of the industry and succession planning.
- Assessing and implementing options for succession planning.
- Continued evolution of the HRIS, including additional reporting refinements and modules as needed.

4.3 CUSTOMER AND COMMUNITY FOCUS

EPI's Core Value of Customer and Community Focus encompasses the OEB's RRFE outcomes of Customer Focus and Public Policy Responsiveness. The Customer and Community Focus Core Value is defined as:

"Exceeding the needs of our customers and the communities we serve, by having a customer and community focus."

- Understanding & exceeding the needs of customers
- Leading customer service
- Community engagement

EPI recognizes that customer engagement is vital to remain relevant and understand the needs and preferences of its customers.

4.3.1 APPROACH AND ACTIONS

EPI continuously engages with customers to understand their needs and preferences and also respond to questions. In recent years, EPI has increasingly added digital channels and resources to provide customers with more choice as to how they engage with EPI. Examples of these channels and resources include:

- The introduction of a live "digital chat" option for customers in 2023.
- An enhanced website which makes information regarding customer bills more accessible. Customers can access frequent billing and payment questions, energy assistance programs and information on how to login to My Account to understand their consumption.
- The website features a public outage map, along with the embedded social media feed, which has made significant improvements to outage communications.
- An online bill calculator was developed and implemented within My Account to help customers understand bill impacts of Tiered vs TOU rates. In 2023, EPI updated this calculator to include the new provincial Ultra Low TOU rate option.
- Providing authorized third-party access to customer data through the standardized Green Button platform.
- All significant planned outages are communicated to customers through IVR (call or text), letter, in-person or live agent calls depending on the situation. Planned outages that affect over 150 customers are also communicated via social media channels. The EPI contact center platform receives the same information and automatically posts a message to our IVR with outage details using text-to-speech.

- Adopted additional communication protocols for critical customers during severe weather and high impact low frequency events.

In addition, EPI continues to provide traditional customer communication. Examples of annual customer touchpoints include:

- In 2024, 54,500 inbound phone calls were answered by EPI Customer Service staff related to customer questions or concerns (e.g. account information and activating new accounts, questions on bills, moves, and outages).
- In 2024, EPI received nearly 22,000 customer service-related emails.
- In 2024, nearly 80,000 outbound interactive voice calls (IVR's) were made by EPI to customers for collection-related activities.
- As of December 31, 2024, more than 40,000 customers had signed up to access "My Account" (EPI's web portal that allows customers to access and analyze their electricity consumption data).
- As of December 31, 2024, EPI had approximately 24,800 customers signed up for e-billing. In addition, 27,500 EPI customers have signed up for pre-authorized payment (PAP).
- 2,000 live chats were handled in 2024.
- EPI has grown its social media presence to include over 8,700 followers on Facebook and 4,600 on X (formerly Twitter). The company also has more than 2,800 followers on LinkedIn and has recently expanded its reach by adding an Instagram page.
- Many customers are contacted each year through customer surveys to discuss operational activities occurring in their area, including EPI maintenance and vegetation management projects.
- Bill inserts and on-bill messages to improve the electricity literacy of customers are provided. For example, bill inserts have included information on: TOU time periods and rate changes, Low-Income assistance programs, digital account options and powerline safety.
- EPI provides annual rate update brochures to customers when changes occur.

Entegrus also engages with customers and the communities throughout the year through other initiatives, including:

- Powerline Safety Public Awareness Campaign, including customer surveys
- Customer transactional surveys (i.e. Bottom-Up) as well as random surveys (i.e. Top-Down) utilizing a third-party survey provider
- Discussing conservation programs with customers
- Engaging with eligible commercial and industrial customers about Class A opt-in
- Organizing annual Holiday meals and support for citizens in need
- Supporting the St. Clair College Powerline Maintainer Program
- Ongoing social media outreach

EPI completed a two-phase customer engagement process in 2024-2025 to inform the development of the 2026 Cost of Service Rate Application, ensuring that customer needs and priorities are reflected in investment planning and service decisions. Additional background on the 2026 Cost of Service Application is provided in the Sustainable Growth section below. Associated customer engagement results are discussed below in the Customer and Community Focus – Business Plan Goals Moving Forward section.

Simultaneously, ongoing trade tensions and evolving tariff policies are creating economic uncertainty, particularly for industrial customers tied to manufacturing and automotive sectors. EPI is monitoring these developments closely and will continue working with affected customers to support ongoing account management and address emerging financial pressures where appropriate.

4.3.2 KEY MEASURES AND PERFORMANCE

To measure Customer and Community Focus and ensure that EPI is on course, EPI focuses on its measure entitled: "Year-Over-Year Customer Satisfaction". EPI also tracks six additional measures related to Customer Service quality, including First Contact Resolution and billing accuracy.

These measures and the associated performance discussion are detailed below.

NEW RESIDENTIAL/SMALL BUSINESS SERVICES CONNECTED ON TIME (SCORECARD MEASURE): TARGET = 90%

Measure: New Residential/ Small Business Services Connected on Time	2020	2021	2022	2023	2024
Entegrus Powerlines	96.91%	97.60%	98.55%	97.48%	97.89%

The Distribution System Code ("DSC") requires electricity distributors to complete a connection for new service under 750 volts within five days from the day on which all applicable service conditions are satisfied. EPI has consistently performed better than the industry standard of 90% in this area and will continue the focus and effort to respond expeditiously.

EPI will continue to maintain processes and resources to ensure that the required 90% standard is met or exceeded.

SCHEDULED APPOINTMENTS MET ON TIME (SCORECARD MEASURE): TARGET = 90%

Measure: Scheduled Appointments Met on Time	2020	2021	2022	2023	2024
Entegrus Powerlines	99.83%	99.71%	100%	99.96%	99.96%

The DSC requires that electricity distributors offer to schedule an appointment within a window of time that is no greater than four hours. The electricity distributor must then arrive for the appointment within the scheduled timeframe 90% of the time. EPI has consistently performed better than the industry standard of 90% in this area.

EPI will continue to maintain processes and resources to ensure that the required 90% standard is met or exceeded.

TELEPHONE CALLS ANSWERED ON TIME (SCORECARD MEASURE): TARGET = 65%

Measure: Telephone Calls Answered on Time	2020	2021	2022	2023	2024
Entegrus Powerlines	79.11%	81.26%	68.42%	83.75%	76.56%

The DSC requires that electricity distributors answer calls within 30 seconds 65% of the time. EPI has historically staffed its Customer Service Call Centre to meet this goal, without significantly exceeding it, to balance the need to prudently deploy resources in all business areas. EPI typically exceeds the industry standard of 65% in this area.

In recent years, EPI enhanced its online customer service offerings to improve the digital customer experience. This includes a redesigned EPI website, an online self-service portal, and social media channels. The improvement to the digital customer experience also helps reduce certain call types in favour of self-service, such as Live Chat, which, in the long term, will assist EPI in enhancing call response time and improving the customer experience. In late 2023, EPI launched a BETA program offering SMS capabilities for planned communications. In 2024, Entegrus enrolled over 1500 customers in the SMS communication program.

Moving forward, EPI will continue to enhance its digital capabilities to offer additional tools the customers are seeking. EPI will simultaneously focus on ensuring staffing and processes are in place to meet the 65% industry standard in this area.

FIRST CONTACT RESOLUTION (SCORECARD MEASURE): MONITOR

Measure: First Contact Resolution	2020	2021	2022	2023	2024
Entegrus Powerlines	74%	85%	81%	75%	75%

Similar to Customer Satisfaction surveys, EPI has been conducting First Contract Resolution ("FCR") surveys (a.k.a Bottom-Up or Transactional surveys) since 2014. However, EPI FCR is determined based on live agent transactional phone surveys conducted by a third-party service provider. EPI provides the provider with a bi-weekly report of all inbound customer telephone calls received. The provider's telephone agents, in turn, contact and survey EPI customers - typically within two weeks of their initial inbound contact. FCR measures (as a percentage) the number of instances where a customer's need is addressed the first time the customer calls. An industry target for this measure has not yet been determined.

EPI believes that FCR can only be measured properly by surveying a random sample of customers who recently contacted EPI. Hence, for EPI, a third-party consultant conducts the survey using a transactional survey approach, and typically contacts EPI customers by telephone within 2 weeks of their initial inbound call to EPI, posing the following question: *"Was the specific question or issue you called about on [*insert date] *resolved during that call*?"

2024 transactional surveys achieved an FCR score of 75%. FCR remains a focus for EPI, the Customer Service Department added a new Customer Service Supervisor dedicated primarily to the staff receiving customer inquiries and call centre activities. This supervisor is focused on staff skills development and the highest quality training, which the surveys provide a key role in driving.

Going forward, EPI plans to continue with transactional (FCR) surveys conducted on an annual basis (throughout the year).

BILLING ACCURACY (SCORECARD MEASURE): TARGET = 98%

Measure: Bill Accuracy	2020	2021	2022	2023	2024
Entegrus Powerlines	99.81%	99.91%	99.91%	99.95%	99.90%

In 2014, the OEB introduced the Billing Accuracy measure. The measure is defined as the number of accurate bills issued expressed as a percentage of total bills issued. It is calculated as: the number of bills accurately issued for the year, divided by the total number of bills issued for the year. The DSC requires electricity distributors to maintain 98% Bill Accuracy, meaning the number of instances (as a percentage) where a customer's bill does not contain errors and does not result in re-issuance.

EPI has met or exceeded the target in the past and will continue to ensure that skilled, trained resources and processes are in place to achieve this target.

CUSTOMER SATISFACTION (SCORECARD MEASURE): MONITOR

Measure: Customer Satisfaction Survey Results	2020	2021	2022	2023	2024
Entegrus Powerlines	93%	92%	93%	94%	92%

EPI has been conducting Customer Satisfaction surveys (a.k.a. Top-Down surveys) since 2014, following OEB survey guidance. Although such surveys are required biennially by the OEB, management assessed the benefits of such feedback and determined that it will typically conduct these surveys annually.

Customer Satisfaction is measured based on live agent phone surveys conducted by a third-party service provider. EPI provides the provider with contact numbers for all of its customers. The provider's agents then contact a random sample of Residential and Small Commercial customers. Customers are asked a variety of survey questions by the provider's agents. In terms of Overall Customer Satisfaction, the exact wording of the survey question posed to customers by the provider is, "Taking everything into consideration, how would you rate your overall EPI experience? Please use a 1 to 5 scale where 1 is not at all satisfied and 5 is very satisfied." The Customer Satisfaction results are reported by the third-party service provider in terms of the percentage of customers reporting that they are satisfied or very satisfied.

Going forward, EPI plans to continue the above-noted annual Customer Satisfaction surveys. The feedback from the process is used to enhance Customer Service processes and agent dialogue.

4.3.3 CUSTOMER AND COMMUNITY FOCUS – BUSINESS PLAN GOALS MOVING FORWARD

As discussed above, EPI is working with a third-party service provider to understand customer needs and preferences to support the 2026 Cost of Service Application. This customer engagement occurred in two distinct phases.

Phase One Customer Engagement

The first phase of customer engagement was completed in July - August 2024 Phase One customer engagement confirmed customer satisfaction, while also identifying specific needs and preferences for EPI to address. These needs and EPI's planned associated actions are detailed below.

Customers prioritize delivering electricity at reasonable distribution rates and ensuring reliable service. When asked about technology priorities, the two highest priorities were "new technologies that would reduce the number and length of outages" and "new technology that can help customers better manage their electricity usage". However, customers also want Entegrus to invest what it takes to replace the system's aging infrastructure to maintain system reliability and proactively make investments in system capacity infrastructure to ensure customers in higher growth areas do not experience a decline in reliability, while also invest in new technologies to improve reliability or provide other benefits.

With regard to specific initiatives in Phase One, the following customer feedback was received:

- Mobile Phone Application: Customers support an app to view their account information, see outages and report outages. This was the top customer service offering priority and EPI conducted additional Customer Engagement in Phase Two for this initiative. Customers are also interested in unplanned outage alerts via text message.
- Tree Trimming & Vegetation Trimming supported by satellite imagery: Customers support this initiative, and EPI conducted additional Customer Engagement in Phase Two for this initiative.
- Demand Response ("DR"): Customers are lukewarm on this initiative, particularly industrial customers and so EPI has not proceeded with a DR initiative at this time.
- Electrification: there is limited customer interest at this time in EV fleets, EV charging, gas to electricity (i.e. heat pumps) or implementing renewable energy sources.

Phase Two Customer Engagement

The second phase of customer engagement was completed in April 2025. Customers were presented with a draft plan and provided broad support, while helping refine specific initiatives. Phase Two engagement received a strong participation from customers across all rate classes, including Residential, Small General Service and C&I / Large Use customers.

The Phase Two results confirm social permission to proceed with the overall draft investment plan, while also validating proposed rate harmonization and the extension of standby rates to the St. Thomas rate zone. Most customers supported either the spending levels proposed in the draft plan or higher levels of investment.

The following customer feedback was received on specific initiatives, and has been incorporated into the 2026 Budget:

- Targeted Reliability (investments to improve service in areas with poorer-than-average reliability): Customers supported this initiative, and Entegrus will proceed with the investment as proposed in the draft plan. The importance of addressing localized reliability concerns was acknowledged across all customer groups.
- Community Growth (transformer investments to support increased demand for electricity): There was

strong customer support to proactively address capacity constraints. As a result, Entegrus has increased the draft capital plan to accelerate at-risk transformer replacements and ensure growing communities are supported.

- Tree & Vegetation Trimming (use of satellite imagery and emerging monitoring technologies): This initiative was originally introduced in Phase One, and after presenting additional details and cost impacts in Phase Two, customers expressed clear support. Entegrus will include this initiative in the 2026–2030 DSP.
- Mobile Phone Application: Originally identified as a service priority in Phase One, this initiative again received support when further information was provided. Entegrus will proceed with plans to develop and launch the app, enabling customers to view their account, see outage maps, and report outages directly.
- Rate Harmonization: Customers across both Legacy Entegrus and St. Thomas rate zones expressed general support for harmonizing distribution rates or acknowledged that the change is necessary. Entegrus will proceed with rate harmonization in the 2026 Cost of Service application.
- Extension of Standby Rates to St. Thomas: Most customers support or accept this change. Entegrus will proceed with the proposal to apply standby rates consistently across all service areas in the 2026 Cost of Service Application.

Phase Two engagement confirmed that customers support EPI investing to maintain and modernize the system, particularly in reliability, growth, and customer service. The customer preferences and input received has helped shape EPI's investment plans.

Key 2025 goals related to Customer and Community include:

CONSUMPTION MANAGEMENT TOOLS AND AWARENESS

- Additional marketing to drive more customer awareness of the existing web-based tools that are available to customers.
- A new bill design optimizing clarity and ease of use for customers.
- Enhancements to EPI's digital communications tools
- Entegrus.com redesign to enhance user experience and engagement, leading to increased customer satisfaction and higher adoption of digital self-service tools.
- Based on Phase 1 customer engagement conducted by the third-party service provider, an overhaul of EPI's "My Account" on-line consumption management tool is planned, which will include a mobile application component where customers can choose tailored communication means and view and report outages electronically.
- Further investigation of online chat capabilities for customer service.

IMPROVING FIRST CALL RESOLUTION

- Continue to work with third-party consultants and the associated Customer Service Representative online portal that compares ongoing individual survey results against the aggregate departmental results.
- Utilize the online portal to identify which type of customer contact issues are being handled well and where there are opportunities for additional training.

- Harmonization of Customer Interaction
- Promote energy literacy with the customers.
- Support customers with IESO centralized conservation programs. Implement Innovative solutions for providing customers with exceptional service using the My Account tool.

HARMONIZATION OF CUSTOMER INTERACTION

- Promote energy literacy with the customers.
- Enrol in the IESO's 2025 eDSM framework to support customers with conservation programs literacy and uptake.
- Implement Innovative solutions for providing customers with exceptional service using the My Account tool.

4.4 OPERATIONAL EXCELLENCE

EPI's Core Value of Operational Excellence encompasses the OEB's RRFE outcome Operational Effectiveness. The Operational Excellence Core Value is defined as:

"Achieving operational excellence by always striving for continuous improvement."

- Efficient
- Effective
- Continuous improvement
- Innovative solutions
- Intelligent investment

Operational Excellence means EPI employees are encouraged to improve on past successes within a continuous improvement framework. This core value requires the examination of fundamental processes that create value for EPI's customers and stakeholders. Identification of these processes and systematic review of each with continuous improvement tools such as re-engineering, innovation, benchmarking, and value stream mapping will determine how to improve each process. Examples of core processes are the Distribution System Plan ("DSP"), system modernization and implementation of public policy initiatives. These will be discussed below.

4.4.1 APPROACH AND ACTIONS

THE DISTRIBUTION SYSTEM PLAN (DSP)

EPI is currently operating a formal asset management program originally established in 2016 and updated as part of the 2021-2025 DSP. The 2026-2030 DSP is near completion and is being updated for the most recent customer engagement feedback.

EPI asset management practices focus on executing the plans laid out in the DSP while continuing to advance the effectiveness of the asset management practices. As outlined in the DSP, to achieve maximum value per dollar spent, EPI's asset management practices involve running select assets to failure. To ensure that reliability is maintained within the targets, asset management develops capabilities through enhancements to the collection and analysis of additional available asset data. The additional data will enhance scoring of failure impacts, allowing engineers to better target investments. Part of this development involves improvements to EPI's GIS system. The asset management efforts were supported by a GIS upgrade which was completed in 2023 and 2024. This upgrade provided significant modernization to the GIS system, by improving accessibility, data integrity and system visualization. It is anticipated that this capability will be developed enough to influence the Asset Management Framework supporting the 2026-2030 DSP.

EPI conversion plans are focused on the decommissioning of another five (5) of EPI's 27.6/4 kV substations over the 2026-2030 DSP period. To meet this objective, EPI's asset renewal programs are highly focused on executing a targeted conversion plan. Conversion programs are currently focused on the cities of Chatham and St. Thomas and are composed to allow the efficient use of engineering and field resources over the duration of the conversion program. Over the 2026-2030 DSP period, EPI's conversion plans include focus on the communities of Strathroy and Blenheim.

SUPPLY ADEQUACY

Load growth in our communities is driving the need to establish additional supply points in several of our communities. This need is driven by a combination of customer growth and accelerated by the impacts of electrification.

Between 2025-2030, new supply points (and the associated line buildout) are required for:

- St. Thomas (new Edgeware TS breaker and feeders in 2025 for existing and ongoing growth)
- Mount Brydges (phased conversion and 2027 supply point)

Longer term, supply upgrades will later be required in the following communities:

- Chatham
- Strathroy
- Tilbury
- Dutton
- Parkhill
- Thamesville

ENTERPRISE ASSET MANAGEMENT GIS AND MCARE

As noted above, EPI continues to operate a formal asset management program established as part of the 2021-2025 DSP. This program undergoes annual evaluation and improvement to extend and update the Asset Condition Report and associated asset planning based on improved field data and asset management science.

Enterprise asset management refines and updates the capital plan to cost-effectively maintain EPI's investment in its distribution assets while ensuring EPI can meet customer growth needs, improving on the ability to respond to and control reliability and power quality concerns. It is developed in response to many factors including:

- Customer growth forecasts gathered from Economic Development and conversations with developers

and potential customers.
- Data available from the field asset information collection activities.
- Field measurement from Smart Meters, SCADA and data generated as smart grid devices are added to the system.
- System outage information.
- System switching and asset operation records.
- Progress on the existing capital plan.
- Connectivity information in the GIS.

Work programs are being developed based on assets at the highest risk, customer-driven initiatives, special projects that provide high value to EPI's customers, overall system performance and projects that will provide a long-term benefit to EPI's shareholders including projects that prepare the grid for electrification.

Asset management staff continue to enhance the capabilities and use of the GIS system each year to improve asset management, operations, and safety. Each year conversion plans are developed and updated, while additional analysis is completed to ensure that EPI meets the objectives outlined in the DSP.

The GIS system stores a record of all assets and the relationships between them. In 2024, EPI completed a major version upgrade on its GIS system. This upgrade included migration to a new data model, as well as a full replacement of all client and server software associated with the system. This new software makes EPI's GIS data more accessible on mobile devices and the web, while improving data integrity and streamlining licensing. As the complexity of the system grows from a myriad of novel pressures and technologies, EPI will continue to invest in and leverage appropriate tools to enable it to continue to deliver innovative, cost-effective solutions for its customers and shareholders.

SYSTEM MODERNIZATION

EPI explores innovative solutions to solve customer, and distributor challenges and therefore continues to invest in Smart Grid technologies. Consistent with the strategy outlined in the DSP, EPI continues to invest in distribution automation projects and modernization of communication systems supporting these projects. Building on previously successful projects in Wallaceburg, Tilbury, Ridgetown, Thamesville, Erieau and Blenheim; the deployment of automated switches in Chatham started in 2022 and will be ongoing through the 2026-2030 DSP period. This will assist with improved reliability in the community. St. Thomas is also targeted for Smart Grid technology in the 2026-2030 DSP period.

EPI continuously studies how new technology will impact the distribution system. Changes to enable and require net zero homes and transportation electrification are already being worked into the Ontario building code. EPI is currently working with an innovative and forward-looking home developer on a metering pilot to support net-zero housing and gain knowledge and validate study results.

Based on a review consisting of internal analysis, participation in industry group-sponsored studies, and literature surveys, EPI has recently adopted new design standards for its residential customers. This new standard is better aligned with EPI's customer's current needs and enables cost-effective upgrades in the future as forecasted uptake in electric vehicles, home heating electrification and new distributed energy penetration rates (including service scale storage) emerge.

ENERGY STORAGE

Energy storage solutions are evolving very quickly. EPI recognizes the role that this technology will play in the future and is evaluating the technology's capabilities, effectiveness, maintenance requirements, customer benefits, and rate implications of these projects.

While Energy Storage solutions add to the distributed energy portfolio within a community, limitations on the amount of storage are governed by the electrical properties of the system and its ability to withstand the additional fault currents that are associated with these storage solutions.

Consistent with OEB requirements, EPI considers non-wires alternatives (such as DER's and Energy Storage) before committing to any significant capital project. EPI is not currently forecasting widespread adoption of storage technologies within its service territory during this 2026-2030 time horizon.

RELIABILITY IMPROVEMENTS

Significant efforts are being made to proactively identify rotted or end-of-life poles through field mapping work. A systematic pole testing program was initiated in 2015 and continues to gather data on the health of the poles. Pole testing is also performed both proactively and on-demand as the need is identified. An expanded pole inspection procedure was piloted in 2022 and adopted for 2023 and future work. This expansion provides richer data to help drive improved asset management practices. Preventive maintenance programs such as tree trimming, and identification and replacement of porcelain insulators and rotted poles will continue.

Customer engagement supported the use of satellite imaging to support tree trimming and vegetation management. This technology involves the use of satellite imagery to form a 3D model of the distribution system and the trees in the communities to indicate precisely where tree trimming is needed, as well as forecasting when trimming will be needed with a great degree of granularity (down to the street/block). This will allow EPI to optimize the efforts of its tree-trimming contractors. A year-over-year program enables enhanced validation/quality auditing of the previous year's work.

EPI's deployment of distribution automation equipment is currently focused on improving system segmentation, which reduces the potential reliability impacts of a single asset failure. This is expected to remain the focus in the medium term.

IMPLEMENTATION OF PUBLIC POLICY INITIATIVES

EPI is committed to embracing and supporting public policy initiatives. Historic and recent examples of EPI implementation of public policy initiatives include:

- **Smart Meters:** EPI was an approved early adopter of smart meters and originally installed most of its Residential smart meter fleet between 2006-2007. EPI takes immense pride in its pioneering role in this initiative and demonstrated leadership in the implementation process both in its own service areas and by sharing its learnings and experience with the industry. During the 2026 – 2030 period, approximately 39,700 meters seal will expire. However, many of these meters are operating beyond their expected lifespans. Where possible EPI utilizes Measurement Canada Sampling program to ensure measurement accuracy and minimize replacement cost. Approximately 5,000 meters tested poorly during their 2024, 2nd seal period sampling. As per Measurement Canada sampling regulation, the lots were granted the maximum 2 Year extension without the ability to be sampled again and must be replaced no later than 2026.

- **Time-of-Use Billing:** EPI piloted Residential TOU billing in 2007 and completed Small General Service TOU billing on deadline by June 2011, without seeking an extension from the OEB throughout the process. Ultra-low billing and the full complement of Green Button were introduced in 2023.
- **Conservation and Demand Management ("CDM"):** EPI has offered the OPA/IESO Save on Energy CDM programs since their inauguration in 2006, including launching these programs at legacy utilities as they were acquired. EPI plans to enrol in the IESO's 2025 eDSM framework to support customers with conservation programs literacy and uptake.
- **Renewable Generation:** EPI continues to focus on supporting renewable generation, including ensuring that connection requirements are met. As of June 2025, the OEB has implemented enhanced DER connection requirements for electricity distributors, introducing more standardized procedures, detailed information-sharing obligations, and Connection Impact Assessment (CIA) processes that increase consistency and drive greater coordination between stakeholders, including host distributors. EPI will meet these expanded obligations and ensure that customers have timely access to DER connections.
- **Locates:** In May 2024, new Ontario regulations became effective which established time limits for locates, along with giving Ontario One Call the ability to levy administrative penalties against underground infrastructure owners for non-compliance. EPI has focused on its commitment on completing all locates within the mandatory time periods set out by Ontario One-Call. Accordingly, EPI hired a Supervisor of Locates as well as adding a Locator in St. Thomas. EPI continues to meet and exceed industry / Ontario One Call requirements.

THE FUTURE OF LDC DISTRIBUTION INFRASTRUCTURE

As previously noted, the IESO's 2024 Annual Planning Outlook forecasts a sharp increase in Ontario's electricity demand, from 144 TWh in 2023 to approximately 263 TWh by 2050 (a 75% increase), driven by industrial expansion, the electrification of transportation, and ongoing population growth. This will put significant demand on electrical distribution systems.

While it can be expected that new technologies and distributed energy resources will play an important part in the future of the LDCs, it is important that EPI investigate, analyze, and plan for these changes to ensure that we provide value to the customers and safeguard the distribution system.

Previous concerns about grid abandonment (i.e. customers islanding from the grid) have been replaced with more recent concerns around meeting capacity needs for our customers as decarbonization initiatives drive the electrification of home heating and transportation. Historical distribution system design practices will need to be adapted to accommodate this level of loading. It is expected that selected neighborhoods will begin to require additional investment to address equipment overloading starting in the next few years. In Customer Engagement, customers supported additional investment in 2026-2030 to proactively address capacity constraints. As a result, Entegrus has increased the capital plan by $500,000 per year for 2026-2030 to accelerate at-risk transformer replacements and ensure growing communities are supported.

The challenges EPI will be facing in terms of distribution capacity are not unique. They will be – and are being faced – by the entire industry globally. To this end, EPI has participated in, and continues to seek participation in, OEB, IESO and EDA initiatives to help define these needs and develop best practices to address them.

Distributed Generation is expected to continue to grow at a steady rate within our system. The cost of solar continues to fall, while the cost of centralized grid-level generation continues to rise. The cost of local generation may reach unsubsidized parity within this plan window. Once parity is achieved, DER adoption is expected to occur at accelerated rates.

As distributed generation, transportation electrification, and heating electrification grow our distribution system will become more dynamic, with complex, time-varying constraints beginning to occur at the local level (i.e. 11 AM a neighborhood may become constrained on energy export from the local generation, but at 6:00 PM, the neighborhood may be constrained on energy import from the density of car chargers).

This represents a radical transformation in the way the consumers relate to electrical energy and a correspondingly radical change in the way the distribution system is used. It will place new demands on our assets, including significant new demand for our smart metering system.

While new capabilities (in both labor and technology) will be required to manage the increased system complexity, EPI has been working to lay the foundation for this analysis technology through its asset management and GIS practices to ensure that it is well-positioned to adopt these new tools and processes as they become required.

Given the magnitude of the changes anticipated, a pure poles-and-wires solution is unexpected. New regulatory frameworks and settlement options will be required to provide the economic levers to allow these levels of loading and generation to co-exist within the distribution system. In January 2024, EPI Engineering, System Planning, and Regulatory staff took part in a multi-day electrification/energy transition training session, which also included associated regulation evolution concepts. The training was developed by EPI with a consultant and facilitated by experienced engineers and regulatory specialists. The next session will be held in 2026.

EPI believes the prudent approach is to continue to ensure that EPI is engaged in interdepartmental and interagency communications about new technology and the challenges that may arise from such products. Continued participation in user groups and distribution conferences will provide early insight into such trends. For the short term, management feels there is a minor risk to the current delivery model, but it will be important that EPI continues to strengthen the relationship with our customers and provide value. Given the uncertainty around the timing and intensity of these new loads, maintaining communication with other utilities, monitoring activities in other jurisdictions, and keeping current on best practices will be key going forward.

INFORMATION TECHNOLOGY AND CYBER SECURITY

EPI is advancing its digital transformation through the progressive adoption of business process automation, digitalization, analytics, IoT, and AI. These technologies are key to improving operational efficiency, enhancing customer service, and enabling smarter decision-making. As EPI's systems become more interconnected and data-driven, maintaining a strong cybersecurity posture across both IT and OT environments is critical.

EPI is committed to a cybersecurity program that meets or exceeds OEB expectations. Our approach is progressive and risk-based, ensuring that improvements are practical, measurable, and aligned with operational priorities.

Key focus areas for 2026 and Beyond:

- **Third-Party Risk Management**: Third-party risk management is a top priority. EPI will enhance vendor risk assessments and embed clear security expectations into procurement processes. In addition to upfront due diligence, EPI will implement continuous monitoring of critical vendors to ensure ongoing alignment with cybersecurity requirements and emerging risk indicators.
- **Independent Cybersecurity Assessments**: As mandated by the OEB, EPI will complete an independent cybersecurity assessment in 2026 and every two years thereafter to evaluate control maturity and identify areas for improvement under the OEB Cyber Security Framework.
- **Identity and Access Security**: EPI will continue advancing its Zero Trust posture by enforcing least privilege access, securing hybrid environments, and maintaining comprehensive identity and access visibility.
- **OT Visibility and System Hardening**: Monitoring and detection capabilities will be extended to OT environments, including devices in the field. These efforts will be supported by continued improvements in system hardening through better network segmentation, stricter access control, and specialized tools for industrial protocols.
- **Threat Exposure Monitoring**: EPI will maintain continuous monitoring of its external attack surface to proactively identify and mitigate vulnerabilities.
- **Resilience Testing and User Awareness**: EPI will conduct regular tabletop exercises and simulated incidents to test response and recovery procedures as part of its broader focus on organizational readiness. These activities support compliance with the Ontario Cyber Security Framework and strengthen EPI's operational resilience. The user awareness program includes monthly phishing simulations, which have improved employee vigilance and lowered click rates. Staff who fail simulations are automatically assigned follow-up training. Briefings based on current threat intelligence are provided to privileged users, leadership, and IT staff to reinforce secure practices. Metrics including simulation results and training completion will be tracked and reported quarterly to senior leadership to ensure accountability and guide improvements. EPI will also participate in GridEx, the biennial North American incident response exercise led by the North American Electric Reliability Corporation. This event enables utilities to test coordination and communication during simulated cyber events and supports validation of EPI's Business Continuity Plan.
- **Responsible AI Adoption and Data Protection**: As AI tools become more integrated into business workflows, they introduce new risks, particularly around unintentional data exposure to public AI platforms. To address this, Entegrus will strengthen IT policies and implement controls that detect and prevent the sharing of sensitive or regulated data with unauthorized AI services. These safeguards will support responsible AI use while protecting customer, employee, and operational information.
- **Sector Collaboration**: EPI remains actively engaged with the OEB CSAC, GridSmartCity ("GSC"), and the Utilities Standards Forum ("USF") to share knowledge, align with best practices, and contribute to the advancement of cybersecurity across the sector.

This progressive and coordinated approach ensures EPI continues to grow its cybersecurity maturity alongside its digital transformation, supporting secure, efficient, and reliable utility operations.

4.4.2 KEY MEASURES AND PERFORMANCE DISCUSSION

To measure Operational Excellence and ensure that EPI is on course, management focuses on three key measures related to reliability. EPI also tracks additional measures related to reliability, system performance, cost containment, planning quality and public policy implementation.

These measures and the associated performance discussion are detailed below.

AVERAGE NUMBER OF HOURS THAT POWER TO A CUSTOMER IS INTERRUPTED (SCORECARD MEASURE): TARGET = 1.42 (5 YEAR TARGET) AND 1.61 (4 YEAR TARGET)

Measure: Average Number of Hours that Power to a Customer is Interrupted	2020	2021	2022	2023	2024
Entegrus Powerlines	1.47	1.09	1.76	1.31	1.26

EPI utilizes an automated system based on smart meter data and other operational data to track outages and SAIDI data. This system is complemented by the Control Room and System Planning review of the output, inclusive of cause code input. EPI's 2021-2025 DSP established the new 5-year SAIDI target for EPI as 1.42 hours and a 4-year target (which normalized the low 2016 results and its anomalous weather conditions from the target average) of 1.61. These targets will be reset as part of the 2026 Cost of Service.

Although weather has played a role in the above-noted results and whether the target for each year was achieved or not achieved, EPI recognizes a strong need for system renewal to mitigate customer interruptions. Starting in 2020, Entegrus has intensified its efforts on system renewal, including remediation of at-risk poles, which will contribute to a reduction in outages that would otherwise occur. EPI also continues to focus on the installation of smart grid equipment in order to reduce outage times, improve outage tracking and provide additional accuracy to the reporting systems.

AVERAGE NUMBER OF TIMES THAT POWER TO A CUSTOMER IS INTERRUPTED (SCORECARD MEASURE): TARGET = 1.01 (5 YEAR TARGET) AND 1.08 (4 YEAR TARGET)

Measure: Average Number of Times that Power to a Customer is Interrupted	2020	2021	2022	2023	2024
Entegrus Powerlines	1.18	1.02	1.18	0.93	1.48

EPI uses the same automated system to track SAIFI data. EPI's 2021-2025 DSP established the new SAIFI target for EPI as 1.01 and a 4-year target (which normalized the low 2016 results and its anomalous weather conditions from the target average) of 1.08. These targets will reset as part of the 2026 Cost of Service.

Although weather has played a role in the above-noted results and whether the target for each year was achieved or not achieved, EPI recognizes a strong need for system renewal to mitigate customer interruptions. Starting in 2020, Entegrus has intensified its efforts on system renewal, including remediation of at-risk poles, which will contribute to a reduction in outages that would otherwise occur. EPI also continues to focus on the installation of smart grid equipment in order to reduce outage times, improve outage tracking and provide additional accuracy to the reporting systems.

CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI) (DSP MEASURE): MONITOR

Measure: Average Time for Service to be Restored for Each Customer after an Outage has Occurred	2020	2021	2022	2023	2024
Entegrus Powerlines	1.25	1.07	1.49	1.41	0.85

CAIDI is formulated from the combination of SAIDI and SAIFI. Since Entegrus already factors both of these metrics into its decision-making process this metric is only monitored for material deviations. An unexplained material deviation would be investigated further to ensure no blind spots are present in Entegrus' capital planning process.

MOMENTARY AVERAGE INTERRUPTION FREQUENCY INDEX (MAIFI) (DSP MEASURE): MONITOR

Measure: Average Number of Momentary Interruptions Experienced by a Customer	2020	2021	2022	2023	2024
Entegrus Powerlines	2.98	2.69	2.02	2.77	2.99

In a modern overhead distribution system, protective equipment and smart switches are used to minimize outages experienced by our customers. They work by converting what would have been a permanent outage requiring manual intervention into a temporary one resolved swiftly (within 60 seconds) by the equipment itself. As such a moderate level of momentary interruptions in the system is an indication that investments into advanced protection systems and automation equipment are serving their desired roll. Excessive momentary outages can signal a need for maintenance or renewal on a segment of line.

EPI monitors this metric. The EPI Control Room monitors momentary outage events and kicks off additional line inspection activities if indicated.

DISTRIBUTION SYSTEM PLAN IMPLEMENTATION PROGRESS (SCORECARD MEASURE): MONITOR

Measure: Distribution System Plan Implementation Progress	2020	2021	2022	2023	2024
Entegrus Powerlines	112.4%	20.2%	40.6%	61.9%	88.4%

In September 2021, EPI filed its 2021-2025 DSP with the OEB in accordance with the requirements of the OEB's 2017 EPI / STEI merger Decision.

The next DSP will be filed with the 2026 Cost of Service and will cover the period 2026-2030.

EPI reports this metric based on the percentage of actual life-to-date capital expenditures divided by the aggregate total 2021-2025 DSP capital plan. Going forward, EPI will continue to track DSP implementation progress against the plan and then will track against the 2026-2030 DSP when implemented.

LINE LOSSES (DSP MEASURE): MONITOR

Measure: Line Loss	2020	2021	2022	2023	2024
Entegrus Powerlines	4.01%	3.81%	3.71%	3.84%	3.82%

Line loss is calculated as the percentage of electrical energy lost, due to heat and transformer losses, in the transmission of electrical energy from the supply points with HONI or the IESO grid to EPI's customers. By focusing on reducing line loss, EPI can ensure more efficient distribution of electricity and reduce customer bill costs.

EPI does not have a target for this metric but strives to see a year-over-year decrease. Moving forward, EPI's plan to achieve this goal includes both capital investments in our system such as the conversion of lower voltage feeders to 27.6 kV and decommissioning distribution stations, and ongoing maintenance such as the small conductor upgrade program.

WORST PERFORMING FEEDER (DSP MEASURE): MONITOR

Worst Performing Feeder ("WPF") analysis is intended to identify those portions of the distribution system (feeders) that are experiencing sustained interruptions. EPI catalogs the reliability (i.e. SAIDI/SAIFI/CAIDI) performance of each of its 27.6kV feeders on a 3-year rolling average. This involves tracking outage information and associating it with the feeder that suffered the associated outage.

EPI uses this analysis to maintain and improve the system-wide SAIDI/SAIFI/CAIDI and measures success against achieving those specific targets. Feeders with the worst reliability performance are then identified and studied to identify the root cause(s) of the poor reliability. Once the analysis is complete, targeted remediations can be scheduled. This may involve the development of asset renewal projects, smart grid projects, additional vegetation management, or any number of other solutions depending on the determined cause.

The table below is an example, depicting the worst performing feeders in 2024 based on SAIDI and SAIFI metrics.

SAIDI Rank (Target 1.61)					SAIFI Rank (Target 1.08)			
2024: SAIDI					2024: SAIFI			
Feeder	SAIDI	Ranking	Change in Rank		Feeder	SAIFI	Ranking	Change in Rank2
1M2	4.7736	1	↑+9		1M2	5.1000	1	↑+25
27M5	4.1266	2	↑+21		1M6	3.3028	2	↑+1
1M6	3.2593	3	↑+8		27M5	3.2143	3	↑+18
5M17	2.5818	4	↑+21		5M4	3.1435	4	↑+9
24M4	2.5698	5	↑+8		5M4	3.1435	5	↑+8
DTF1	2.0280	6	↑+25		5M21	3.0792	6	↔
5M4	1.5602	7	↑+11		24M4	2.1082	7	↑+15
5M4	1.5602	8	↑+10		5M17	1.9875	8	↑+19
5M3	1.3848	9	↑+5		5M22	1.5838	9	↑+2
29M2	1.2518	10	↓-8		5M7	1.3743	10	↓-9
5M15	1.1701	11	↑+8		1M5	1.2443	11	↓-6
5M15	1.1701	12	↑+7		5M3	1.1845	12	↔
5M22	1.0177	13	↑+3		DTF1	1.1525	13	↑+20
5M16	1.0115	14	↓-13		27M1	1.1133	14	↑+15
5M7	0.9973	15	↓-10		29M2	1.0413	15	↓-13
27M10	0.9629	16	↑+5		5M15	0.9177	16	↑+8
MBF3	0.8558	17	↔		5M15	0.9177	171	↓-147
27M1	0.8281	18	↑+9		5M8	0.8658	18	↓-8
BOF1	0.7757	19	↓-10		5M16	0.6163	19	↓-15
5M21	0.6116	20	↓-12		BOF1	0.5791	20	↓-11
5M8	0.5303	21	↑+1		27M10	0.5393	21	↓-6
1M5	0.3759	22	↓-16		MBF3	0.3868	22	↓-3
29M4	0.2610	23	↓-11		29M4	0.2331	23	↓-9
393M22	0.1840	24	↑+9		NBF2	0.1991	24	↑+8
TDSF1	0.1511	25	↓-18		27M6	0.1913	25	↑+3
ERF2	0.1113	26	↓-23		393M22	0.1393	26	↑+4
52M24	0.0506	27	↑+3		ERF2	0.0702	27	↓-11
27M6	0.0467	28	↓-8		TDSF2	0.0467	28	↓-20
TDSF2	0.0389	29	↓-25		1M1	0.0410	29	↑+2
1M1	0.0253	30	↓-1		TDSF1	0.0332	30	↓-23
MEF3	0.0139	31	↓-16		52M24	0.0139	31	↓-11
NBF2	0.0045	32	↓-4		MEF3	0.0092	32	↓-9

Going forward, EPI will continue to utilize Worst Performing Feeder data to prioritize capital programs.

DEFECTIVE EQUIPMENT RELIABILITY (DSP MEASURE): MONITOR

Measure: Average Number of Hours that Power to a Customer is Interrupted due to Defective Equipment	2020	2021	2022	2023	2024
Entegrus Powerlines	0.97	0.32	0.41	0.61	0.47

Measure: Average Number of Times that Power to a Customer is Interrupted due to Defective Equipment	2020	2021	2022	2023	2024
Entegrus Powerlines	0.54	0.24	0.45	0.44	0.44

The purpose of this metric is to visualize the direct effect of System Renewal investments on customer experience. From 2020 to 2021, the impact of our efforts was clear as we noticed a significant decline in interruption duration and frequency. However, the numerous weather storms throughout the region in 2022 and 2023 emphasized the importance of not only renewing outdated equipment but also building to contemporary standards that enhance the system's ability to withstand these severe weather conditions.

EFFICIENCY ASSESSMENT (SCORECARD MEASURE): TARGET = COHORT 2 OR BETTER

Measure: Efficiency Assessment	2020	2021	2022	2023	2024
Entegrus Powerlines	2	1	1	1	1

EPI began tracking the OEB's efficiency measures at inception in approximately 2008. The OEB Total Cost Benchmarking econometric ranking methodology, entitled "Efficiency Measure" (along with the Total Cost per Customer Measure and the Total Cost per kM of Line Measure) is based on a statistical total cost benchmarking study. The study is designed to make inferences on the cost efficiency of individual distributors based on econometric modeling conducted by an OEB consultant to produce a single efficiency ranking. Electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs over the past three years. From 2012 until 2020, EPI was ranked second in five efficiency cohorts.

Since 2021, EPI has been ranked in the first efficiency cohort, which is considered the "most efficient" tranche. As noted above, EPI has maintained this standing despite a broad-based rise in inflation across the Canadian economy, during which the cost of certain key material inputs increased beyond the level of inflation. As described below, going forward, EPI's goal is for its actual total costs to be 10% or more below the total costs predicted by the OEB's econometric model. This would translate to EPI being in the 2nd efficiency cohort or better.

ACTUAL VS PREDICTED ECONOMETRIC TOTAL COSTS (CUSTOM MEASURE): 10% OR MORE BELOW TOTAL COSTS PREDICTED BY THE OEB MODEL

Measure: Actual vs. Predicted Econometric Total Costs	2020	2021	2022	2023	2024
Entegrus Powerlines	(25.4%)	(28.7%)	(26.9%)	(27.8%)	TBD

As described above, the OEB conducts annual econometric total cost assessments of Ontario electrical distributors. Using this information, EPI tracks Actual vs. Predicted Econometric Total Costs.

EPI's 2023 actual costs were 27.8% lower than the OEB Benchmarking model's predicted costs, the 2024 results will be available in Q3, 2025.

Going forward, EPI's goal is for its actual total costs to continue to be 10% or more below the total costs predicted by the OEB's econometric model. This will ensure that EPI remains able to meet or exceed service quality metrics while also evolving with the industry and having sufficient qualified resources to meet modern utility requirements and deploy operational technologies.

TOTAL COST PER CUSTOMER (SCORECARD MEASURE): MONITOR

Measure: Total Cost per Customer	2020	2021	2022	2023	2024
Entegrus Powerlines – with econometric adjustment	$553	$558	$627	$713	TBD

As discussed above under the Efficiency Measure, Total Cost per Customer is based on a statistical total cost benchmarking study commissioned by the OEB. For this measure, each distributor's Total Costs (including O&M and Admin costs) are divided by the number of customers applicable to each distributor (including certain adjustments to make the costs more comparable between distributors).

In terms of cost containment, EPI's overarching goal (as discussed above under the Efficiency Measure) is for its actual total costs to be 10% or more below the total costs predicted by the OEB's econometric model. This goal, in turn, should drive a relatively lower Total Cost per Customer versus the industry. The 2024 results will be available in Q3, 2025.

TOTAL COST PER KM OF LINE (SCORECARD MEASURE): MONITOR

Measure: Total Cost per KM of Line	2020	2021	2022	2023	2024
Entegrus Powerlines – with econometric adjustment	$11,008	$10,670	$11,977	$13,731	TBD

Consistent with the above under the previous Measures, the Total Cost per km of Line is based on an econometric total cost benchmarking study commissioned by the OEB. For this measure, each distributor's Total Costs (including O&M and Admin costs) are divided by the km of line applicable to each distributor (including certain adjustments to make the costs more comparable between distributors).

In terms of cost containment, EPI's overarching goal (as discussed above under the Efficiency Measure) is for its actual total costs to be 10% or more below the total costs predicted by the OEB's econometric model. This goal, in turn, should drive a relatively lower Total Cost per km of Line versus the industry. The 2024 results will be available in Q3, 2025.

ADDITIONAL COST METRICS (CUSTOM MEASURE): MONITOR

Starting with the 2021-2025 DSP, EPI began to monitor the following metrics (none of which include econometric adjustments): Total Cost per MW, Total Capex per Customer, Total Capex per KM of Line, Total O&M Per Customer, Total O&M Per KM of Line, Total Cost Per Customer, Total Cost Per KM of Line. Entegrus uses the OEB's Open Data to gather the information required for the monitoring calculations. The Capex amount is net of contributed capital, and the OM&A costs include operating, maintenance and administrative costs. Where data was available prior to 2021, EPI has provided prior period data in the results below.

Year	*Cost Metric*	*CAPEX Metrics*		*O&M Metrics*		*Total Cost Metrics*	
	Total Cost Per MW	Capex Per Customer	Capex Per KM of Line	O&M Per Customer	O&M Per KM of Line	Cost Per Customer	Cost Per KM of Line
2019	$ 76,100	$ 170	$ 3,297	$ 73	$ 1,408	$ 243	$ 4,705
2020	$ 91,071	$ 217	$ 4,330	$ 65	$ 1,302	$ 283	$ 5,632
2021	$ 96,514	$ 231	$ 4,428	$ 75	$ 1,439	$ 307	$ 5,867
2022	$ 98,807	$ 227	$ 4,329	$ 85	$ 1,616	$ 311	$ 5,945
2023	$ 103,133	$ 234	$ 4,511	$ 88	$ 1,705	$ 323	$ 6,216

EPI is facing inflationary cost pressures, particularly in the last few years. However, EPI continues to exceed econometric expectations based on its Cohort 1 Efficiency Assessment ranking and continued improvement in Actual vs. Predicted Econometric Total Costs. This infers that the industry has been experiencing similar impacts, particularly post-pandemic. The 2024 results will be available in Q3, 2025.

POLES, TOWERS AND FIXTURES GROSS CAPITAL UNIT COST (CUSTOM MEASURE): MONITOR

Measure: POLES, TOWERS AND FIXTURES GROSS CAPITAL UNIT COST	2021	2022	2023	2024
Entegrus Powerlines	$7,763	$8,511	$8,364	TBD

EPI tracks the average cost of Poles and tower structures and updates these values annually as part of its budget development process. This metric was introduced as part of the 2021 DSP, so data is tracked from 2021 forward. The installed cost for a single circuit, 27.6kV pole (our most common installation type) at current standards is used as a representative value for this metric.

It is evident that EPI has been facing inflationary cost pressures over the past few years. However, EPI continues to exceed econometric expectations based on its Cohort 1 Efficiency Assessment ranking and continued improvement in Actual vs. Predicted Econometric Total Costs. This infers that the industry has been experiencing similar impacts, particularly post-pandemic. The 2024 results will be available in Q3, 2025.

TRANSFORMERS GROSS CAPITAL AND UNIT COST (CUSTOM MEASURE): MONITOR

Measure: TRANSFORMERS (EXCLUDING STATION TRANSFORMERS) GROSS CAPITAL AND UNIT COST	2021	2022	2023	2024
Entegrus Powerlines	$10,269	$7,422	$12,119	TBD

Entegrus tracks the average cost of transformers and updates these values annually as part of its budget development process. This metric was introduced as part of the 2021 DSP, so data is tracked from 2021 forward.

The installed cost for a 100kVA pad-mounted transformer (EPI's updated standard transformer for residential use) at current standards is used as a representative value for this metric.

It is evident that EPI has been facing inflationary cost pressures over the past few years. However, EPI continues to exceed econometric expectations based on its Cohort 1 Efficiency Assessment ranking and continued improvement in Actual vs. Predicted Econometric Total Costs. This infers that the industry has been experiencing similar impacts, particularly post-pandemic. The 2024 results will be available in Q3, 2025.

NEW MICRO-EMBEDDED GENERATION FACILITIES CONNECTED ON TIME (SCORECARD MEASURE): TARGET = 90%

Measure: New Micro-embedded Generation Facilities Connected on Time	2020	2021	2022	2023	2024
Entegrus Powerlines	100%	100%	100%	100%	100%

The DSC requires that distributors connect an applicant's micro-embedded generation facility to its distribution system within five business days of the applicant informing the distributor that it has satisfied all applicable service conditions, received all necessary approvals, and provided the distributor with a copy of the authorization to connect from the ESA. The standard is to ensure that 90% of all new micro-embedded generation facilities are connected on time.

This goal has been consistently exceeded since its inception. Moving forward, EPI will work closely with its customers and their contractors to address any connection issues to ensure projects are connected on time.

4.4.3 OPERATIONAL EXCELLENCE – BUSINESS PLAN GOALS MOVING FORWARD

THE CURRENT DSP (2021-2025)

EPI is in its final year of the current DSP (covering from 2021-2025). The DSP delineated a series of analyses and criteria for assessing assets and developing capital programs. EPI uses its GIS system and specialized Engineering software to perform this analysis. Development of the asset management tools within the GIS platform is expected to be a continuous process. As the complexity of the distribution system grows due to electrification, DERs, and Energy storage systems, it is expected that the sophistication of the software used to plan the distribution system will evolve in kind.

To support regulatory requirements, and the next (2026-2030) DSP, an annual joint exercise is performed between the finance, regulatory, and planning departments to track the progress toward, expenditures, and variances to planned work relative to the DSP. This work is performed to track progress and in support of future submissions.

At the time of submission, the DSP is the best plan available based on the most current information.

The inherent dynamic nature of economic growth inevitably means that variations of the plan will occur. Since 2021, system access (cost to connect new customers to the distribution system) costs have risen dramatically due to post-COVID inflation, while the numbers of customers connected each year has surpassed the DSP assumptions for customer growth.

THE NEXT DSP (2026-2030)

The 2026-2030 DSP will be submitted to the OEB in support of the 2026 Cost of Service and will be driven by:

- New OEB Requirements
- Expanded discussion on load forecasting and asset management methodologies.
- Additional coverage of significant supply investments
- Additional discussion on electrification

The ACA was completed at the end of 2023, and the DSP was completed in 2025.

ADDITIONAL INVESTMENTS IN SYSTEM MAINTENANCE

EPI is making additional investments in system maintenance to support reliability and ensure continued alignment with regulatory expectations and support long-term operational goals. Emergency response costs are increasing due to more frequent severe weather events. Vegetation management expenses have risen sharply, resulting in pressure to extend trimming cycles, which increases the risk of outages and equipment damage. Funding is also needed for mandatory inspection and maintenance programs for underground structures and equipment. Finally, modern technologies require additional inspection and maintenance to ensure optimal operation of those assets.

These investments will reduce the likelihood of unplanned outages, support compliance with inspection requirements, and help sustain the long-term health of the distribution system. This sustained approach to maintenance enhances infrastructure resilience and ensures the continued delivery of safe, dependable service.

ADDITIONAL RESOURCES

Engineering expertise is increasingly critical to EPI's operations. The increasing reliance on Smart Grid technology and the increasing expectations from our commercial and industrial customers, especially as related to power quality issues, increases EPI's dependency on experienced and specific engineering expertise. The execution of an Asset Management Plan (i.e. DSP) and projects driven by electrification (i.e. Electric vehicles and electric heat pumps) correspondingly increase the intensity of engineering activity to collect and analyze asset data and translate this information into effective plans.

As noted in the "Inspired and Empowered People" section of this document, growth, coupled with rising customer expectations and the integration of new industry technology has led to significant growth in FTEs. . Also, severe weather is becoming more common and has led to more industry focus on system resiliency and hardening. This has been accompanied by significant staff retirements/departures and focus on succession planning. EPI has continued to focus on recruiting top talent with specific industry skill sets and facilitating internal promotions. Additional lines staff and engineering staff have been added to support these activities and meet all requirements.

Summary of goals:

- Complete the DSP and use it as a tool for the Business Plans.
- Capital investments in the distribution system to improve reliability statistics especially on the poor performing feeders.
- Implement efficiencies in the engineering operations of the SW and NE regions.
- Continue to invest in, train and meet the cyber security requirements.
- Development of standards and execution of projects to support electrification.

4.5 SUSTAINABLE GROWTH

EPI's Core Value of Sustainable Growth encompasses the OEB's RRFE outcome of Financial Performance. The Sustainable Growth Core Value is defined as:

"Delivering sustainable growth for our stakeholders through wise investments."

- Investing wisely
- Maximizing shareholder return
- Serving community/communities
- Proactive in expanding service territory (service area amendments with OEB)
- Reviewing operational and financial risks

4.5.1 APPROACH AND ACTIONS

Sustainable Growth encompasses the concept of making prudent investment decisions in the distribution system that supports customer, and community needs at a reasonable cost. Included in the evaluation of investments in the distribution system are regulatory requirements, reliability standards, and safety for the employees and community. Achieving the regulated return on equity will help EPI invest in the distribution system as needed.

EPI will explore opportunities to expand the service territory, following OEB regulatory guidance, where it is beneficial for current and future customers. Service area amendments may support community growth which in turn will benefit all customers. Further, as described above under Section 2.2, EPI will seek to continue its successful track record of achieving voluntary consolidation with like-minded utilities.

In accordance with its governance practices, the EPI Board of Directors and senior management team must ensure that, as an electricity distributor, EPI's financial viability is maintained while balancing the need for prudent investment with an appropriate level of return for its shareholders.

Additional EPI Finance and Regulatory initiatives include the following:

ENTERPRISE RESOURCE PLANNING (ERP) SYSTEM

As part of its digital transformation strategy, EPI successfully implemented Microsoft 365 Business Central as its

ERP system and Dayforce as its HRIS in November 2024. Since deployment, and continuing through 2025 into 2026, the focus has shifted toward system optimization and enhancement to maximize the value of these platforms. The current enhancement roadmap includes the following initiatives:

- Secure cloud-based portal to improve access to financial reporting and enable self-service capabilities for stakeholders, allowing users to independently view, download, and analyze financial data in real time
- Advanced financial reporting creation using a data-integrated Excel add-in
- Simplified business expense and corporate credit card reporting and reconciliation processes
- Enhanced operational reporting and dashboards to support in-depth variance analysis
- Use of AI-driven tools to identify data trends, forecast cash flow, and automate routine financial queries

2026 COST OF SERVICE APPLICATION

The OEB typically requires that LDCs rebase distribution rates every five years by way of a Cost of Service ("COS") application. However, an exception is made for M&A activity, such as the 2018 merger of EPI (last rebasing 2016) and St. Thomas Energy (last rebasing 2015). Based on the OEB's 2018 merger decision, Entegrus rebasing was deferred until 2026.

The Entegrus 2026 COS is due for filing in August 2025, for rates effective May 1, 2026, and will include proposed rate harmonization of the Legacy Entegrus and St. Thomas rate zones (into a single rate zone). Project work has been underway since early 2023 by a core project team of staff primarily from Regulatory, Finance and System Planning. This is a significant undertaking.

After the application is submitted in August 2025, the discovery phase will commence. During this project phase, management will respond to interrogatories and participate in other regulatory processes related to the application. The discovery phase may run from September 2025 until early 2026.

IESO MARKET RENEWAL PROGRAM (MRP)

In 2017, the IESO announced a project to create new Ontario energy market methodology projected to save $700 million in provincial energy pricing over ten years. MRP results in a day-ahead market, real-time market, and dual-component commodity pricing, marking the largest redesign since the "Market Opening".

Under MRP, the current IESO settlement methodology with LDCs changes. The traditional Hourly Ontario Energy Price shifts to a Day-Ahead Market Ontario Zonal Price (initially uniform across Ontario electrical zones), plus a Load Forecast Deviation Adjustment for discrepancies between forecasted and actual energy consumption. The OEB published Deferral and Variance ("DVA") accounting guidance to align with the IESO settlement changes occurring under MRP. Market trials concluded in July 2024 and end-to-end was completed in Q1, 2025.

MRP successfully launched on May 1, 2025. The Regulatory team have revised IESO submissions and DVAs, in accordance with OEB guidance, as required to reflect the new Ontario electricity price.

4.5.2 KEY MEASURES AND PERFORMANCE DISCUSSION

To measure Sustainable Growth and ensure that EPI is on course, EPI focuses on its measure related to profitability, entitled “Business Plan Regulated Return on Equity.” EPI also tracks three additional measures related to liquidity, leverage, and profitability.

These measures and the associated performance discussion are detailed below.

LIQUIDITY: CURRENT RATIO (SCORECARD MEASURE): TARGET => 1.0

Measure: Liquidity Ratio	2020	2021	2022	2023	2024
Entegrus Powerlines	1.23	1.06	1.08	1.08	1.36

The Liquidity Ratio, also called the Working Capital Ratio, is calculated by dividing Current Assets by Current Liabilities. This metric assesses an organization’s capacity to fulfill its short-term financial obligations. EPI's Liquidity Ratio demonstrates its ability to remain liquid and meet these obligations.

EPI aims to maintain a Liquidity Ratio above 1.0, signifying that it has sufficient resources to cover short-term liabilities. EPI continues to meet this target.

LEVERAGE: TOTAL DEBT TO EQUITY RATIO (SCORECARD MEASURE): TARGET =< 1.5

Measure: Leverage Ratio		2020	2021	2022	2023	2024
Entegrus Powerlines		1.30	1.24	1.25	1.39	1.20

The OEB uses a deemed capital structure of 60% debt and 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt-to-equity ratio of 1.5 (60/40). A debt-to-equity ratio of more than 1.5 indicates that a distributor is more highly leveraged than the deemed capital structure. A high debt-to-equity ratio indicates that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt-to-equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

In late 2024, EPI refinanced its long-term debt portfolio by consolidating all outstanding obligations with TD Commercial Banking. EPI’s goal is to continue to maintain a debt-to-equity structure that closely approximates the deemed 60% to 40% capital mix as set out by the OEB – this is demonstrated by the 2024 debt-to-equity ratio of 1.20 and the projected 2025 and 2025 debt-to-equity ratios of 1.39 and 1.48, respectively. EPI’s Leverage Ratio is consistent with regulated guidelines and provides sufficient capital to fund the proposed DSP investments.

REGULATORY RETURN ON EQUITY ACHIEVED (SCORECARD MEASURE): MONITOR

Measure: Regulatory Return on Equity Achieved		2020	2021	2022	2023	2024
Entegrus Powerlines		8.23%	9.29%	7.85%	8.79%	7.58%

The Regulatory Return on Equity Achieved Measure (“Regulated ROE”) is calculated by dividing Rate-Regulated Net Income by Regulated Deemed Equity (i.e., 40% of Rate Base).

The results above are within +/ 300 basis points of the 9.19% regulated return embedded in distribution rates, as shown on the EPI 2023 Scorecard.

BILL IMPACTS (DSP MEASURE)

EPI Bill Impact Year	Legacy Entegrus Rate Zone			St. Thomas Rate Zone		
	Typical Residential	$ Increase (Decrease)	% Increase (Decrease)	Typical Residential	$ Increase (Decrease)	% Increase (Decrease)
2025	$ 131	$ (0.41)	-0.3%	$ 130	$ 0.20	0.2%
2024	$ 132	$ 3.20	2.5%	$ 130	$ 2.86	2.2%
2023	$ 124	$ 6.77	5.8%	$ 123	$ 4.85	4.1%
2022	$ 119	$ 0.96	0.8%	$ 120	$ 1.62	1.4%
2021	$ 118	$ 0.53	0.5%	$ 117	$ 1.82	1.6%
2020	$ 115	$ 1.30	1.1%	$ 114	$ (1.15)	-1.0%

Note: The above bill impacts are based on a typical total Residential bill using 750 kWh, inclusive of all bill components, including: Commodity, Distribution (including Deferral and Variance Accounts [pass-thru] disposition), Delivery and government regulatory charges.and Ontario Electricity Rebate. However, the rate application increase (decrease) is isolated to only reflect the change in Distribution.

Customer engagement has noted the importance of delivering electricity at reasonable rates. Accordingly, EPI monitors bill impacts by way of two measures: (a) Total Dollar Increase (Decrease) per Rate Application, and (b) Percentage Increase (Decrease) per Rate Application. Although the tracking focus is on Residential bill impacts, EPI also monitors bill impacts across all rate classes.

The bill impacts related to the EPI 2016 Cost of Service Application were flat or declining for most customers. Since 2016, EPI rate increases have been consistent with annual inflation factors (net of productivity factors) published by the OEB, plus or minus Deferral and Variance account (pass-thru) disposition.

EPI monitors these measures throughout the rate application process, including during the development of the DSP, when modifications to the capital expenditure plan are contemplated. Due to the mechanistic nature of the IRM process, bill impacts resulting from contemplated DSP modifications and resulting investments in Rate Base, typically do not take effect until such time as the next rebasing, or when an ICM/ACM is approved in the interim.

The objective of analyzing bill impacts is exercise is to ensure that rate applications do not trigger rate shock and that corresponding total bill impacts greater than 10%. In such cases, mitigating actions would be implemented.

4.5.3 SUSTAINABLE GROWTH – BUSINESS PLAN GOALS MOVING FORWARD

Key 2026 goals related to Sustainable Growth include:

- Refinement of the ERP financial system and HRIS launched in 2024, including adjusting reporting as needed (see detailed points above under ERP System).
- Completion of a high-quality 2026 Cost of Service application and submission to the OEB in August 2025. Completion of high-quality discovery phase responses.
- See Attachment 1 for the EPI 2026-2030 Business Plan financials
- See Attachment 2 for the EPI 2023 Scorecard

5 ATTACHMENT 1: FINANCIAL STATEMENTS

SEE BELOW

Entegrus Powerlines Inc.
2026-2030 Business Plan
Income Statement

	2025P	2026	2027	2028	2029	2030
Distribution Revenue						
Residential	20,939,554	24,077,602	26,021,136	26,801,770	27,605,823	28,433,998
General Service	12,836,814	14,232,702	15,381,525	15,842,971	16,318,260	16,807,808
Net Distribution Revenue	33,776,368	38,310,303	41,402,662	42,644,741	43,924,084	45,241,806
Other Revenue	2,780,916	2,737,684	2,733,320	2,777,457	2,825,794	2,877,371
Net Operating Revenue	36,557,284	41,047,987	44,135,981	45,422,198	46,749,878	48,119,177
Operating Expenses						
Operating and Maintenance	8,262,261	8,707,131	8,968,345	9,237,395	9,514,517	9,799,953
Billing & Collecting	4,780,788	5,373,596	5,534,804	5,700,848	5,871,874	6,048,030
Administration	6,264,897	7,084,688	7,312,212	7,528,543	7,737,303	7,961,896
Depreciation and Amortization	7,655,667	8,054,879	8,454,879	8,854,879	9,254,879	9,654,879
Total Operating Expenses	26,963,613	29,220,294	30,270,240	31,321,665	32,378,572	33,464,757
Operating Income	9,593,672	11,827,693	13,865,742	14,100,533	14,371,306	14,654,420
Financial Expenses						
Interest Expense	5,026,347	5,421,288	5,835,838	6,004,731	6,456,147	6,775,098
Charitable Donations	345,000	630,000	630,000	630,000	630,000	630,000
Total Financing Expenses	5,371,347	6,051,288	6,465,838	6,634,731	7,086,147	7,405,098
Income before Income Taxes	4,222,325	5,776,405	7,399,903	7,465,801	7,285,159	7,249,322
Provision for Income Tax						
Income Tax	618,874	567,243	726,671	733,142	715,403	711,883
Net Income	3,603,451	5,209,161	6,673,233	6,732,660	6,569,756	6,537,439
Regulated Equity (Deemed)	71,668,512	77,013,792	81,221,340	85,175,772	89,072,540	93,130,060
Regulated ROE	5.4%	7.5%	8.9%	8.6%	8.0%	7.6%

Entegrus Powerlines Inc.
2026-2030 Business Plan
Balance Sheet

	2025P	2026	2027	2028	2029	2030
ASSETS						
Current Assets						
Cash	4,885,513	4,154,658	4,447,860	4,483,548	4,118,347	4,358,582
Accounts receivable:						
Accounts receivable	20,500,000	21,209,900	21,771,200	22,148,900	22,738,300	23,345,500
Accounts receivable - unbilled revenue	18,000,000	18,522,800	19,078,500	19,452,400	20,035,900	20,637,000
Inventories	3,500,000	3,570,000	3,641,400	3,714,228	3,788,513	3,864,283
Prepaids	1,500,000	1,545,000	1,591,350	1,639,091	1,688,263	1,738,911
Goodwill	452,040	452,040	452,040	452,040	452,040	452,040
Regulatory assets	1,181,457	1,691,158	3,097,409	2,937,413	2,777,417	2,617,421
Total Current Assets	50,019,010	51,145,556	54,079,759	54,827,619	55,598,779	57,013,737
Property, Plant & Equipment	173,321,064	183,590,525	193,514,127	202,492,663	212,101,702	221,857,158
TOTAL ASSETS	223,340,074	234,736,081	247,593,886	257,320,282	267,700,481	278,870,894
LIABILITIES						
Current Liabilities						
Bank indebtedness	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000
Accounts payable	21,000,000	21,421,000	22,063,600	22,725,500	23,407,300	24,109,500
Due to related parties	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
Current portion of deposits	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
Current portion of long-term debt	1,234,154	1,458,028	1,668,163	1,871,357	2,069,226	2,288,016
Total Current Liabilities	34,234,154	34,879,028	35,731,763	36,596,857	37,476,526	38,397,516
Long-term debt	100,295,614	109,337,586	118,169,423	123,798,066	130,228,841	137,440,825
Employee future benefits	2,998,054	2,998,054	2,998,054	2,998,054	2,998,054	2,998,054
Long-term deposits	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
Derivative instruments	2,473,282	2,473,282	2,473,282	2,473,282	2,473,282	2,473,282
TOTAL LIABILITIES	150,001,104	159,687,950	169,372,522	175,866,259	183,176,702	191,309,677
SHAREHOLDERS' EQUITY						
Capital stock	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623
Share premium	41,232,836	41,232,836	41,232,836	41,232,836	41,232,836	41,232,836
Retained earnings	6,424,793	8,133,954	11,307,187	14,539,846	17,609,602	20,647,041
Hedging reserve	(2,473,282)	(2,473,282)	(2,473,282)	(2,473,282)	(2,473,282)	(2,473,282)
TOTAL SHAREHOLDERS' EQUITY	73,338,970	75,048,131	78,221,364	81,454,023	84,523,779	87,561,218
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	223,340,074	234,736,081	247,593,886	257,320,282	267,700,481	278,870,894

Capital Structure

	2025P	2026	2027	2028	2029	2030
Debt	58.2%	59.7%	60.5%	60.7%	61.0%	61.5%
Equity	41.8%	40.3%	39.5%	39.3%	39.0%	38.5%

Entegrus Powerlines Inc.
2026-2030 Business Plan
Statement of Cash Flows

	2026	2027	2028	2029	2030
OPERATING ACTIVITIES:					
Net income	5,209,161	6,673,233	6,732,660	6,569,756	6,537,439
Add (deduct) non-cash charges:					
Depreciation	8,283,539	8,690,398	9,097,464	9,504,741	9,912,237
Net change in non-cash working capital:					
Accounts receivable	(709,900)	(561,300)	(377,700)	(589,400)	(607,200)
Accounts Receivable - unbilled revenue	(522,800)	(555,700)	(373,900)	(583,500)	(601,100)
Inventories	(70,000)	(71,400)	(72,828)	(74,285)	(75,770)
Prepaids	(45,000)	(46,350)	(47,741)	(49,173)	(50,648)
Regulatory assets	(509,701)	(1,406,251)	159,996	159,996	159,996
Accounts payable	421,000	642,600	661,900	681,800	702,200
Due to related parties	-	-	-	-	-
Net Cash Provided (Used) by Operating Activities	12,056,299	13,365,230	15,779,851	15,619,937	15,977,154
INVESTING ACTIVITIES:					
Additions to property, plant and equipment (net)	(18,553,000)	(18,614,000)	(18,076,000)	(19,113,780)	(19,667,693)
Other capital	-	-	-	-	-
Net Cash Provided (Used) by Investing Activities	(18,553,000)	(18,614,000)	(18,076,000)	(19,113,780)	(19,667,693)
FINANCING ACTIVITIES:					
Long-term debt issued	10,500,000	10,500,000	7,500,000	8,500,000	9,500,000
Long-term debt repayments	(1,234,154)	(1,458,028)	(1,668,163)	(1,871,357)	(2,069,226)
Common dividends paid	(3,500,000)	(3,500,000)	(3,500,000)	(3,500,000)	(3,500,000)
Net Cash Provided (Used) by Financing Activities	5,765,846	5,541,972	2,331,837	3,128,643	3,930,774
Increase (Decrease) in Cash & Cash Equivalents	(730,855)	293,202	35,688	(365,200)	240,235
Cash (Bank Indebtedness) - Beginning Period	4,885,513	4,154,658	4,447,860	4,483,548	4,118,347
Cash (Bank Indebtedness) - Ending Period	4,154,658	4,447,860	4,483,548	4,118,347	4,358,582
Dividend payout ratio	67%	52%	52%	53%	54%

6 ATTACHMENT 2: 2023 SCORECARD

SEE BELOW

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TO: Chairman and Entegrus Powerlines Board Members

FROM: Chris Towne, CFO and VP IT

DATE: August 1, 2025

SUBJECT: Update to Financials in 2026-2030 Business Plan

PURPOSE

To provide a summary of revisions made to budgeted 2026 figures in the Entegrus Powerlines Inc. ("EPI") 2026-2030 business plan financials.

BACKGROUND

The EPI Board approved the company's 2026-2030 business plan on June 10, 2025. As part of the ongoing preparations for EPI's 2026 Cost of Service ("COS") application, various adjustments to the 2026 budgeted figures have been identified based on new information and further review undertaken during the COS process. Accordingly, it is necessary to update the business plan for the 2026-2030 period.

DISCUSSION

The following schedule provides a comparison of the 2026 income statement included in the revised business plan (referred to as "2026 (Revised)") and the version from the previously approved 2026-2030 business plan (referred to as "2026 (Original)"). As a result of these adjustments, net income has decreased by $17k in the revised business plan.

	2026 (Revised)	2026 (Original)	Difference
Distribution Revenue	38,310,303	38,310,303	-
Other Revenue	2,737,684	2,693,346	44,338
	41,047,987	41,003,649	44,338
OM&A Expenses	29,850,294	29,458,796	(391,498)
Operating Income	11,197,693	11,544,853	(347,160)
Interest Expense	5,421,288	5,421,288	-
Earnings Before Income Taxes	5,776,405	6,123,565	(347,160)
Income Tax Expense	567,243	897,542	330,299
Net Income	5,209,161	5,226,022	(16,861)

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 1-SEC-2

[Exhibit 1, Chapter 2, Appendices]

a. How many months of actuals are included in the Bridge Year Data?
b. Please update the Bridge Year Data to include the most up-to-date actuals available and update the 2026 Forecast if required for Appendices 2-AA, 2-AB, 2-BA, 2-JA, 2-JB, 2-JC and 2-K.
c. Please provide actuals for 2023 and 2024 to the same date as provided in part b.

RESPONSE:

a. The Bridge Year Data does not include any actual results.

b. Please refer to the excel file EPI_IRR_1-SEC-2_Attachment 1_20251126. The 2026 Forecast for Appendices 2-AA, 2-AB and 2-BA have been updated in the live Excel version of the Chapter 2 Appendices (EPI_IRR_2026_Filing_Requirements_Chapter2_Appendices_1.0 20251126) to incorporate revised 2025 capital additions and opening 2026 balances that reflect anticipated variances in 2025 capital spending. This evidence update has also been disclosed in response to 1-Staff-1.

   The adjustments to the 2025 capital additions and the 2026 opening balances in Appendix 2-BA reflect categorization variations in the 2025 Bridge Year versus plan based on actual spending to date, described as follows:
   - OEB account 1835 – Overhead Conductors & Devices – decrease of $1.351M versus plan
   - OEB account 1840 – Underground Conduit – increase of $326k versus plan

- OEB account 1845 – Underground Conductors & Devices – increase of $2.488M versus plan
- OEB account 1915 – Office Furniture & Equipment (10 years) - increase of $18k versus plan
- OEB account 2440 – Deferred Revenue – increase of $1.480M versus plan

These changes reflect higher than planned customer-driven system expansion spending and are fully offset by contributed capital. As a result, there is no impact on 2026 Test Year rate base.

c. Please refer to the excel file EPI_IRR_1-SEC-2_Attachment 1_20251126. To compile the 2023 and 2024 YTD actual compensation and OM&A information, EPI pro-rated the full-year expenses by 10/12 and then accounted for known timing differences. This approach was adopted because a formal financial close was not completed for payroll and expense accounts as of October 31, 2023 and 2024. For capital-related historical information, actual expenditures as of October 31, 2023 and 2024 were used, as this data was readily available in EPI's job costing records.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 1-SEC-3

[Exhibit 1, p.91] Entegrus has provided savings as a result of the merger.

a. Please provide any productivity and efficiency measures not associated with the merger for the historical period since the last cost of service applications.
b. Please explain the methodology used to determine any savings, quantify the savings and provide supporting calculations.
c. Please provide details of all productivity and efficiency measures Entegrus is planning to undertake over the next five years. Please quantify the forecasted savings and explain how they were calculated.

RESPONSE:

a. In the earlier part of the Historical Period, EPI focused on operationalizing the merger and realizing the persistent savings of $1.764M described in Exhibit 1, Section 1.11.4. Thereafter, EPI implemented a broad range of productivity and efficiency initiatives, as summarized in the following table (see part c. below).

b. Achieved savings, where applicable, were calculated on a best efforts basis by comparing pre- and post-implementation costs as described in the following table.

c. The table also identifies forward-looking initiatives labelled “Planned/Future”. Forecasted savings, where applicable, are based on the same method described above in part b.

:

Efficiency / Improvement	Status	OM&A or Capital	Savings Type	Application Reference	Comment	Methodology (if applicable)	Embedded in Application
Merger-Related Synergies	Implemented	Both	Persistent	Exh 1, Section 1.11.4	Realized ongoing savings from the 2018 EPI/STEI merger included administrative cost reductions, the consolidation of IT, regulatory and finance functions and in-housing of billing. Persistent cost savings of $1.764M were achieved.	Persistent cost savings of $1.764M were achieved, as described in Exh 1, Section 1.11.4	Yes
Smart Grid / P&C Lab	Implemented	Capital	Avoided Cost	Exh 1, Section 1.9.1	Allows for advance testing of smart grid devices, improving reliability, safety, performance and staff technical proficiency.	Qualitative (methodology not applicable)	Yes
Sectionalization and Distribution Automation	Implemented	Capital	Avoided Cost	Exh 1, Section 1.9.1 Exhibit 2, Attachment 2-C (DSP), Section 5.1.2.3.1.	EPI continues to investment in sectionalization and established additional feeder tie-points, followed by the deployment of smart switches to automate these connections. This approach enables faster isolation of faulted sections, significantly reducing the scope and duration of outages.	Qualitative (methodology not applicable)	Yes
Electronic Funds Transfer (EFT) Implementation	Implemented	OM&A	Efficiency Measure	Exh 1, Section 1.9.2	EPI implemented EFT for vendor payments, moving from paper-based payments to a fully digital approach. This enables consistent and secure payments while strengthening financial controls.	Qualitative (methodology not applicable)	Yes
Integrated ERP and HRIS Platforms	Implemented	Capital	Efficiency Measure	Exh 1, Section 1.9.2	EPI launched Microsoft Dynamics 365 Business Central in 2024, enhancing financial, procurement, and operational workflows with real-time insights. Complementing this, the Dayforce HRIS and payroll platform was also deployed.	Qualitative (methodology not applicable)	Yes
Health & Safety Management System (BIS Safety)	Implemented	Capital	Efficiency Measure	Exh 1, Section 1.9.2	EPI implemented BIS Safety, a cloud-based Health and Safety Management System that centralizes training, compliance tracking, and safety documentation. The platform streamlines inspections, incident reporting, and certification management while providing mobile access to training records and resources for employees.	Qualitative (methodology not applicable)	Yes
Voltage Conversions	Implemented	Capital	Avoided Cost	Exh 2, Attachment 2-C (DSP), Section 3.1.2.2, Section 3.1.4, Section 4.1.3.2.2	EPI continues to advance its Voltage Conversion program, upgrading legacy 4 kV systems to modern 27.6 kV infrastructure. This approach eliminates costly station rebuilds and ensures system capacity and reliability while maintaining prudent lifecycle cost management across the distribution network.	Qualitative (methodology not applicable)	Yes
Control Room, Mapping & GIS Enhancements	Implemented	Capital	Avoided Cost	Exh 2, Attachment 2-C (DSP), Section 3.1.3	EPI enhanced the visualization of its distribution system through enhanced digital mapping and GIS modernization, which supports safe real-time operations and improved visibility for field staff. In 2024, EPI complete a major GIS upgrade, improving data integrity, while making GIS data more accessible on mobile devices and the web.	Qualitative (methodology not applicable)	Yes
Procurement Optimization	Implemented	Both	Efficiency Measure	Exh 2, Attachment 2-C (DSP), Section 3.2.5	EPI is a member of Grid Smart City, a consortium of LDCs that collaborate to advance smart grid technologies and energy solutions. In addition to best practice sharing and other initiatives, Grid Smart City facilitates purchasing consortium bulk purchases of standard equipment (i.e. transformers, IT solutions) which allows for lower unit costs and shorter lead times.	Qualitative (methodology not applicable)	Yes
Cell Phone Contract Renegotiation	Implemented	OM&A	Persistent	n/a	Prior to its contract ending in 2025, EPI negotiated with multiple cell phone providers, culminating in a switch of providers and resulted in savings of approximately $20k per year over a 3-year period from 2025-2028.	Deducted costs of $88k per year under the new provider from costs of $108k per year under the previous provider	No - action identified post budget
Drone-Assisted Inspections	Implemented	OM&A	Avoided Cost	n/a	EPI launched drone-assisted inspections to avoid costs associated with premature asset failure by enabling earlier detection of defects and deterioration. The initiative enhances condition-based maintenance, reducing the likelihood of equipment outages and unplanned replacements.	Qualitative (methodology not applicable)	Yes
AI-Enabled Load Pattern Detection and Proactive Tx Renewal	Planned / Future	Capital	Avoided Cost	Exh 1, Section 1.9.1 Exhibit 2, Attachment 2-C (DSP) Section 5.1.2.3.3.	EPI plans to conduct targeted, proactive transformer replacement using AI-driven at-risk load detection. As more customers adopt electric vehicles, install solar panels, and change how they use electricity, increasing demands are being placed on the distribution system. The AI model, developed from academic research and trained on EPI smart meter data, identifies at-risk units for engineering validation and targeted renewal.	Qualitative (methodology not applicable)	Yes
Customer Mobile App	Planned / Future	Capital	Efficiency Measure	Exh 1, Section 1.7.3	EPI plans to launch a customer mobile application to facilitate customers reviewing their account information, seeing outages and reporting outages.	Qualitative (methodology not applicable)	Yes
Satellite-Based Vegetation Management Program	Planned / Future	OM&A	Avoided Cost	Exh 1, Section 1.7.3, Exh 1, Section 1.9.1 Exhibit 2, Attachment 2-C (DSP), Section 3.2.1.2.1.	EPI plans to use satellite-based vegetation management to create detailed models of vegetation encroachment, enabling smarter, risk-focused trimming and reducing outages from vegetation contacts.	Qualitative (methodology not applicable)	Yes
Website Overhaul	Planned / Future	Capital	Efficiency Measure	Exh 1, Section 1.7.2	EPI plans to undertake a complete overhaul of its website in 2026. This initiative will improve how customers locate essential information, including public safety, billing and self-service features. The redesign will integrate modernized technology to better support customer needs and expectations.	Qualitative (methodology not applicable)	Yes
Board Portal Platform	Planned / Future	OM&A	Persistent	n/a	EPI plans to evaluate alternative Board Portal Platform solutions. Transitioning to a new platform is expected to reduce licensing costs from $28k in 2025, to $21k in 2026 and $15k annually thereafter, resulting in savings of $7k in 2026 and $10k–$15k annually thereafter.	Deducted costs of $21k per year under the new provider from costs of $28k per year under the previous provider, effective May 1, 2026. Thereafter is based on full year	No - action identified post budget
Work Management System	Planned / Future	Capital	Efficiency Measure	Exh 2, Attachment 2-C (DSP), Section 5.1.1.5.4 Exh 4, Section 4.3.4	EPI plans to implement a Work Management System (WMS) to enhance resource planning, workflow standardization, and visibility across departments. Currently in the discovery phase, the initiative aims to enhance scheduling, tracking, and execution of maintenance, capital, and trouble call activities through a centralized digital platform.	Qualitative (methodology not applicable)	Yes

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 1-SEC-4

[Exhibit 1]

Please provide copies of all benchmarking studies, reports, and analyses that Entegrus has undertaken or participated in since the filing of its last rebasing applications, that are not already included in the Application.

RESPONSE:

All benchmarking studies, reports and analyses that EPI has undertaken or participated in are included in the Application, except for the 2025 MEARIE Management Salary Survey, which EPI has provided as Attachment 1 to this response. As described in the accompanying Interrogatory Responses and Confidentiality Request letter dated November 26, 2025, pages 5-8, pages 28-30 and Appendix C of the attachment have been redacted.

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1-SEC-4

Attachment 1

ECKLER

The MEARIE Group

The MEARIE Group

2025 Management Salary Survey of Local Distribution Companies

September 2025

Survey Administrators: Eckler Ltd.
Confidential and Proprietary

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Introduction

The MEARIE Group is pleased to present this report of the 2025 Management Salary Survey of Local Distribution Companies (LDCs).

In today's competitive talent market, Local Distribution Companies (LDCs) are challenged with establishing and maintaining competitive, yet affordable, compensation programs and policies. Although inflation is slowing down, it continues to present challenges for compensation programs and policies, as do changing workplace landscapes with multiple generations having differing priorities, pending pay transparency legislative requirements, and an increased focus on total rewards packages with non-traditional benefits. The MEARIE Group established the Management Salary Survey of Ontario's LDCs to assist you in understanding the competitive landscape and support your efforts in developing pay practices that attract, motivate, and retain high quality, high performing employees.

The survey was administered in 2025 in partnership with Eckler Ltd., who are experts in developing and managing salary surveys. Changes to the 2025 survey included providing additional compensation market statistics (deciles), where available in the job data tables. In addition, questions regarding pay transparency and the adoption of "living wage employer" compensation rates are now included in the survey.

The survey was launched in May 2025 and 32 organizations provided completed survey materials to inform this report. The report is divided into two parts:

Part 1 – Study Report (this document)
- Profile of survey participants
- Overview of salary projections for 2026 salary planning and other market trends and programs
- Information on benefits programs and offerings
- Summary of the survey methodology and definitions of terms
- Job descriptions for the 56 benchmark jobs

Part 2 – Benchmark Job Tables (provided as a separate Excel file)
- Reporting based on the number of customers, number of employees, region, and revenue
- Reporting up to total cash compensation, including annual incentive or variable pay information

Confidentiality Policy

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Management Salary Survey ("Survey"), as well as the Survey Administrator and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission for a Survey. This will result in the LDC's data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the Survey to determine the relevance of Survey data cuts (e.g., by geography or size).

All of the information obtained through this Survey will be treated with the utmost confidentiality. Data will be reported on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified/attributed. Standards for minimum number of data will be strictly enforced to ensure confidentiality. Neither the Survey Administrator nor The MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

Survey results will be reported only to those LDCs who participate in the Survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the Survey benchmark positions as they are able and provide data for all incumbents of matched positions. **All participants must consider this information as strictly confidential.**

The results of a Survey will not be disclosed/sold to or shared with organizations that have not participated in that Survey, whether by The MEARIE Group or the Survey Administrator or Survey participants. **Participants may not share the Survey reports/results with non-participant LDCs or any entity under any circumstances.**

The data collected for a Survey will also be included in the Survey Administrator's compensation database. Information in the Survey Administrator's database is maintained with the highest standards of confidentiality; analysis and reporting of data is on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified or attributed.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law. However, LDCs may not disclose the existence or results of a Survey to any regulatory body (or other person) unless compelled by law to do so, and if an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required. In such circumstances, the LDC will take such steps as The MEARIE Group reasonably requests or will co-operate with respect to any steps The MEARIE Group and/or Survey Administrator reasonably wishes to take, to contest or limit the scope of the disclosure.

The MEARIE Group will not be liable for breaches by participating LDCs or the Survey Administrator of this Confidentiality Policy. By registration & participation the LDC is bound to this Confidentiality Policy.

Survey Overview

Benchmark Positions

This survey covers 56 benchmark jobs that are representative of the functions within The MEARIE Group's member organizations. No changes were made to the benchmark jobs in 2025. The job descriptions for each benchmark are provided in **Appendix C.**

Job Family	Job Code	Job Title
[redacted]		

Job Family	Job Code	Job Title
[redacted]		

Job Family	Job Code	Job Title
[redacted]		

List of Participants

All Ontario LDC MEARIE members were invited to participate in the survey, and 32 organizations submitted completed survey materials:

[redacted]

Participant Profile

The profile of the 32 participants is summarized in the tables below. The figures are reported as provided by the participants and have not been verified.

LDC Profile (N = 32)	P25	P50	P75	Average[2]
Operating Budget, excluding cost of energy (millions)	$8.2	$16.4	$31.3	$22.1
Operating Budget, including cost of energy (millions)	$44.3	$92.9	$156.8	$143.6
Number of Employees (full-time equivalent)	31.0	64.0	125.8	95.6
Number of Union Employees (full-time equivalent)	13.0	38.0	83.8	58.6
Number of Non-Union Employees (full-time equivalent)	9.8	23.5	47.5	37.1
Number of Customers	15,501	32,695	60,475	48,291
Gross Revenue, including cost of energy (millions)	$45.5	$95.5	$171.2	$152.1
Gross Revenue, excluding cost of energy (millions)	$9.8	$24.1	$39.6	$31.1
Regulated Gross Revenue[1]	95.5%	97.9%	99.0%	96.6%
Unregulated Gross Revenue[1]	1.0%	2.1%	4.5%	3.4%

1. Twenty-three (23) of the 32 participants indicated there is a split between regulated and unregulated gross revenue; the data provided for this statistic is only for the organizations that indicated the split. Nine (9) organizations are not reporting blended revenue.
2. Where averages are significantly higher than the median (or P75) of the market, this indicates a small number of observations with a large number which skew the average data high.

All thirty-two (32) participants reported that their fiscal year-end is December.

Participants with non-regulated operations were also asked to report the revenue of their sister companies and the number of employees. Overall, 12 organizations reported data from sister companies. Where organizations did not have direct employees generating the revenue, this was due to administration of non-employee contractors, or, overseeing other staff not within the LDC and revenue sharing arrangements.

Sister Profile (N = 12)	P25	P50	P75	Average[1]
Total Revenue (millions)	$1.2	$2.4	$8.5	$21.1
Number of Employees (full-time equivalent)	2.0	4.0	27.5	25.2

1. Where averages are significantly higher than the median (or P75) of the market, this indicates a small number of observations with a large number which skew the average data high.

Salary Administration

Salary Adjustments

Compensation ranges, also known as salary frameworks or salary structures, are the guidelines by which companies administer compensation. These frameworks may be single job rates, step rate systems, salary ranges, or broad bands. Typically, compensation ranges are adjusted based on economic factors on a regular basis (most commonly annually). Actual compensation, or salaries paid, is the actual amount paid to employees within the role. The actual compensation of an incumbent is typically within the salary range and their position in the range/steps varies with tenure, experience and often, performance.

Organizations were asked how they adjusted salary ranges and actual salaries in 2024 and 2025, and what they are forecasting for 2026.

Salary Range Adjustments

The most common month for salary range adjustments is January, followed by April. The table below shows the average salary range adjustments, excluding zeros. Survey participants who have budgeted or estimated for next year (N = 12) plan to increase salary ranges in 2026 by an average of 2.96%.

Eckler's 2025 Compensation Planning Survey (N=326) indicated an average salary range adjustment of 3.2% in 2025 and predicts 3.1% nationally and 3.0% in Ontario in 2026, suggesting that survey participants may lag national salary adjustments.

Year	CEO	Executive	Director	Management	Professional/ Technical	Admin	Overall
2024 (N=29)	3.30%	3.39%	3.23%	3.31%	3.14%	3.16%	3.24%
2025 (N=29)	3.00%	3.09%	3.21%	3.20%	3.15%	3.09%	3.14%
2026 (N=12)	3.15%	3.15%	2.83%	2.92%	2.85%	2.85%	2.96%

Organizations have indicated that salary range adjustments will be adjusted at a lower percentage in 2026 in comparison to 2024 and 2025. This correlates with the reducing inflationary pressures in the economy as the reductions in the Bank of Canada rate and monetary policy take effect. Historically, organizations have adjusted ranges annually, or even less periodically (i.e., every 2 or 3 years with market review).

Actual Salary Increases

The most common month of actual salary increases is January, followed by April. The below table shows the average actual salary increases. No organization has reported plans to freeze actual base salaries.

Survey participants are planning to increase salaries in 2026 by an average of 3.09%.

Eckler's 2025 Compensation Planning Survey (N=390) indicated an average salary adjustment of 3.4% in 2025 and predicts 3.3% nationally and 3.2% in Ontario in 2026, suggesting that survey participants may lag national salary adjustments.

Year	CEO	Executive	Director	Management	Professional/ Technical	Admin	Overall
2024 (N=31)	4.27%	4.09%	3.80%	3.80%	3.64%	3.65%	3.87%
2025 (N=31)	3.63%	3.63%	3.49%	3.53%	3.51%	3.53%	3.55%
2026 (N=15)	3.12%	3.12%	3.05%	3.12%	3.08%	3.08%	3.09%

Actual salary budgets are generally moderately higher than salary range adjustment values which consider that incumbents receive merit adjustments, or movement in range, in addition to overall economic adjustments. For the survey participants, the overall average differential between actual salary budget and salary range is relatively small and is shrinking (0.63% in 2024, 0.41% in 2025, 0.13% in 2026) versus broader industrial surveys where the differential is typically closer to 0.75% - 1.0%.

Incentive Programs

Performance Factors

For organizations that have a broad-based annual incentive plan in place, participants were asked to provide the weighting of factors that are used to determine actual bonus payouts. Executives and senior management are typically more heavily weighted toward corporate performance, while middle management, professional, and administrative jobs are typically more heavily weighted toward individual performance. Team/department factors are not commonly used, with only 5 participants reporting a weighting for team/department performance used for some employee categories.

The below table reports the average weighting of each performance metric, by employee category.

Performance Factor	CEO (N=22)	Executive (N=22)	Director (N=19)	Management (N=18)	Professional / Technical (N=16)	Admin (N=16)
Corporate	62.4%	54.7%	45.0%	38.2%	32.8%	32.2%
Individual	28.6%	34.0%	42.1%	48.2%	58.5%	59.1%
Team/ Department	3.8%	6.1%	6.8%	7.2%	3.1%	3.1%
Other	5.2%	5.2%	6.1%	6.4%	5.6%	5.6%

Note: percentages may not add up to 100% due to rounding.

The most common plan for all employee categories is 50% equal weighting between corporate and individual performance.

Incentive Opportunity Range

Target-based incentive programs typically have a minimum level of performance that must be achieved to receive an incentive payout. If that threshold level of performance is not achieved, then there is no payout. Conversely, target-based incentive programs typically also have a maximum level of payout, where regardless of how much an employee exceeds their performance targets, the payout will not be any higher than the maximum. Between the payout at threshold performance and the maximum payout, incentive plans typically increase the level of payout as the performance levels also increase.

For example, if a job has an incentive target of 20% of base salary and the payout at the threshold level of performance is half of the target, when the threshold level of performance is achieved, the payout will be 10% of base salary. If the maximum incentive is 2X the target, then the payout will be capped at 40% of base salary. Of the organizations reporting, 8 indicated a maximum incentive value but no threshold level.

The typical maximum payout is 1X target, and the typical payout at the threshold level of performance is 0.5X target. In the broader market, it is more common to see higher maximum bonus levels as a multiple of target, especially at the senior management and executive levels. Where an organization provides a maximum incentive value in excess of 1X target, the most common plan is 1.5X.

The table below reports the average maximum incentive and average incentive at the threshold level of performance, as a multiple of the target, by employee category.

Incentive Payout Range	CEO	Executive	Director	Management	Professional/ Technical	Admin
Maximum Payout	(N=18)	(N=18)	(N=17)	(N=17)	(N=15)	(N=15)
	1.32X	1.32X	1.23X	1.23X	1.27X	1.27X
Payout at Threshold Level of Performance	(N=10)	(N=10)	(N=10)	(N=10)	(N=9)	(N=9)
	0.56X	0.56X	0.58X	0.59X	0.54X	0.54X

Compression Policies

Participants were asked if they have a formal salary compression program in place. Only 15% of participants (5 of 32) reported that they do have a formal program.

Specific jobs affected include Line Supervisor and Operations Manager, though generally it is all supervisory jobs or management roles with a union direct report (most often cited as lines, metering, planning or other operational roles) where the negotiated rates can create compensation compression.

The typical minimum salary differential between supervisory roles and their direct reports is 10% (N=4).

Line Supervisors – Overtime Compensation

The direct supervisor of unionized staff is typically called the “Line Supervisor”. Most organizations (65%) (20 of 31 respondents) reported that Line Supervisors receive overtime compensation. The organizations that do not offer overtime to Line Supervisors typically do offer other compensation, most commonly time in lieu is provided. Organizations may also have blended programs where time in lieu is provided, and overtime can be provided in exceptional circumstances to line supervisors or stand by compensation.

The table below reports the average annual amount of overtime paid to the Line Supervisors and the average paid to union staff. Eleven (11) organizations were able to provide average annual overtime dollar amounts for Line Supervisors and 12 organizations provided the average annual overtime dollar amounts for Union Staff.

Position	P25	P50	P75	Average
Line Supervisor (N=11)	$6,950	$21,000	$37,157	$31,816
Union Staff (N=12)	$14,375	$19,557	$26,949	$28,708

Both the Line Supervisor (N=20) and the Union Staff (N=24) roles typically have an overtime and/or on call compensation rate of 2X regular base salary.

Participants were asked if any additional staff other than front-line supervisor roles are eligible for overtime compensation. Out of the 6 organizations that offer overtime to other roles, typically all union and/or non-management staff that are eligible for overtime.

Line Supervisors – Team Size

The table below shows the team sizes for field-based teams, i.e., the number of union roles per supervisor. The most common team size is 10 direct reports.

Team Size (N=29)	P25	P50	P75	Average
Union Roles per Supervisor	8	10	11	9

Line Supervisors – Company Vehicles

68% of LDCs (21 of 31 respondents) indicated that a company-owned or leased car is provided to supervisors for work purposes.

- Twenty-one (21) organizations provided information about car storage. 86% of these organizations indicated that company cars can be stored at the employee's home and 14% indicated that company cars are stored at their work location.
- Nineteen (19) organizations provided information about personal use of company cars. 47% (9 of 19) of these organizations allow some level of personal use of company cars.
    - Of these 19 organizations, 74% have a mileage tracking system in place for personal use of company cars. The most common method used to track mileage of personal use of company cars is a logbook.
    - Nineteen (19) organizations provided details on limitations of personal use of company cars. 32% indicated that employees can not use company cars for any personal use, 26% indicated that employees can use company cars for personal use with no limitations or within reason, 21% indicated that employees can use company cars to drive to and from work only, 16% indicated that employees can use company cars for local driving only or with no extensive kilometre usage, and 5% indicated that only the employee can drive the company car.
- Eight (8) organizations provided taxable benefit amounts for company cars, and the data is provided in the table below. Where averages are higher than the median (or P75) of the market, this indicates a small number of observations with a larger number which skew the average data higher. In 2024, 10 organizations reported a median value of $7,100 and an average of $10,668.

Taxable Benefit (N=8)	P25	P50	P75	Average
Reported Amount	$5,165	$7,610	$13,714	$9,554

Non-Regulated Operations

Some participants in this survey earn additional revenue via non-regulated revenue channels. This section discusses the details of these non-regulated operations.

Non-Regulated Revenue

43% of organizations (13 of 30) indicated that they do not have any non-regulated revenue, 40% of organizations indicated that the non-regulated revenue is structured as a separate company, and 17% indicated that non-regulated revenue is embedded within the organization.

Of the organizations reporting some non-regulated revenue, 16 provided details around the how non-regulated revenue is supported.

Non-Regulated Revenue	Yes	No
Full time dedicated sales staff	31%	69%
Full time dedicated non-sales staff	50%	50%
Regulated company provides corporate services for a fee	81%	19%
Shared staffing arrangement with regulated company	56%	44%

Key Performance Indicators

Participants that have non-regulated sources of income were asked what the Key Performance Indicators (KPIs) for the business are, as well as the proportion of each used in incentive and/or performance measurement. The below table summarizes the prevalence. There was insufficient data provided to report the average scorecard weighting of each KPI.

Key Performance Indicator	KPI Used (% Yes) (N=8)
Earnings / Net Income	63%
Other Financial Metric	37%
Innovation: New Product / Service Offering / Development	25%
Customer: Retention/New	50%
Other	88%

Of the organizations that use “other” KPIs, the most common descriptions included people initiatives and operations growth.

Forecasting future non-regulated business, 11 organizations provided insights. 36% (4 of 11) are seeking to maintain current levels, 9% (1 of 11) are seeking to decrease from current levels, and the remainder (55%) are seeking opportunities or targeting growth. Of those seeking to grow, only 3 of the 6 have defined growth targets, with an average of 13%.

Engineer Compensation

Several organizations (45%, 13 of 29 respondents) differentiate compensation for engineers-in-training / P.Eng candidates. Generally, engineers can expect a pay increase once they have achieved the designation.

Where compensation is differentiated, most commonly (69%, 9 of 13 organizations), engineers-in-training are paid on different salary grids/ranges than engineers with their P.Eng designation. Once the designation is achieved, the engineer moves to the licensed engineer grid/range, which is higher than the engineer-in-training grid/range. In other cases, engineers-in-training and licensed engineers are on the same pay band, however, engineers-in-training cannot achieve full job rate until they have achieved the P.Eng designation.

Workplace Strategies

Living Wages

This year, organizations were asked if they are living wage employers. Living wages are an alternative to consider for organizations which study the hourly wage a worker needs to earn to cover their basic expenses and participate in their community. The living wage rate is often significantly higher than the legislated minimum wage.

Living wages are determined annually by organizations, such as the Ontario Living Wage Network, who utilize a formula which includes adjustments for local area expenses and assumed living expenses. For example, in 2024 the published living wage rate for the Greater Toronto Area is $26.00 versus the Employment Standards Act general minimum wage of $17.20

Only 9% of organizations (3 of 32 respondents) have a formal living wage policy. Of those organizations, 2 stated they pay living wages to all their employees except students, and 1 stated they pay living wages to all employees, including students. Six (6) respondents stated that while they do not have a formal policy in place, all wages are currently above the living wage rates for their geographic area.

Pay Transparency

With recent legislation changes, Ontario's Employment Standards Act has undergone several changes, with a major change expected to take effect in January 2026 regarding pay transparency on job postings. Other transparency requirements in recruiting have already taken effect and additional reporting, such as disclosure of AI use, will be required soon. Though the vast majority of LDCs (31 of 32, or 97%) report no use of AI in current recruitment and selection processes.

Other jurisdictions across Canada, such as British Columbia, have also adopted legislation with respect to Pay Transparency, which continues to be implemented in a phased-in approach by organization size.

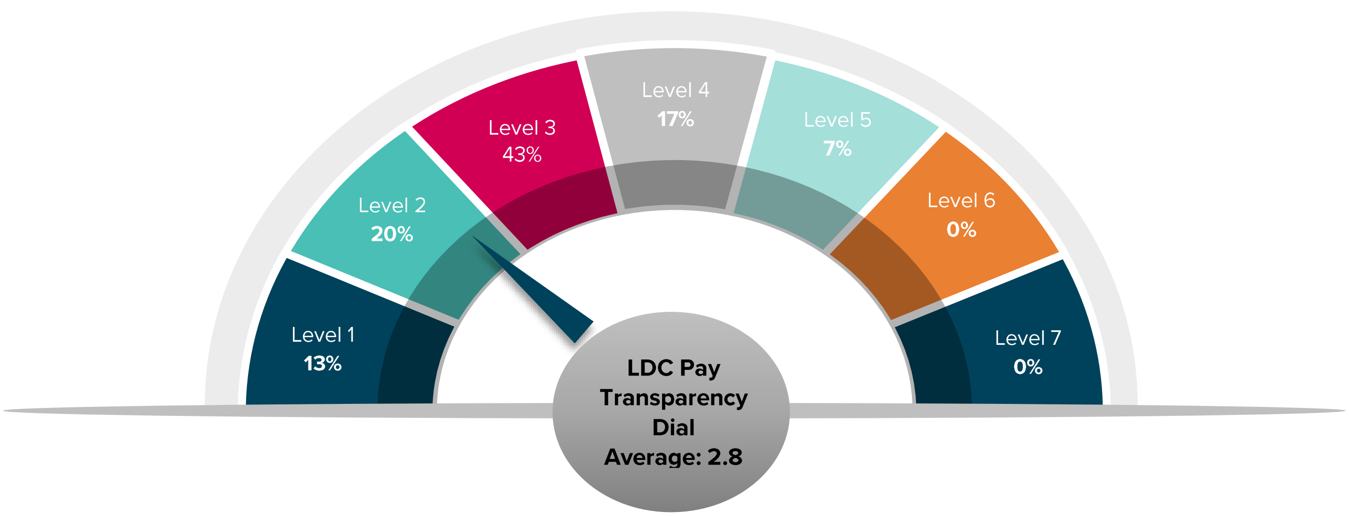
The table below summarizes survey responses regarding the current level of pay transparency on job postings. Most commonly, organizations are not yet disclosing salary ranges on job postings.

Job Posting Pay Transparency Level	% of Responses (N=32)
Salary ranges are posted only on union roles	25%
Salary ranges are not disclosed	41%
Hiring ranges are already posted on all jobs	9%
Salary ranges are already posted on all jobs	13%
Hiring ranges/Starting rates are already posted on union roles	6%
Other	6%

Participants were asked to rank on a scale of 1 to 7 their status with respect to compensation transparency as follows. Contrasting the responses from the survey participants this year and last year with a broader survey sample, LDC organizations are less transparent overall than broader industry.

Internal Pay Transparency Level	2024 MEARIE Survey (N=33)	2025 MEARIE Survey (N=30)	Eckler 2026 Salary Planning (N=412)
Level 1 = Employees know what their own pay is.	24%	13%	17%
Level 2 = We have set processes / documentation in place providing guidelines in how we determine pay (i.e., philosophy, conducting market reviews, survey participation, etc.).	12%	20%	22%
Level 3 = Employees know where their salary falls within their grade level/range.	36%	43%	12%
Level 4 = Managers are equipped to provide guidance and interpretation on employee salary and support career progression.	15%	17%	17%
Level 5 = We publish our salary ranges/grade levels internally for select employee groups (i.e., people leaders).	6^	7%	11%
Level 6 = We publish salary ranges/grade levels internally for all employee access.	0%	0%	13%
Level 7 = Full disclosure and transparency on employee salary and core pay administration practices.	6%	0%	8%

Data may not sum to 100% due to rounding.



The weighted average for the Eckler 2026 survey, which is a sample of 412 organizations in a variety of sectors, has a weighted average of 3.6, indicating that LDCs may be less transparent overall than other organizations at 2.8. Eckler survey data from 2024 to 2025 indicates that organizations overall have become more transparent across Canada.

With the upcoming changes to pay transparency requirements in Ontario, survey participants were asked about their pay transparency practices. However, the pay transparency requirements are only applicable to organizations with more than 25 employees; 7 of the survey participants report less than 25 FTEs.

The table below summarizes participants' current levels of practice in place. Most commonly, organizations do not yet have any pay transparency practices in place, though 6 organizations that do not have practices in place are also below the threshold for reporting.   Data are provided for all organizations as well as for organizations with 25 or more employees only.

Pay Transparency Practices	**% of Responses** (N=28)	**% of Responses, >25 FTE** (N=22)
Finalizing practices	36%	45%
Practices already in place	14%	15%
None	46%	32%

Benefits Policies

Company Cars

Company-Owned Cars and Car Allowances

Where organizations provide a car allowance or company car as a perquisite (i.e., not cars provided for business use only), they are most commonly offered as a monthly allowance. The below table shows the monthly allowance amounts reported, by employee category. Staff below director level are not typically receiving car allowances.

Monthly Car Allowance	P25	P50	P75	Average
CEO (N=16)	$775	$1,000	$1,056	$976
Executive (N=12)	$608	$750	$813	$740
Director (N=5)	*	$600	*	$517

**Insufficient data to report.*

Reimbursement Rates

The table below shows the reimbursement rates reported for using a personal automobile for business purposes. The typical rate is 72 cents per kilometre, reported by 31 organizations. This is aligned with the Canada Revenue Agency rate for 2025 for the first 5,000 km driven by an employee who uses their personal vehicle for business purposes (72 cents per kilometre). CRA reduces the rate from 72 cents per kilometre down to 66 cents for each additional kilometre in excess of 5,000 km.

Mileage (N=31)	P25	P50	P75	Average
Reimbursement Rate ($/km)	$0.64	$0.72	$0.72	$0.67

Participants were also asked to provide details regarding reimbursement for travel, meals, or other allowance coverage. Common themes identified are:

- Twenty-two (22) organizations provided information on meal reimbursements.
  - The average daily meal allowance reported was $94.34 (N=12). Some organizations specify an amount/maximum for specific meals where breakfast is the lowest cost meals and dinner is the highest cost meal allowance.
  - Ten (10) organizations reported that meals are reimbursed based on the actual costs incurred.
- Sixteen (16) organizations reported that travel and expenses are reimbursed, most commonly based on the actual costs incurred.

- Two (2) organizations specified that they pay for highway tolls and parking, in addition to their mileage reimbursement policy. Though, with authorization it is likely that these expenses are covered by more organizations if they are determined to be reasonable.

Perquisites

Additional Benefit Level

Participants were asked to provide the basic and supplemental life insurance coverage offered to senior management, where the organization pays the premium. Generally, more organizations are providing a higher level of life insurance coverage to senior-level roles. The table below provides the coverage level expressed as a multiple of base salary.

Employee Level	Basic Coverage	Supplemental Coverage
CEO	Range: 1.0 – 3.0 Average: 1.6 N = 18	Range: 2.0 – 4.0 Average: 2.8 N = 5
Executive	Range: 1.0 – 2.0 Average: 1.6 N = 18	Range: 2.0 – 4.0 Average: 2.8 N = 5
Director	Range: 1.0 – 2.0 Average: 1.6 N = 17	Range: 2.0 – 4.0 Average: 2.8 N = 5
Management	Range: 1.0 – 2.0 Average: 1.6 N = 17	Range: 2.0 – 4.0 Average: 2.8 N = 5

Education Reimbursement

Eighteen (18) organizations reported a policy for post graduate programs. Common themes of the plans included:

- Seven (7) organizations reported that employees must be pre-approved for education programs.
- Six (6) organizations report that the program must be beneficial and add value to the organization.
- Three (3) organizations specified that their post graduate programs policy covers all employees, while one (1) organization specified that it is only offered to management and executives.

Nineteen (19) organizations provided information on the qualification criteria for post graduate programs:

- Ten (10) organizations reported that post graduate program must be pre-approved.
- Eight (8) organizations reported that the post graduate program must be a job requirement and/or beneficial for the employee's current or future position.
- Four (4) organizations reported that only specific roles are eligible for the programs.
- Four (4) organizations reported that education programs must be taken through an accredited establishment.

Five (5) organizations reported that there is no maximum amount that will be reimbursed for post graduate programs. Eight (8) organizations reported specific annual maximum amounts, shown in the table below.

Education Reimbursement (N=8)	P25	P50	P75	Average
Annual Maximum	$2,375	$2,750	$4,000	$3,025

Eighteen (18) organizations provided information on any conditions of the subsidy for the employee to repay all or part of the subsidy if they leave the company within a specified time period:

- Fourteen (14) organizations reported that employees must stay for a certain period to avoid repayment clauses. The years of service required following education provisions range from 1 up to 5 years to require no repayment, with the average and most common policy as 3 years (N=10).

- Seven (7) organizations reported that their repayment policy requires different percentages of repayment based on years of service.

Club Membership – Fitness/Wellness

The table below reports the annual value of fitness/wellness club membership fees per employee, by employee category. Most organizations (87% or 13 of 15) provide the same value for all employee levels, with a minority of organizations (13% or 2 of 15) providing a higher level of benefit for more senior staff.

Employee Category	P25	P50	P75	Average
CEO (N=15)	$250	$300	$400	$389
Executive (N=15)	$250	$300	$400	$345
Director (N=15)	$250	$300	$400	$329
Management (N=15)	$250	$300	$400	$329
Professional/ Technical (N=15)	$250	$300	$375	$325

Health Care Spending Account

The below table reports the annual value of health care spending accounts per employee, by employee category.

Employee Category	P25	P50	P75	Average
CEO (N=14)	$831	$1,125	$2,000	$1,443
Executive (N=14)	$756	$1,000	$2,000	$1,346
Director (N=13)	$750	$1,000	$1,000	$921
Management (N=11)	$625	$775	$1,000	$788
Professional/ Technical (N=10)	$500	$650	$1,000	$717

Executive Medical Plan

The below table reports the annual value of executive medical plans per employee, by employee category. No data are available for management level and below.

Employee Category	P25	P50	P75	Average
CEO (N=6)	*	$3,000	*	$2,597
Executive (N=5)	*	$3,000	*	$2,516
Director (N=3)	*	*	*	$1,848

**Insufficient data to report*

Personal Computer / Internet Connection for Home Use

The below table reports the annual value of personal computers and/or internet connection for home use per employee, by employee category.

Employee Category	P25	P50	P75	Average
CEO (N=5)	*	$350	*	$810
Executive (N=5)	*	$350	*	$810
Director (N=5)	*	$350	*	$590
Management (N=5)	*	$350	*	$590
Professional/ Technical (N=5)	*	$350	*	$590

**Insufficient data to report*

Other Perquisites

Participants were also asked about other perquisites that were not reported as commonly offered. Four (4) organizations pay for employees' membership/professional dues, though there is insufficient data to provide an average value of the coverage/reimbursement provided. Provision of hardware (personal computer, cell phone) was alco cited as a perquisite.

Vacation

Vacation Entitlement – by Level

The below tables report the years of service required to be eligible for the number of vacation weeks as indicated in the headers of the table. It is important to note that many organizations may have an enhanced vacation schedule such that senior staff are automatically awarded more weeks of vacation entitlement, however, many organizations also may have the same vacation policy across all levels. In addition, organizations may recognize previous years of applicable experience when hiring staff as part of their salary administration and hiring policies.

CEO	2 Weeks (N=13)	3 Weeks (N=19)	4 Weeks (N=23)	5 Weeks (N=27)	6+ Weeks (N=28)
Average	Start	2	6	11	15
Median	Start	3	7	13	18
Most Common	-	-	Start	16	25

Executives	2 Weeks (N=13)	3 Weeks (N=19)	4 Weeks (N=24)	5 Weeks (N=29)	6+ Weeks (N=28)
Average	Start	2	6	10	17
Median	Start	3	7	10	19
Most Common	-	-	-	Start	25

Directors	2 Weeks (N=14)	3 Weeks (N=22)	4 Weeks (N=29)	5 Weeks (N=29)	6+ Weeks (N=28)
Average	Start	2	6	12	18
Median	Start	1	7	14	19
Most Common	-	-	Start	15	25

Management	2 Weeks (N=15)	3 Weeks (N=27)	4 Weeks (N=30)	5 Weeks (N=30)	6+ Weeks (N=28)
Average	Start	1	6	13	20
Median	Start	1	8	14	21
Most Common	-	Start	9	15	25

Professional/ Technical	2 Weeks (N=20)	3 Weeks (N=29)	4 Weeks (N=30)	5 Weeks (N=30)	6+ Weeks (N=28)
Average	Start	2	8	15	22
Median	Start	2	8	15	25
Most Common	Start	3	9	15	25

Unused Vacation

Participants were asked about their policy on annual vacation entitlement that is not fully utilized before the end of the year. All 32 survey participants responded to this question.

- 63% of organizations reported that a maximum amount of unused vacation can be carried over.
- 25% of organizations reported that unused vacation entitlement may be carried over, subject to a maximum total accumulated balance.
- 13% of organizations reported that all unused vacation entitlement may be carried over with no restrictions.
- No organizations reported "use it or lose it" policies where vacation cannot be carried over.

When carrying vacation over, policies vary with respect to when the carried vacation must be used. 30 organizations provided information with respect to carried vacation entitlement time frames.

- Seven (7) organizations have no time limit for outstanding vacation days that must be used.
- Thirteen (13) organizations require employees to use carried-over vacation days within six months or less.
- Ten (10) organizations require employees to use carried-over vacation days within twelve months.

Of the organizations that allow unused vacation entitlement to be carried over with restrictions, twenty-three (23) organizations have a specified maximum number of days in their carry-over policy.

Vacation Carry Over (N=23)	**P25**	**P50**	**P75**	**Average**
Maximum Days	5	5	10	9[1]

1. Where averages are significantly higher than the median (or P75) of the market, this indicates a small number of observations with a large number which skew the average data high.

Participants were asked to provide details on any variations in vacation carry-over policies by level or length of service. Generally, there are approval requirements that enable additional carry-over balances in excess of policy that can be applied in unique circumstances.

Benchmark Positions Survey Results

The benchmark job tables are provided as a separate Excel file. The file includes the statistical data for the survey benchmark jobs for up to total cash compensation, including annual incentive or variable pay information.

Reporting is available based on number of customers, number of employees, region, and revenue.

Market fluctuations can occur due to a variety of reasons, including true market movements, as well as changes in sample. Statistics derived from small sample sizes are particularly vulnerable to variations.

The table below shows the median values from the “All” data cut. The other percentiles and data cuts are available in the Excel file, where there are sufficient data to report.

			Base Salary	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Incentive %	Actual Total Cash	Total Cash Design
Job Code	Job Title	No. of Incumbents	P50	P50	P50	P50	P50	P50	P50
[redacted]									

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Job Code	Job Title	No. of Incumbents	Base Salary	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Incentive %	Actual Total Cash	Total Cash Design
			P50	P50	P50	P50	P50	P50	P50
[redacted]									

			Base Salary	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Incentive %	Actual Total Cash	Total Cash Design
Job Code	Job Title	No. of Incumbents	P50	P50	P50	P50	P50	P50	P50
[redacted]									

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Appendix A: Survey Methodology

To formulate the information in this report, Eckler collected data, conducted quality assurance, and aggregated information to publish statistics.

A survey package was distributed to each participant that collected jobs data for the survey benchmark roles, as well as information on the organization's profile, salary administration policies, and benefits policies. Participants matched their jobs to the benchmark job profiles and provided data for each position, where applicable. For each position where an organization submitted more than one match, each unique data point was reviewed to ensure that all matches were accurate and should all be included. If all are valid, then each unique data point was used for that organization.

Eckler reviewed all submitted survey packages and contacted participants to verify the data provided, as necessary. Space was provided for additional comments with respect to the reported data for the role as well to ensure participants were able to provide any important context to the data of special circumstances that would influence the pay for an incumbent or position. If any of the submitted matches to the benchmark roles were deemed incorrect or not representative of the market, those outlier data points were removed from the aggregated survey results.

Appendix B: Terms and Definitions

For collecting compensation data, Eckler provided definitions for various compensation elements which form both compensation design – the intended range of pay for a position, as well as actual compensation – what an incumbent is currently being paid in the role.

Job Match Information

Data Collection Field	Description
Job Title within your Organization	The title used in your organization for the position you have matched to the benchmark.
Quality of Match	Your assessment of the "size" (scope/complexity) of the job in your organization compared the benchmark job description provided. For some positions, indicators of scope are discussed in the description; for others it will be a matter of subjective assessment. + The position in your organization has greater scope and/or complexity than the benchmark. Typically, the job would be perceived as at least 15% larger. For people managers, greater scope may include a larger than "typical" number of staff and/or wider range of activities/functions being managed or supervised. At senior management & executive levels, greater scope may also include additional functions reporting into this position (e.g., IT and Customer Service reporting to the CFO would make the job "wider" than the CFO in the benchmark description). = The position in your organization is of similar scope and/or complexity as the benchmark. Typically, the job would be perceived as within +/- 15% of the benchmark. - The position in your organization has smaller scope and/or complexity than the benchmark. Typically, the job would be perceived as at least 15% smaller (i.e., less than 85% of the scope/complexity of the benchmark). For people managers, scope may include a smaller than "typical" number of staff and/or narrower range of activities/functions being managed or supervised. At senior management & executive levels, smaller scope may include functions that would normally be expected to report into this position reporting elsewhere.
Work Location	The postal code of the work location for this position.
Standard Hours of Work	The standard hours of work per week.
Number of Incumbents	The number of incumbents in the position you have matched.

Pay Grade	The pay grade / job grade / grade level used within your organization to designate the level of the job.

Design Compensation: Salary Range

Data Collection Field	Description
Minimum	The lowest salary/rate that the organization is prepared to pay for an incumbent in the position. May be the starting salary for inexperienced/non-qualified hire.
Job Rate / Control Point	The salary your organization is prepared to pay for competent performance by a fully trained incumbent. This is typically the midpoint of a salary range or the highest step of a step structure.
Maximum	The highest point in the salary range or the highest step of a step structure.

Design Compensation: Short Term (Annual Incentive)

Data Collection Field	Description
Eligible? (Y/N)	Is the position typically eligible to participate in a defined incentive plan designed to reward the individual for performance/results achieved during a period of one year or less?
Target (%)	If the position is eligible, record the target bonus rate for the position if the target bonus is communicated as a percentage of base salary. Target bonus is the level of award that an employee in this position would expect to receive if all corporate, team and individual performance goals are met.
Target ($)	If the position is eligible, record the target bonus rate for the position if the target bonus is communicated as a dollar amount. Target bonus is the level of award that an employee in this position would expect to receive if all corporate, team and individual performance goals are met.
Discretionary	If the position is eligible and the bonus plan is "discretionary". Discretionary plans have no target bonus rate and pay out at the end of the year at the discretion of executives / the board.

Actual Compensation

Data Collection Field	Description
Base Salary ($)	This is the annualized amount paid for work performed on a regular, ongoing basis. It does NOT include variable bonus or incentive payments, sales commissions, shift premiums, or overtime payments. Record on an annual, full time equivalent basis, as of April 1, 2024.
Bonus Paid ($)	Total of all short-term incentive awards paid to the incumbent(s) for performance/results over the previous year. If the incumbent joined the organization and/or became eligible for incentive pay during the year, and the actual bonus paid was on a pro-rated basis, please advise the annualized amount (before pro-rating).

Additional Information

Data Collection Field	Description
Comments / Additional Information	Record any information which you feel may assist in validating position matching or explaining special circumstances that influence pay.

Aggregated Statistics

Aggregated statistics are compiled by summing compensation elements; specifically, Eckler has prepared two aggregated statistics which provide a more holistic view of an incumbent's annual compensation.

- Total Cash Design: Salary Control Point or Job Rate + Incentive Target
- Actual Total Cash: Base Salary + Bonus Paid

Where a role is not provided with an incentive, Total Cash Design is equal to the Salary Control Point or Job Rate, and Actual Total Cash is equal to Base Salary.

Information surveyed is provided in aggregated form only to ensure that (1) data for individual organizations or incumbents is not disclosed and (2) to ensure a statistically relevant sample. Eckler requires a minimum number of observations to publish compensation statistics as follows:

Statistic	Definition	Minimum Number of Data Observations
P90	90th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 10% of the observations would fall above the 90th percentile and 90% would fall below.	12
P75	75th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 25% of the observations would fall above this value and 75% would fall below.	8
P50	50th percentile, also referred to as "median" If all observations were sorted and listed from highest/largest to lowest/smallest, 50% of the observations would fall above this value and 50% would fall below.	4
P25	25th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 75% of the observations would fall above this value and 25% would fall below.	8
P10	10th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 90% of the observations would fall above this value and 10% would fall below.	12
Average	Average The arithmetic mean of all values, calculated by adding up all the values and dividing by the number of observations.	3

Appendix C: Benchmark Job Models

[redacted]

Job Code	Job Title	Description
[redacted]		

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Job Code	Job Title	Description

[redacted]

[redacted]

Job Code	Job Title	Description
[redacted]		

[redacted]

Job Code	Job Title	Description
[redacted]		

Job Code	Job Title	Description
[redacted]		

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Job Code	Job Title	Description
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[redacted]		
		and material.

[redacted]

Job Code	Job Title	Description
[redacted]		

Job Code	Job Title	Description
[redacted]		

[redacted]

Job Code	Job Title	Description
[redacted]		

[redacted]

[redacted]

Job Code	Job Title	Description
[redacted]		

[redacted]

Job Code	Job Title	Description
[redacted]		

[redacted]

Job Code	Job Title	Description
[redacted]		

[redacted]

Job Code	Job Title	Description
[redacted]		

Job Code	Job Title	Description
[redacted]		

[redacted]

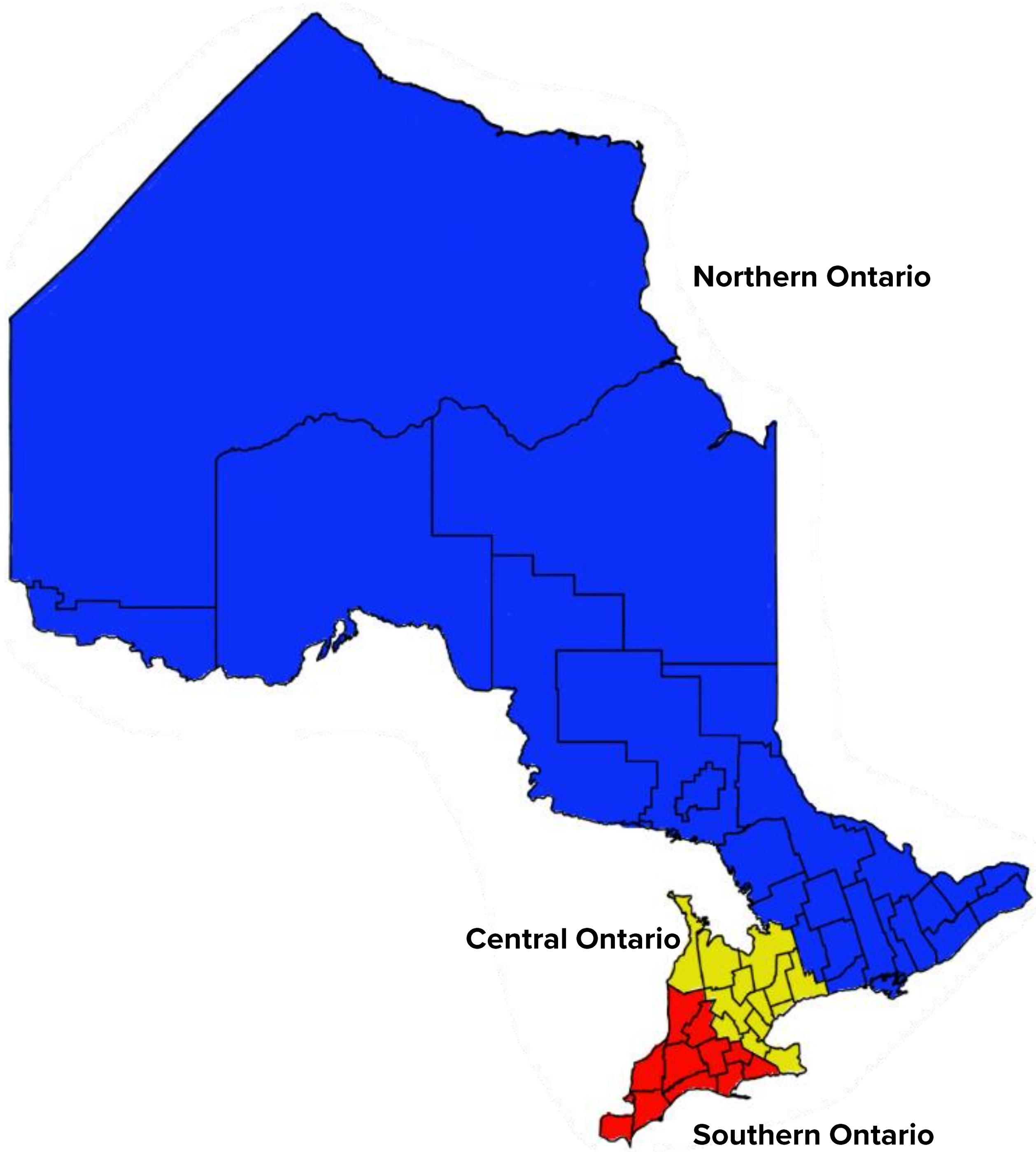
Job Code	Job Title	Description
[redacted]		

Job Code	Job Title	Description
[redacted]		

[redacted]

Job Code	Job Title	Description
[redacted]		

Appendix D: Region Map



Appendix E: About Eckler

Established in 1927, Eckler Ltd. is one of the longest-established and most respected consulting and actuarial practices in Canada. With over 350 employees, we are the largest independent benefits and pensions consulting firm in the country. Our head office is located in Toronto, with additional offices in Winnipeg, Vancouver, Montreal, Quebec City, Fredericton, and Halifax; and two offices in the Caribbean (Jamaica and Barbados).

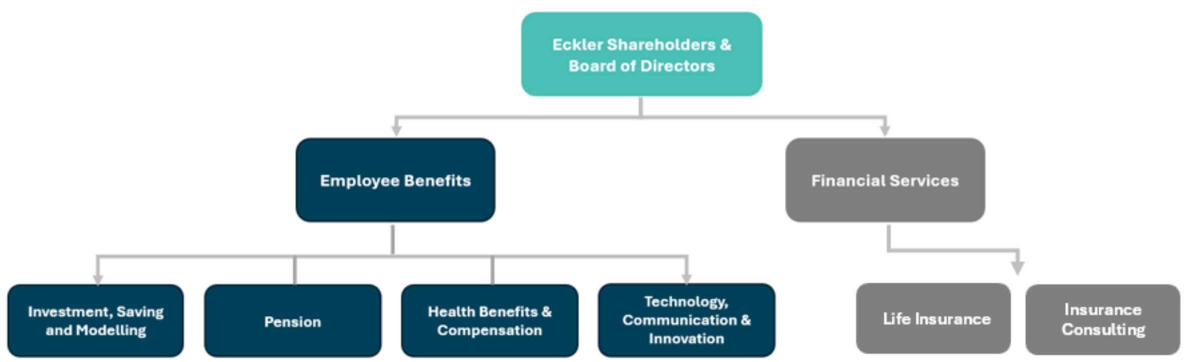
We have evolved from a strictly actuarial firm to a fully integrated consulting practice, offering a complete range of employee benefit services including group benefits consulting, investment consulting, asset/liability modelling, technology solutions, communication and change management consulting, defined contribution plan consulting, compensation consulting, as well as financial wellbeing education.

We are a privately-owned company with Principal Shareholders who are actively involved in our consulting practice. Each Shareholder owns an equal number of shares in the firm, which ensures a highly democratic and equitable distribution of authority and responsibility. This operational structure helps us to maintain a strong entrepreneurial culture while ensuring stability.

Eckler has a unique organizational structure that consists of two distinct business units:

- Employee benefits which provides consulting services primarily to sponsors of pension and benefits plans; and

- Financial services, which consults primarily to insurance and other financial services companies.



Eckler has also long been committed to creating a workplace where good people are welcome regardless of age, ancestry, colour, race, citizenship, ethnicity, place of origin, religion, creed, disability, family status, marital status, gender identity, gender expression, gender, and sexual orientation. We are committed to an inclusive work environment where everyone comes to work as their authentic self and feels welcomed, valued, and respected.

Eckler has been recognized by Waterstone Human Capital as one of Canada's Most Admired Corporate Cultures for multiple years. In addition, we are a proud member of the Canadian Council for Indigenous Business. Throughout our history, Eckler has always been guided by our democratic culture of trust and commitment to purpose.

Compensation Experience with Surveys

Understanding compensation, and specialized fields and industries can be very challenging. As a result, many sectors opt to conduct surveys that are specific to their own sector to obtain a clearer picture of the available talent in the market, and the cost of that talent. With high inflation, and a shrinking labour pools and emergence of hot skill in Canada for many professions, and a growing trend of needing to compete on a regional or even national level when work is remote/hybrid enabled, organizations are facing unprecedented challenges to attract, recruit, and retain talent.

We have supported many organizations in developing programs that recognize workforces being a significant asset and designing total rewards programs and communications plans that better position their total rewards strategically. In all our projects, our insights and program development are based upon reliable industry data which is a core deliverable of this project.

Our compensation team is located in Toronto, Vancouver, and Montreal, with several of the staff members having experience in running large-scale national surveys, as well as specific industry or profession surveys. In addition to our core consulting team, we also have communications and technology solutions that may be useful to leverage for communicating data insights and assisting in how the data should be published.

Need more information about Eckler or have a question about this report?

Contact compconsulting@eckler.ca and an Eckler colleague will respond to you.

Report Limitations

This report has been prepared by Eckler Ltd. ("Eckler") for the individuals and organizations who provided responses to The MEARIE Group 2025 Management Salary Survey of Ontario Local Distribution Companies, including the LDCs (the "Participants") and is meant for their exclusive use and must be used solely for the purpose of measuring and monitoring compensation and total rewards trends, challenges and risks (the "Purpose").

It must not be used for any other purpose, recited, referred to, published, quoted, replicated, reproduced, or modified (in whole or in part) except as required by law or regulatory obligation, without Eckler's prior written, express consent. The sole exception is that Participants may share this report for the Purpose internally within their organization ("Permitted Third Parties"), but without creating any duty or liability on the part of Eckler. Prior to Participants sharing this report with any Permitted Third Parties, such Permitted Third Parties must be informed that the report is confidential and must not be disclosed to any other party.

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The findings contained in this report may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties. Eckler accepts no responsibility for results based on future events. There may be changes in matters that affect the report subsequent to the date of this report. Neither the issue nor delivery of this report shall under any circumstance create any implication that the information contained herein is correct as of any time subsequent to the date hereof. No obligation is assumed to revise this report to reflect changes, events, or conditions, which occur subsequent to the date hereof.

You will not bring any claim or lawsuit, under any theory of law, or lay any professional complaint, against Eckler, or any of their employees related in any way to the report and you hereby waive and release Eckler, and their directors, officers and employees from any claims or losses against Eckler in connection with the report. You understand and agree that Eckler (a) makes no representation or warranty hereunder as to the accuracy or completeness of the information in the report; and (b) shall have no liability hereunder, including for any loss or damage, relating to or resulting from the use of the report or any errors, omissions or inaccuracies therefrom.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 1.0-VECC-1

Reference:
Exhibit 1, page 48

a) Does Entegrus Transmission Inc. continue to operate and if so does it have any transactions with the utility EPI?

RESPONSE:

a) Entegrus Transmission Inc. remains an active corporate entity for financial reporting and tax filing purposes, but no longer conducts operations and has no transactions with EPI.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 1.0-VECC-2

Reference:
Exhibit 1, pages 57-

a) What was the total cost of the Innovative Research Group customer engagement, including the supplemental tariff survey?

b) Please provide the cost of the Concentrix Transactional Customer survey and explain how often this survey is undertaken.

RESPONSE:

a) The Innovative Research Group application-specific customer engagement surveys totaled $100,125.

b) The Concentrix Transactional Customer survey is completed annually and the cost is $45,795, which includes the provider maintaining an online portal, through which EPI monitors transactional survey results in near real time throughout the year.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 1.0-VECC-3

Reference:
Exhibit 1, page 64

“As of the date of filing this Application, no letters of comment have been received.

EPI will file all responses to matters raised in letters of comment filed with the OEB during the course of the proceeding in this Exhibit 1, in accordance with Section 2.4.9 of the Filing Requirements.”

a) Please provided the noted summaries of letters of comment and how EPI is addressing the stated concerns.

RESPONSE:

a) Please see the response at 1-Staff-2.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 1.0-VECC-4

Reference:
Exhibit 1, page 67

"EPI engages a third-party service provider to conduct ongoing First Contact Resolution 1 ("FCR") surveys. FCR traditionally represents a percentage of instances where a customer's need is addressed at the time of their first point of contact on the matter."

a) Does the FCR service provider produce reports for EPI? If yes how often are these reports provided?

b) Is this the report, referred to in Attachment 1-F as the "Concentrix Transactional Customer survey? If not, please provide the most recent transactional survey provided to EPI.

RESPONSE:

a) Yes, please refer to the response at 1-VECC-2 part b). The FCR service provider (Concentrix) produces two annual reports for EPI, a Top-Down Customer Survey (CSAT) and a Transactional Customer Survey (FCR), the most recent versions of which are provided in Exhibit 1 as Attachments 1-E and 1-F.

b) Confirmed. The Concentrix Transactional Customer Survey (Attachment 1-F) is the most recent transactional survey report provided to EPI.

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