Exhibit 1: Application and Administrative Documents

TABLE OF CONTENTS

1 Application Overview and Administrative Documents 1
1.1 Application 7
1.2 Application Table of Contents 9
1.3 EPI Business Plan 11
1.3.1 EPI's Business Plan and Objectives 11
1.4 Application Summary 15
1.4.1 Revenue Requirement 15
1.4.2 Load Forecast Summary 17
1.4.3 Rate Base and Distribution System Plan 18
1.4.4 Capital Expenditures 23
1.4.5 Operations, Maintenance and Administration Expense 26
1.4.6 Cost of Capital 29
1.4.7 Cost Allocation and Rate Design 30
1.4.8 Deferral and Variance Accounts 34
1.4.9 Bill Impacts 34
1.5 Administration 36
1.5.1 Certification of Evidence 36
1.5.2 Board of Directors Certification 36
1.5.3 Filing Requirements Checklist 36
1.5.4 Primary Contact Information 36
1.5.5 Legal Representation 37
1.5.6 Internet Address and Social Media 38
1.5.7 Statement of Publication 38
1.5.8 Materiality Threshold 38
1.5.9 Form of Hearing 40
1.5.10 Proposed Effective Date of Rate Order 40
1.5.11 Changes to Methodologies Used in Previous Applications 40

1.5.12 OEB Directions from Previous Decisions and/or Orders 40
1.5.13 Conditions of Service 41
1.5.14 Corporate and Utility Organizational Structure 42
1.5.15 Corporate Governance 45
1.5.16 Approvals Requested 47
1.6 Distribution System Overview 49
1.6.1 The Evolution of Entegrus 49
1.6.2 Overview of Service Area 51
1.6.3 Identification of Embedded or Host Utilities 53
1.7 Customer Engagement 55
1.7.1 Overview 55
1.7.2 Ongoing Customer Engagement 55
1.7.3 Application Specific Customer Engagement 57
1.7.4 Customer Engagement with Customers affected by Cost of Service Proposals 62
1.7.5 Consultations with other parties 62
1.7.6 Letters of Comment 64
1.8 Performance Measurement 65
1.8.1 Scorecard and Performance Improvement Targets 65
1.8.2 PEG Model 74
1.8.3 OEB-Approved IRM Increases and Assigned Cohort 75
1.8.4 Activity and Performance-Based Benchmarking (“APB”) 76
1.9 Facilitating Innovation 82
1.9.1 Transformational Innovation 82
1.9.2 Process and Operational Improvement 85
1.10 Financial Information 86
1.10.1 Audited Financial Statements 86
1.10.2 Reconciliation of Financial Statements 86
1.10.3 Annual Report and Management Discussion and Analysis 86
1.10.4 Rating Agency Report 87

1.10.5 Prospectuses or Information Circulars ... 87
1.10.6 Changes in Tax Status ... 87
1.10.7 Accounting Orders ... 87
1.10.8 Departures from the Uniform System of Accounts ("USoA") ... 87
1.10.9 Accounting Standard Used ... 88
1.10.10 Non-Utility Business Accounting ... 88
1.11 Distributor Consolidation ... 89
1.11.1 Overview ... 89
1.11.2 Incentives that Formed Part of Acquisition ... 91
1.11.3 Commitments Made to Shareholders ... 91
1.11.4 Projected And Realized Savings as a Result of Consolidation Compared to MAADs Application 91
1.11.5 Efficacy of Rate Plan ... 94
1.11.6 ICM Applications ... 95
1.12 Impacts of COVID-19 Pandemic ... 95
1.12.1 OM&A and Capital Impacts ... 96
1.12.2 Customer Support and Recovery Status ... 96
1.12.3 Load Forecast Impacts ... 97

TABLES

Table 1-1: 2016 OEB Approved Proxy vs. 2026 Test Year 15
Table 1-2: Load Forecast 18
Table 1-3: Summary of Rate Base 19
Table 1-4: Proposed Capital Investments 23
Table 1-5: 2016 OEB Approved Proxy vs. 2026 Test Year Capital Expenditures 24
Table 1-6: Changes in OM&A Between 2016 OEB Approved Proxy and 2026 Test Year 27
Table 1-7: Capital Structure and Cost of Capital 29
Table 1-8: Proposed Revenue to Cost Ratios 31
Table 1-9: Comparison of Current and Proposed Distribution Rates 33
Table 1-10: 2026 Proposed Bill Impacts Total Bill 35
Table 1-11: 2026 Proposed Bill Impacts – Breakdown by Subtotal 35
Table 1-12: EPI's Materiality Threshold for the 2026 Test Year 39
Table 1-13: EPI Distribution System Characteristics 53
Table 1-14: EPI Regional Planning Areas and Statuses 63
Table 1-15: Historical ROE 74
Table 1-16: Historical Efficiency Assessment Performance 75
Table 1-17: EPI Forecast Efficiency Assessment Performance 75
Table 1-18: OEB Approved IRM Increases 76
Table 1-19: Billing O&M Cost Per Customer 76
Table 1-20: Metering O&M Cost Per Customer 77
Table 1-21: Vegetation Management O&M Cost Per Pole 77
Table 1-22: Lines O&M Cost Per Circuit KM of Primary Line 78
Table 1-23: Stations O&M Cost Per Total MVA 79
Table 1-24: Poles, Towers, Fixtures O&M Cost ($) Per Pole 79
Table 1-25: Stations CAPEX Cost Per Total MVA 80
Table 1-26: Poles, Towers and Fixtures CAPEX Cost Per Pole 80
Table 1-27: Line Transformer CAPEX Cost Per Transformer 81
Table 1-28: Meters CAPEX Cost Per Customer 81
Table 1-29: Actual 2024 and Forecast 2025-2026 APB Results 82
Table 1-30: EB-2017-0212 MAADs Projected Net Savings From EPI/STEI Merger 92
Table 1-31: EB-2017-0212 MAADs Componentization of Projected Cost Savings from EPI/STEI Merger – Interrogatory Response 93
Table 1-32: Realized Net Savings from EPI/STEI Merger 93
Table 1-33: Componentization of Net Savings from EPI/STEI Merger 94

List of Attachments

1-A. Certification of Evidence

1-B. EPI 2026-2030 Business Plan

1-C. Corporate Governance Policies & Documents

1-D. The 2024 EPI Scorecard

1-E. Concentrix Top-Down Customer Survey

1-F. Concentrix Transactional Customer Survey

1-G. Innovative Research Group Customer Consultation Reports

1-H. Audited Financial Statements for 2024

1-I. Reconciliation of Audited Financial Statements to RRR Trial Balances

1-J. Rating Agency Report

1.1 Application

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15, 3 Schedule B, as amended (the "OEB Act");

AND IN THE MATTER OF an Application by Entegrus Powerlines Inc. under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2026.

(this "Application")

Applicant's Name: Entegrus Powerlines Inc.
(the "Applicant" or "EPI").

The Applicant is a corporation incorporated pursuant to the Business Corporations Act (Ontario) with its head office at 320 Queen Street, P.O. Box 70, Chatham, Ontario, N7M 5K2. The Applicant carries on the business of distributing electricity within the 17 communities in Southwestern Ontario detailed in Section 1.6.2.

The period for this Application covers 11 years with (i) nine years of historical information for the 2016-2024 period, (ii) 2025 Bridge Year, and (iii) a one-year forward test period – the 2026 Test Year. The Distribution System Plan ("DSP") covers 10 years, (i) four years of historical information for the 2021-2025 period, (ii) 2025 Bridge Year, and (iii) a five-year forecast period beginning with the 2026 Test Year and ending in 2030.

EPI has prepared this Application in accordance with the following:

- The OEB's Renewed Regulatory Framework for Electricity Distributors as detailed in the Report of the Board dated October 18, 2012 (the "RRFE").
- The OEB's Handbook for Utility Rate Applications issued October 13, 2016.

- Chapters 2 and 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications – 2025 Edition for 2026 Rate Applications (the "Filing Requirements"), issued December 9, 2024 and corrected May 7, 2025, unless otherwise stated in the Application.
- The Applicant acknowledges that the OEB will publish an update to the Cost of Capital Parameters and that these matters will affect the Revenue Requirement that the Applicant has requested in this Application.
- EPI has not deviated from these filing requirements and has filed a copy of the completed 2026 Cost Of Service ("COS") Checklist (standalone excel file EPI_2026_COS_Checklist_20250829).

1.2 Application Table of Contents

EPI provides a Table of Contents listing the major sections of its Application below. A separate PDF file is provided for each Exhibit, and each Exhibit contains a separate table of contents outlining the key sections and subsections within the Exhibit.

EPI's Application consists of the following Exhibits and live Excel models supporting the evidence presented in EPI's Application.

- Exhibit 1: Application Overview and Administrative Documents
- Exhibit 2: Rate Base and Capital
- Exhibit 3: Customer and Load Forecast
- Exhibit 4: Operating Expenses
- Exhibit 5: Cost of Capital
- Exhibit 6: Revenue Requirement
- Exhibit 7: Cost Allocation
- Exhibit 8: Rate Design
- Exhibit 9: Deferral and Variance Accounts

- 01. EPI_2024_Benchmarking_Spreadsheet_Forecast_Model_20250829
- 02. EPI_2026_Filing_Requirements_Chapter2_Appendices_1.0_20250829
- 03. EPI_2026_CoS_Load_Forecast_Model_20250829
- 04. EPI_2026_Rev_Reqt_Workform_1.0_20250829
- 05. EPI_2026_Test_Year_Income_Tax_PILs_1.0_20250829
- 06. EPI_Utilis_LoadProfile_Template_20250829
- 07. EPI_2026_Cost_Allocation_Model_1.0_20250829
- 08. EPI_2026_RTSR_Workform_1.0_EV_20250829
- 09. EPI_Main_2026_Tariff_Schedule_and_Bill_Impact_Model_20250829
- 10. EPI_STT_2026_Tariff_Schedule_and_Bill_Impact_Model_20250829

- 11. EPI_2026_DVA_Continuity_Schedule_CoS_1.0_20250829
- 12. EPI_Group 2_DVA Continuity Schedule_20250829
- 13. EPI_2026_Commodity_Accounts_Analysis_Workform_1.0_20250829
- 14. EPI_2026_Accelerated CCA Deferral Support_20250829
- 15. EPI_2026_COS_Checklist_20250829

1.3 EPI BUSINESS PLAN

1.3.1 EPI'S BUSINESS PLAN AND OBJECTIVES

In accordance with the OEB's Handbook for Utility Rate Applications, EPI has prepared a formal Business Plan that outlines EPI's overall strategy and goals. EPI's Business Plan is a roadmap for continuing success, delivering on its mission and assisting EPI**'S** progress toward its vision. The Business Plan was approved by EPI's Board of Directors on August 6, 2025, and is included in this Exhibit as Attachment 1-B.

Key EPI objectives that informed this Application are as follows:

- Maintain a strong internal and public health and safety focus by upholding EPI's Infrastructure Health and Safety Association ("IHSA") Certification in Ontario ("COR") accreditation and continuing to advance a proactive safety culture
- Renew aging infrastructure through coordinated capital investments that prioritize degraded and at-risk assets, while modernizing the system through paced voltage conversions and lifecycle replacement of aging smart meters
- Support customer growth and ensure prompt system access through timely connections, targeted upgrades and planning aligned with ongoing residential and industrial development across EPI's service area
- Advance system modernization and reliability by deploying operational technologies such as smart switches and sectionalizers, while supporting Distributed Energy Resources ("DERs") and non-wires alternatives ("NWAs"), including assessment and coordination with customers and third parties
- Continue the digitization of operations and expand data analytics to enable more data-informed planning and decision-making, supported by sustained investments in cybersecurity to protect systems and meet compliance obligations

- Prepare for, monitor and respond to changing customer electricity needs, such as adoption of electric vehicles and heat pumps, by planning and building the distribution system for reasonable forecasted load growth and replacing at-risk transformers to support load intensification
- Support these evolving requirements through a modernized and expanded workforce and investing in training and succession planning
- Enhance the customer experience through improved digital self-service tools, website enhancements, and expanded communication channels such as social media, live chat, and a new mobile application
- Mitigate cost pressures from inflation and supply chain disruption through joint procurement strategies, adaptive project scheduling, and operational flexibility to maintain service reliability and investment continuity

Notwithstanding these objectives, EPI's total costs are forecasted to remain significantly below those predicted by the OEB consultant's econometric model. EPI forecasts sustaining its placement in the first Total Cost Benchmarking efficiency cohort in the 2026 Test Year (see Section 1.8.2), enabling EPI to balance the modernization of its operations and distribution system with the delivery of affordable distribution rates (see Section 1.4.9).

EPI's Mission, Vision and Core Values are detailed in the Business Plan and are summarized below.

MISSION

"To provide safe, reliable delivery of electricity and related services, in an environmentally and fiscally responsible manner. To provide exceptional service to our customers, support to the communities we serve and rewarding growth opportunities for our employees."

VISION

"To be an industry leader in all we do."

CORE VALUES

EPI's core values are as follows:

SAFETY	***"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
INSPIRED & EMPOWERED PEOPLE	***"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
CUSTOMER & COMMUNITY FOCUS	***"Exceeding the needs 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
OPERATIONAL EXCELLENCE	***"Achieving operational excellence by always striving for continuous improvement."*** • Efficient • Effective • Continuous improvement • Intelligent investment

SUSTAINABLE GROWTH	***"Delivering sustainable growth for our stakeholders through wise investments."*** • Investing wisely • Maximizing shareholder return • Serving community/communities

1.4 Application Summary

As described below in Section 1.6.1, on April 1, 2018 Legacy EPI merged with St. Thomas Energy Inc. ("STEI"), with the amalgamated utility continuing as EPI. Accordingly, throughout this Application, EPI uses the concept of 2016 OEB Approved Proxy figures, as a stand-in comparator for the utility's most recent OEB-approved COS application. This concept recognizes that EPI's previous COS application (EB-2015-0061) was filed for 2016 rates, while the former STEI's previous COS application (EB-2014-0113) was for 2015 rates.

As a result, EPI's 2016 OEB Approved Proxy figures are a means to reflect the figures of both predecessor utilities. The 2016 OEB Approved Proxy figures were calculated as the aggregate of the following components:

- The legacy EPI 2016 OEB Approved amounts as approved in EB-2015-0061; and,
- The STEI 2015 OEB Approved amounts, as approved in EB-2014-0113, inflated to 2016 amounts by STEI's 2016 OEB Approved IRM net price cap index adjustment of 1.8%.

Further details on the calculation of 2016 OEB Approved Proxy figures are provided in the various Exhibits of this Application, where applicable. The 2016 OEB Approved Proxy best reflects the amounts previously approved by the OEB for each of EPI and STEI. Similarly, to provide a comparable basis for the Historical Period, 2016 Actuals and 2017 Actuals are presented on a combined basis (as if the merger had occurred January 1, 2016) unless otherwise noted.

1.4.1 Revenue Requirement

EPI is requesting approval of a service revenue requirement of $42,018,987; an increase of $15,361,816 over a 10-year period, equivalent to a 57.6% increase or a compound annual growth rate of 4.7%, relative to the 2016 OEB Approved Proxy, as presented below in Table 1-1.

Table 1-1: 2016 OEB Approved Proxy vs. 2026 Test Year

Line No.	Description	2016 OEB Approved Proxy	2026 Test Year	Variance
		A	B	C = B - A
1	**Revenue Requirement:**			
2	OM&A	$13,962,859	$20,819,676	$6,856,817
3	Depreciation	$4,846,465	$8,054,879	$3,208,414
4	Property Tax	$347,100	$313,730	-$33,370
5	Income Tax	$141,332	$745,248	$603,916
6	LEAP	$32,173	$308,190	$276,017
7	Return on Rate Base	$7,327,242	$11,777,263	$4,450,021
8	**Total**	**$26,657,171**	**$42,018,987**	**$15,361,816**
9	**Rate Base**			
10	Rate Base	$116,219,190	$190,347,116	$74,127,926

The main drivers of this increase are described as follows:

- **Operating Maintenance & Administration ("OM&A") Expense Increase:** EPI's OM&A component has increased by approximately $6.9M, as explained in Exhibit 4, Section 4.2 and Exhibit 4, Table 4-7. This increase reflects higher operating costs, primarily related to salaries, wages and benefits (driven in part by workforce modernization), inflationary pressures on non-labour items, enhanced spending on cybersecurity and licensing, and increased bad debt expense. These cost increases are partially offset by merger-related synergies.

- **Depreciation Increase:** EPI's depreciation component has increased by approximately $3.2M. This increase in depreciation is driven by a 64% increase in rate base from 2016 to 2026. For additional details please see Exhibit 2, Section 2.3.4.

- **Payments-in-Lieu of Taxes ("PILs") Increase:** The increase in the PILS component of approximately $604k is attributable to an increase in Return on Rate Base, which is discussed in Exhibit 6, Section 6.3.

- **Low Income Energy Assistance Program ("LEAP") Increase:** The increase in LEAP costs of approximately $276k is driven by the OEB's EB-2023-0135 Decision and Order which announced changes to the LEAP Emergency Financial Assistance ("EFA"). The Decision stated that no eligible LEAP EFA applicant should be denied the emergency grant due to lack of funding. The changes resulted in EPI assisting an increased number of vulnerable customers with LEAP funding at a higher dollar amount.

- **Return on Rate Base Increase:** The increase in Return on Rate Base of approximately $4.5M is driven by an increase in Rate Base of $74.1M. The average Net Book Value of EPI's assets increased by approximately $75.1M between the 2016 OEB Approved Proxy and the 2026 Test Year, offset by a $986k decrease in Working Capital Allowance ("WCA") between the 2016 OEB Approved Proxy and the 2026 Test Year, as shown in Exhibit 2, Table 2-4. Please also refer to the calculation of the weighted average cost of capital in Table 1-7.

1.4.2 Load Forecast Summary

As outlined in Exhibit 3, EPI used the same multi-variate regression methodology approved by the OEB in its 2016 COS Application (EB-2015-0061), and many other COS applications approved by the OEB over the past two decades, in forecasting load and customers for the 2026 Test Year. The regression analysis includes actual data to the end of 2024 and relies on statistically valid independent variables to produce an equation predicting weather normalized power purchases in 2026. This forecast was prepared at a combined level representing both of EPI's current rate zones (Legacy Entegrus and St. Thomas).

Given the international trade developments and tariff policy uncertainty emerging in 2025, EPI sent a short supplemental survey to automotive and manufacturing customers in June/July 2025. While respondents acknowledged trade-related risks, most anticipated their load would remain stable or increase. Based on this feedback, EPI applied a moderated 4% decrease to the Manufacturing Sales variable by 2026 due to Canada-U.S. trade and tariffs, rather than the 8% decline in Manufacturing GDP by 2026 projected by the Financial Accountability Office of Ontario report. See Section 1.7.3 for more details.

Table 1-2 below showcases the load and customer/connection forecast for 2026. For in-depth insights regarding the load forecast, please refer to Exhibit 3.

TABLE 1-2: LOAD FORECAST

	2016 OEB-approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Bridge Weather Normal	2026 Test Weather Normal
Purchases													
Actual kWh Purchases		1,231,015,857	1,210,096,647	1,188,982,964	1,250,101,306	1,224,321,310	1,208,016,677	1,247,990,626	1,291,380,740	1,271,943,859	1,308,625,064		
Predicted kWh Purchases		1,199,063,316	1,234,463,415	1,213,060,463	1,265,520,593	1,234,831,313	1,193,727,393	1,245,247,088	1,293,544,336	1,274,798,029	1,278,219,103	1,282,056,224	1,275,076,684
% Difference between actual and predicted purchases		-2.6%	2.0%	2.0%	1.2%	0.9%	-1.2%	-0.2%	0.2%	0.2%	-2.3%		
Loss Factor		1.07	1.04	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Total Billed	1,227,795,880	1,148,834,613	1,164,182,009	1,150,940,106	1,205,049,800	1,172,895,489	1,159,425,254	1,199,960,377	1,243,292,925	1,223,014,611	1,258,616,415	1,229,717,869	1,223,023,260
Billing Determinants													
Residential													
Customers	51,380	50,512	51,681	52,149	52,686	53,245	53,933	54,771	55,652	56,302	56,797	57,542	58,297
kWh	401,024,138	396,832,649	405,183,155	387,000,725	425,242,692	411,936,659	439,168,361	447,806,289	447,775,679	429,855,844	452,835,509	444,972,213	448,377,107
General Service < 50 kW													
Customers	5,589	5,527	5,638	5,655	5,686	5,694	5,704	5,732	5,799	5,860	5,889	5,931	5,973
kWh	141,798,443	152,529,020	152,498,211	152,138,066	158,043,644	153,655,138	143,543,988	153,599,300	158,958,811	159,307,883	165,653,054	161,805,674	162,071,320
General Service > 50 to 4999 kW													
Customers	665	598	584	563	549	557	560	542	521	512	509	499	491
kWh	607,596,812	526,568,936	527,388,658	535,305,320	535,709,795	517,080,387	492,213,122	509,952,256	527,626,633	523,144,015	525,118,764	507,933,868	497,570,107
kW	1,603,369	1,406,752	1,384,771	1,472,726	1,449,719	1,406,359	1,388,269	1,369,362	1,416,160	1,409,639	1,416,608	1,374,287	1,346,247
Large Use													
Customers	2	2	2	2	2	2	2	2	3	4	4	4	4
kWh	66,098,244	60,621,606	68,820,301	68,876,378	78,736,784	83,222,289	77,427,944	81,637,911	101,920,233	103,677,541	108,051,127	108,051,127	108,051,127
kW	182,047	147,251	227,701	235,754	248,846	192,286	180,186	189,299	228,227	239,895	256,332	249,434	249,434
Unmetered Scattered Load													
Connections	335	251	258	246	228	228	226	224	224	224	225	222	220
kWh	1,288,075	1,247,803	1,254,321	1,348,221	1,344,468	1,276,935	1,272,419	1,247,052	1,247,677	1,250,514	1,238,523	1,223,837	1,209,325
Sentinel Lighting													
Connections	584	522	520	451	382	393	376	342	323	308	304	286	270
kWh	419,179	452,830	434,815	423,109	420,751	423,572	461,598	357,348	378,834	365,715	358,166	337,320	317,687
kW	1,284	1,257	1,211	1,177	1,039	1,060	1,023	860	913	876	855	848	798
Street Lighting													
Connections	17,902	17,883	17,923	17,947	18,034	18,075	18,138	18,335	18,585	18,793	18,885	18,999	19,115
kWh	9,570,989	10,581,768	8,602,548	5,848,287	5,551,665	5,300,509	5,337,821	5,360,221	5,385,057	5,413,099	5,361,272	5,393,831	5,426,587
kW	27,987	30,672	25,106	16,203	15,561	15,393	15,438	15,533	15,621	15,696	15,533	15,525	15,619
Total													
Customer/Connections	76,457	75,293	76,604	77,012	77,566	78,193	78,938	79,946	81,106	82,003	82,612	83,484	84,368
kWh	1,227,795,880	1,148,834,613	1,164,182,009	1,150,940,106	1,205,049,800	1,172,895,489	1,159,425,254	1,199,960,377	1,243,292,925	1,223,014,611	1,258,616,415	1,229,717,869	1,223,023,260
kW	1,814,687	1,585,932	1,638,788	1,725,860	1,715,165	1,615,098	1,584,916	1,575,053	1,660,921	1,666,106	1,689,328	1,640,094	1,612,098

1.4.3 RATE BASE AND DISTRIBUTION SYSTEM PLAN

RATE BASE

Table 1-3 below summarizes the 2026 Test Year Rate Base relative to the 2016 OEB Approved Proxy. EPI is forecasting a 2026 Test Year Rate Base of $190.3M which represents a $74.1 million or 64% increase over the 2016 OEB Approved Proxy Rate Base of $116.2M. This growth is primarily driven by an increase in average net book value of capital assets, resulting from sustained investment in System Renewal, System Access and modernization and infrastructure upgrades across EPI's 17 communities.

TABLE 1-3: SUMMARY OF RATE BASE

Line No.	Description	2016 OEB Approved Proxy	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Bridge	2026 Test
1	Gross Fixed Assets	$ 199,651,299	$ 120,117,294	$ 130,843,341	$ 135,988,350	$ 146,387,815	$ 159,447,712	$ 173,276,411	$ 187,240,684	$ 201,862,877	$ 218,741,773	$ 241,315,290	$ 259,868,290
2	Accumulated Depreciation	$ (94,666,851)	$ (14,955,525)	$ (20,626,557)	$ (21,670,137)	$ (27,377,311)	$ (33,700,150)	$ (40,367,345)	$ (47,118,870)	$ (54,072,335)	$ (60,902,185)	$ (68,603,327)	$ (76,705,179)
3	Net Book Value	$ 104,984,448	$ 105,161,769	$ 110,216,784	$ 114,318,213	$ 119,010,504	$ 125,747,562	$ 132,909,066	$ 140,121,814	$ 147,790,542	$ 157,839,588	$ 172,711,963	$ 183,163,111
4	**Average Net Book Value**	**$ 102,823,542**	**$ 103,898,863**	**$ 107,689,276**	**$ 112,267,498**	**$ 116,664,358**	**$ 122,379,033**	**$ 129,328,314**	**$ 136,515,440**	**$ 143,956,178**	**$ 152,815,065**	**$ 165,275,775**	**$ 177,937,537**
5	Total Working Capital	$ 167,493,197	$ 172,591,306	$ 159,367,258	$ 154,210,891	$ 159,574,112	$ 178,040,122	$ 160,647,517	$ 163,593,445	$ 161,406,725	$ 180,118,371	$ 165,850,747	$ 165,461,051
6	Working Capital Allow. Factor	8.0%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
7	**Working Capital Allowance**	**$ 13,395,647**	**$ 12,944,348**	**$ 11,952,544**	**$ 11,565,817**	**$ 11,968,058**	**$ 13,353,009**	**$ 12,048,564**	**$ 12,269,508**	**$ 12,105,504**	**$ 13,508,878**	**$ 12,438,806**	**$ 12,409,579**
8	**Rate Base**	**$ 116,219,190**	**$ 116,843,211**	**$ 119,641,821**	**$ 123,833,315**	**$ 128,632,417**	**$ 135,732,042**	**$ 141,376,878**	**$ 148,784,948**	**$ 156,061,682**	**$ 166,323,943**	**$ 177,714,581**	**$ 190,347,116**

The EPI service territory is a product of multiple acquisitions and amalgamations of previously independent distributors dating back to the mid-2000s. Much of the foundational system expansion in the EPI communities occurred between 1950 and 1980. EPI's Asset Condition Assessment ("ACA") confirmed that a significant portion of its distribution system assets are approaching or have reached end-of-life. As described below, ACA input is essential to the ongoing execution of EPI's long-term asset management and DSP, ensuring that capital programs are both risk-prioritized and forward-looking.

In addition to supporting long-term system integrity, these investments enhance resiliency to adverse weather events, which have increased in frequency and intensity across EPI's service area (see Exhibit 2, Attachment 2-C (DSP), Section 3.3.2.4). Reinforced infrastructure and distribution automation provide faster restoration and greater flexibility in responding to storm-related outages.

EPI also continues to assess and plan for the demand impacts associated with Ontario's housing policy direction, including legislation such as the More Homes Built Faster Act, 2022, which focuses on acceleration of residential development. In parallel, EPI's focus on asset renewal and graduated move to larger transformation capacity for residential customers incorporates evolving electricity usage.

DISTRIBUTION SYSTEM PLAN

EPI's 2026 DSP (refer to Exhibit 2, Attachment 2-C) was developed in alignment with the OEB's RRFE outcomes of Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance, which are integrated with EPI's core values.

The DSP builds on lessons learned since EPI's 2016 DSP and reflects current operational realities, customer needs and preferences and external drivers. Specific objectives of the 2026 DSP include:

- Safety: maintain a strong focus on public and employee safety through continuous improvement and adherence to industry best practices;
- Sustainability: ensure system reliability and availability through targeted investments while balancing affordability for customers;
- Customer Evolution: respond to evolving customer needs and industry trends, including technological transformation and government policy objectives;
- Efficiency and Innovation: optimize the distribution system through proactive and cost-effective investment strategies that leverage data-driven decision-making and modernized infrastructure.

To help realize these objectives, EPI has outlined the following strategies as part of its 2026 DSP:

- Investment in reliability and availability: Prioritize capital investments that maintain system reliability and availability while managing rate impacts.
- Support for evolving customer energy needs and load intensification: modify residential engineering standards and planning practices to facilitate increased customer access to electricity and support urban intensification aligned with provincial housing objectives.
- Integration of DERs and NWAs: enhance the distribution system's capacity to integrate DERs and evaluate NWAs, aligning with industry transformation and policy objectives.
- Environmentally responsible practices: integrate environmentally responsible planning and design principles to minimize the ecological impact of EPI's asset base and the impact of climate change.
- Avoidance of 4 kV substation rebuilds: continue targeted voltage conversion programs to phase out 4 kV substations, avoiding major rebuilds and improving system efficiency and capacity.

- Proactive replacement of high importance aged assets: focus on the proactive replacement of high importance aged and deteriorated assets with modern, efficient infrastructure to maintain system reliability and performance.
- Adoption of innovative technologies: implement modern tools and innovative technologies to support effective asset management, system visibility, and operational performance.
- Data-driven decision-making: utilize data-driven modelling approaches to prioritize and optimize capital investments, ensuring prudent and effective use of resources.

Key Changes Since Last DSP

Since the 2021 DSP, the following learnings and improvements have been incorporated:

- ACA and Data Collection Enhancements: EPI has improved the volume and quality of asset condition data through expanded inspection programs and refined assessment methodologies. Annual resistograph-based testing of up to 2,000 poles, combined with ACA methodology improvements introduced in 2024, now supports multi-parameter health indexing for key asset classes.
- Engineering and Analytics Capability Expansion: To support modernization and respond to increasing system complexity, EPI has strategically expanded its internal capacity through new Engineers-in-Training, Engineering Technologists, and, in 2025, a dedicated Data Scientist. These roles support load flow studies, DER integration, project execution, and asset risk analysis. The Data Scientist role enables predictive modelling and the development of AI tools, an example of which is a tool that identifies transformers most at risk of overload. Together, these resources enhance asset planning, outage mitigation, and system performance while ensuring engineering and operational consistency.
- Digital Mapping and Control Room Modernization: EPI has modernized its GIS and Control Room systems to enhance real-time visibility, operational safety, and resiliency. A 2024 GIS upgrade included a new data model, mobile/web access, and full software replacement. The digitized Control

Room now benefits from improved visualization, enhanced data integrity, and business continuity protections in case of physical disruptions or control room failure scenarios.

EPI's investment plans are the outcome of its business planning efforts, enhanced asset management and capital expenditure planning process, customer engagement and coordination with third parties. The 2024 ACA was a key input. EPI's consultant METSCO delineated 15 categories and subcategories of assets, covering the entire EPI-installed asset base. The ACA showed that key asset classes were in "Very Poor" condition. Assets identified as "Very Poor" in the ACA have reached the end of their useful life and are at an elevated risk of failure. This includes the following asset category percentages identified as "Very Poor": Station Switches (100%), Wood Poles (9%), Steel Poles (10%), Concrete Poles (65%), Underground Primary Cables (22%), and Overhead Switches (10%). This shows a continued need for reinvestment to maintain system integrity, and in the case of Station Switches, reflects the need to document additional asset condition data. In its report conclusion, METSCO identified a "significant need for investment into EPI's systems" and assessed that such investments will "provide substantial benefits that will empower EPI to better serve its current customers and accommodate growth". This confirms the need for reinvestment to sustain system integrity and maintain customer reliability.

Projects and programs are categorized based on the four categories outlined in the Filing Requirements and are prioritized based on system needs and customer expectations:

- System Access investments are modifications (including asset relocation) to the distribution system that EPI is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.
- System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of EPI's distribution system to provide customers with electricity services.
- System Service investments are modifications to EPI's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.

- General Plant investments are modifications, replacements, or additions to EPI's assets that are not part of its distribution system including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities.

The DSP and EPI's Capital Expenditure Plan seeks to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of an asset is minimized. As will be demonstrated in the DSP as well as the remainder of this summary, the proposed levels of capital investment, for each category and in total, are relatively consistent from the 2026 Test Year through 2030. As shown in Table 1-4 below, this is reflective of EPI's belief that over the forecast period, investment drivers will remain characteristically similar and that there are no foreseen extraordinary expenditures.

TABLE 1-4: PROPOSED CAPITAL INVESTMENTS

CATEGORY	Bridge Year	Forecast Period ($'000s)				
	2025	2026	2027	2028	2029	2030
System Access	$4,559	$4,890	$4,423	$4,552	$4,651	$4,752
System Renewal	$9,863	$9,656	$10,665	$10,233	$10,848	$11,320
System Service	$5,226	$2,245	$2,191	$2,480	$2,528	$2,419
General Plant	$3,899	$3,433	$3,034	$2,560	$2,870	$2,995
TOTAL EXPENDITURE	$23,548	$20,224	$20,313	$19,825	$20,897	$21,486
Capital Contributions	-$1,545	-$1,671	-$1,699	-$1,749	-$1,783	-$1,819
NET CAPITAL EXPENDITURES	**$22,003**	**$18,553**	**$18,614**	**$18,076**	**$19,114**	**$19,668**

1.4.4 CAPITAL EXPENDITURES

CAPITAL EXPENDITURES FOR THE 2026 TEST YEAR

EPI is forecasting a decrease in total capital spending in the 2026 Test Year in comparison to the 2025 Bridge Year. This year-over-year decrease is driven primarily by the 2025 installation of a new breaker at St. Thomas Edgeware TS, along with a new associated feeder providing approximately 14 MW of additional planning capacity to address existing capacity constraints in St. Thomas. Subsequent to these investments, forecasted capital expenditures remain relatively stable between 2026 through 2030.

As shown below in Table 1-5, gross capital expenditures (excluding capital contributions) forecast for the 2026 Test Year are $20.2M. This represents a $9.8M increase over the 2016 OEB Approved Proxy representing combined EPI and STEI capital expenditures of $10.5M, a 93% increase, representing a compound annual growth rate of 6.8%. Capital contributions have increased by $1.2M, or 240% over the same timeframe, for a net increase in capital spending of $8.6M or 86%, representing a compound annual growth rate of 13.0%. Table 1-5 below provides a further breakdown of capital expenditures by category.

TABLE 1-5: 2016 OEB APPROVED PROXY VS. 2026 TEST YEAR CAPITAL EXPENDITURES

Line No.	Investment Category	2016 EPI OEB-Approved Plan	$'000's				
			2016 STEI	2016 OEB-Approved Proxy	2026 Test Year	Variance $	Variance %
1	System Access	$ 1,788	$ 204	$ 1,992	$ 4,890	$ 2,898	145.5%
2	System Renewal	$ 3,749	$ 1,190	$ 4,939	$ 9,656	$ 4,717	95.5%
3	System Service	$ 1,192	$ 213	$ 1,405	$ 2,245	$ 840	59.8%
4	General Plant	$ 1,519	$ 608	$ 2,127	$ 3,433	$ 1,306	61.4%
5	**Total Expenditure**	**$ 8,248**	**$ 2,214**	**$ 10,462**	**$ 20,224**	**$ 9,762**	**93.3%**
6	Capital Contribution	$ (375)	$ (117)	$ (492)	$ (1,671)	$ (1,179)	239.6%
7	**Net Capital Expenditures**	**$ 7,873**	**$ 2,097**	**$ 9,970**	**$ 18,553**	**$ 8,583**	**86.1%**

Note: The STEI 2015 OEB Approved CAPEX, as approved in EB-2014-0113, is inflated above to 2016 amounts by STEI's 2016 OEB Approved IRM net price cap index adjustment of 1.8%.

The increase in gross capital expenditures over the 11-year period between 2016 and 2026 reflects a combination of renewal of deteriorating assets, as well as system growth and strategic investments in modernization and reliability, taking place amidst external cost pressures driven by inflation and global supply chain challenges. In response, EPI has implemented collaborative procurement strategies, leveraged joint purchasing arrangements, and adopted flexible project management approaches to ensure project delivery and affordability while maintaining system reliability.

System Access expenditures have increased from $2.0M in the 2016 OEB Approved Proxy to $4.9M in 2026, representing an increase of $2.9M, or 146%, representing a compound annual growth rate of 9.4%. These largely non-discretionary investments reflect EPI's obligations as a licensed distributor to accommodate new customer connections, asset relocations, and third-party requests. Between 2019 and 2022, EPI experienced significant residential and subdivision growth in communities such as St. Thomas, Strathroy, Mt. Brydges, and Chatham, accompanied by significant Fibre-to-the-Home deployment driven by multiple Internet Service Providers. Although residential growth has moderated since 2023, System Access needs remain elevated relative to 2016 levels.

System Renewal expenditures increase from $4.9M in 2016 to $9.7M in 2026, a variance of $4.7M, or 96%, representing a compound annual growth rate of 6.9%. System Renewal investments are critical to sustain system reliability though replacement and refurbishment of deteriorating infrastructure across EPI's 17 communities, as identified through ongoing ACAs. A key component is EPI's voltage conversion program, which phases out legacy low-voltage systems with modern 27.6 kV infrastructure, avoiding costly station rebuilds, reducing line losses and improving capacity and flexibility to accommodate new technologies. Another key driver is EPI's phased smart meter replacement. As an approved early adopter of smart meters, EPI started installing smart meters between 2006 and 2007 and these now require life cycle replacement. Additionally, EPI has adopted a new design standard for residential transformers, moving to a baseline of 6 kVA per customer, with an option for 12 kVA, and will continue to monitor and respond to changing customer electricity needs by planning and building the distribution system for reasonable forecasted load growth.

System Service expenditures increase from $1.4M in 2016 to $2.2M in 2026, a variance of $0.8M or 60%, representing a compound annual growth rate of 4.8%. These investments support reliable operations and evolving customer expectations for system performance and modern grid capabilities. Key drivers include the deployment of intelligent sectionalizing switches and reclosers for faster fault detection and restoration, new feeder ties and reconductoring projects to improve operational flexibility and reduce outage impacts, and a system modernization initiative in Mt. Brydges to replace low-voltage systems and expand capacity. Ongoing enhancements to EPI's Control Room capabilities and asset management systems further support proactive system monitoring and data-driven operational decisions. Notably, since 2017, EPI's reclosers and load break switches have mitigated an estimated 124,500 customer outage hours across EPI's territory.

General Plant expenditures are forecast to increase from $2.1M in 2016 to $3.4M in 2026, a variance of $1.3M, or 61%, representing a compound annual growth rate of 4.9%. These investments are essential to supporting safe, effective utility operations. A significant portion of this increase relates to investments in IT infrastructure and cybersecurity, which are critical to safeguarding system integrity, enhancing operational resiliency, and aligning with evolving regulatory and industry standards. Other key initiatives include server upgrades, data protection enhancements, advanced analytics and the ongoing modernization of digital platforms. EPI has also invested in facility updates focused on maintaining core building systems at its operating centres, including the previously deferred replacement of the Chatham Operations Centre roof, scheduled over a two-year period starting in 2025. Other facility updates, including HVAC and yard surface, continue to be deferred to prioritize System Renewal and other key initiatives described above. Lifecycle replacement of fleet vehicles, tools, and construction equipment remains vital to ensure safe, reliable service delivery while mitigating operational risks.

Capital contributions are projected to increase from $0.5M in 2016 to $1.7M in 2026, an increase of $1.2M, or 240% representing a compound annual growth rate of 9.4%. This growth reflects customer-driven activity, including new connections, subdivisions, and third-party infrastructure projects. These contributions offset a portion of EPI's gross capital expenditures, reducing the net capital funding requirement borne by ratepayers.

1.4.5 Operations, Maintenance and Administration Expense

EPI is proposing the recovery through distribution rates of $21.1M in OM&A expenses for the 2026 Test Year. EPI's 2016 OEB Approved Proxy amount for OM&A expenses was $14.0M. This represents a compound annual growth rate of 4.3%, which is indicative of prudent and responsible cost management, taking into account strategic investments in the development of a modernized workforce and the sustained high-inflationary environment since the pandemic. Table 1-6 below summarizes the changes.

TABLE 1-6: CHANGES IN OM&A BETWEEN 2016 OEB APPROVED PROXY AND 2026 TEST YEAR

Item	Amount	Reference
2016 OEB Approved Proxy OM&A	**$13,962,859**	
Cost Drivers:		
Change in Operating Portion of Salaries, Wages, and Benefits	$5,620,649	Exhibit 4 - 4.4
Merger Synergies	($1,817,597)	Exhibit 1 - 1.11.4
Inflation on Non-Labour Items	$2,124,397	Exhibit 4 - 4.1.5
Enhanced LEAP Funding	$276,180	Exhibit 4 - 4.3.3
Cybersecurity and Licensing Costs	$520,440	Exhibit 4 - 4.3
Bad Debt Expense	$257,552	Exhibit 4 - 4.3.4
Other Immaterial Items	$183,387	
2026 Test Year OM&A	**$21,127,866**	

Forecast OM&A expenditures for the 2026 Test Year have been derived through a detailed budgeting and business planning process aligned with EPI's Strategy and Core Values. These expenditures are required for EPI to maintain distribution business service quality and reliability standards in compliance with the Distribution System Code and requirements of other regulatory bodies (Independent Electricity System Operator ("IESO"), Ministry of Energy, Electrical Safety Authority ("ESA"), etc.) while also responding to customer needs and preferences.

Between 2016 and 2026, the business landscape and environment in which EPI operates changed substantially, and continues to evolve into the Test and subsequent years . Since EPI's last rebasing in 2016, there have been several significant business environment changes that impact operating costs. Some of these business changes include shifting labour demographics, digital transformation and cybersecurity, adoption of AI-enabled technologies and regulatory environment changes. Please see Exhibit 4, Section 4.1.6 for further details regarding the Business Environment changes. EPI has embraced these changes and worked to respond to them cost-effectively, without adversely impacting customer service.

Notably, the OM&A cost increase between 2016 to 2026 reflects EPI's evolving workforce needs. EPI's workforce strategy is grounded in the principle that a skilled and well-supported workforce is essential to delivering safe, reliable, and responsive service in a rapidly evolving energy sector. A competitive and equitable compensation system – paired with a respectful and empowering working environment – is essential to attracting, developing, and retaining skilled employees. A modernized workforce is needed to meet rising customer expectations, respond to legislative and regulatory requirements, and manage increased operational complexity; including implementation of technological advancements. Accordingly, the EPI workforce has significantly evolved in the past decade.

In this context, the primary drivers for the increased OM&A costs shown in Table 1-6 above are more fully described as follows:

- **Increase in salaries, wages and benefit costs charged to OM&A of $5.6M**. Increases in employee compensation within OM&A are largely attributed to strategic investments in building a modernized workforce capable of meeting evolving customer expectations, addressing legislative and regulatory demands, and managing growing operational complexity. These increases are further influenced by inflationary pressures and contractual wage and benefit adjustments.

- **Merger synergies of $1.8M resulting from the EPI/STEI merger** have been realized, primarily driven by reductions in administrative costs. These savings were achieved through the consolidation of regulatory and finance functions, as well as the internalization of billing operations.

- **Increase in inflation on non-labour items of $2.1M**. Inflation has had a sustained impact on EPI's non-labour OM&A expenditures from 2016 through to the 2026 Test Year. Over this period, EPI has experienced steady increases in the cost of materials, contracted services, fuel, and other non-labour inputs essential to the delivery of safe and reliable electricity distribution service. These inflationary pressures reflect broader macroeconomic trends, including supply chain constraints, commodity price volatility, and rising service rates from third-party vendors.

- **Increase in LEAP funding of $276k.** The 2026 Test Year includes enhanced LEAP funding in base rates, reflecting the OEB's EB-2023-0135 order effective March 1, 2024. EPI has been providing higher levels of assistance to vulnerable customers through its social agency partners, with incremental contributions beyond base rates tracked in a dedicated sub-account of Account 1508. EPI proposes to dispose of this balance in this Application (see Exhibit 9, Section 9.5.1), and, given the continued need for enhanced assistance, has incorporated this increase in its forecast.

- **Increase in cybersecurity and licensing costs of $520k**. Cybersecurity, by necessity, has become a critical and integrated part of utility operations. Collaboration across the industry is essential to effectively counter the growing array of cyber threats. EPI's cybersecurity program includes regular penetration testing and tabletop exercises to ensure readiness in the event of an attack.
- **Increase in bad debt expense of $258k**. The projected bad debt expense for 2026 reflects a continued upward trend in arrears, driven by rising financial stress among customers and broader economic conditions, including increasing unemployment in southern Ontario. This forecast accounts for both recent increases in bad debt levels and the typical lag between economic downturns and their full financial impact on collections.

The above drivers are further described in Exhibit 4, Section 4.2.

1.4.6 Cost of Capital

EPI has followed the OEB's EB-2024-0063 Decision and Order (the "2025 Cost of Capital Report"), dated March 27, 2025, to determine its capital structure and the 2026 cost of capital parameters presented in this evidence. EPI confirms that there have been no deviations from the OEB's cost of capital methodology.

EPI acknowledges these rates are subject to change when the OEB issues the 2026 cost of capital parameters. EPI will update its short-term debt and return on equity rates based on the 2026 cost of capital parameters prior to the rate order being finalized in this proceeding. Table 1-7 below presents EPI's proposed capital structure and cost of capital parameters, and the resulting weighted average cost of capital.

Table 1-7: 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%		$106,594,385	4.34%	$4,627,064
Short-term Debt	4.00%	(1)	$7,613,885	3.91%	$297,703
Total Debt	60.0%		$114,208,269	4.31%	$4,924,767
Equity					
Common Equity	40.00%		$76,138,846	9.00%	$6,852,496
Preferred Shares			$ -		$ -
Total Equity	40.0%		$76,138,846	9.00%	$6,852,496
Total	100.0%		$190,347,116	6.19%	$11,777,263

1.4.7 Cost Allocation and Rate Design

Cost Allocation

For the purposes of this Application, EPI has followed the cost allocation policies as outlined in the OEB's reports of November 28, 2007 *Report of the Board on Application of Cost Allocation for Electricity Distributors* and March 31, 2011 *Review of Electricity Cost Allocation Policy* (the "Cost Allocation Reports"), and the 2026 Cost Allocation Model ("CA Model") issued on February 5, 2025, and submitted the CA Model to reflect 2026 Test Year costs, customer numbers, and demand values.

The data used in the CA Model is consistent with EPI's cost data supporting the proposed 2026 revenue requirement outlined in this Application. The breakout of Assets, Capital Contributions, Depreciation, Accumulated Depreciation, Customer Data and Load Data by Primary, Line Transformer and Secondary categories were developed from the best data available to EPI, its Engineering Records, and its Customer and Financial Information Systems. EPI has also developed utility-specific load profiles based on recent actual consumption data for the purpose of informing demand allocators.

As shown in Table 1-8 below, the resulting 2026 Cost Allocation Study indicates the Revenue to Cost ("R-C") Ratios for the Large Use and Street Lighting rate classes are outside the OEB's range. For 2026, it is proposed these ratios be brought within the OEB's range and the Residential rate class be adjusted slightly upward within the OEB's range in order to maintain revenue neutrality.

TABLE 1-8: PROPOSED REVENUE TO COST RATIOS

Line No.	Rate Class	Previously Approved Ratios (Note 1)	Status Quo Ratios (Per CA Model)	Proposed Ratios	Policy Range
1	Residential	98.9%	96.6%	97.8%	85% to 115%
2	General Service < 50 kW	110.5%	106.8%	106.8%	80% to 120%
3	General Service > 50 - 4,999 kW	98.6%	100.4%	100.4%	80% to 120%
4	Large Use	85.0%	131.5%	115.0%	85% to 115%
5	Unmetered Scattered Load	110.5%	108.4%	108.4%	80% to 120%
6	Sentinel Lighting	86.3%	100.0%	100.0%	80% to 120%
7	Street Lighting	110.5%	178.5%	120.0%	80% to 120%
8	Embedded Distributor (Note 2)	100.0%	n/a	n/a	n/a

Note 1: These Revenue to Cost ratios relate to the former EPI, as approved in EB-2015-0061.
Note 2: The Embedded Distributor rate class is n/a for status quo and proposed ratios as EPI is proposing elimination of this rate class as part of this Application.

In the Application, EPI proposes the elimination of the Embedded Distributor Rate Class. Please refer to Exhibit 7, Section 7.3.4 for more information on the proposed elimination of this rate class.

RATE DESIGN

In this Application, EPI seeks to harmonize distribution rates across its existing two rate zones. EPI prioritized a full and straight-forward harmonization of all rates across its Entegrus-Main and Entegrus-St. Thomas rate zones as an ideal outcome. The full harmonization of all existing rates, rather than the continuation of some or all rate zone separations or the creation of net new rate classes, carries significant efficiency benefits and is also better reflective of underlying cost structures as a result of the merger of EPI and STEI into a single consolidated entity. In addition, the harmonization of rate classes across all rate zones is supported by EPI's customers, as confirmed in the customer engagement presented in Exhibit 1, Section 1.7.3 and in Attachment 1-G.

The Entegrus-Main and Entegrus-STT rate zones currently have the same rate classifications with two exceptions. Entegrus-Main has two separate rate classes for customers with loads above 50 kW (GS > 50 to 4,999 kW and Large Use), and Entegrus-STT has one (GS > 50 kW). Further, Entegrus-Main has an Unmetered Scattered Load rate class and Entegrus-STT does not. EPI proposes to maintain the Large Use and Unmetered Scattered Load rate classes, though there are no former Entegrus-STT rate zone customers that will be migrating to the Large Use and Unmetered Scattered Load rate classes which will now apply in this service territory.

As detailed in Section 7.3.3 of Exhibit 7, in its 2016 COS Application (EB-2015-0061), EPI received approval for Standby rates on a final basis for its GS > 50 kW and Large Use rate classes, equal to the variable distribution charge for each rate class, respectively. As noted above, EPI is seeking to harmonize its two rate zones into a single tariff sheet. While the Entegrus-Main rate zone currently has customers to whom the approved Standby charges apply, the Entegrus-STT rate zone does not. EPI is proposing to maintain the final approved Standby charges in the harmonized tariff sheet. In Phase Two of EPI's Customer Engagement, EPI asked customers about extending standby rates to customers in the Entegrus-STT rate zone and the majority of customers were supportive (see Exhibit 1, Attachment 1-G for the Phase Two Customer Engagement report).

Consistent with recent OEB decisions, EPI proposes to apply the blended fixed/variable revenue proportions implied in the current rates to design the proposed monthly service charge for rate classes, with the exception of the GS < 50 kW, GS > 50-4,999 kW, Large Use, and Unmetered Scattered Load rate classes. For these rate classes, the current fixed/variable proportions result in a monthly fixed charge above the fixed charge ceiling as calculated in the cost allocation study. Where reliance on the existing fixed/variable split of revenue resulted in a fixed charge above the ceiling identified in the cost allocation study, EPI has proposed holding fixed charges at the higher of current levels, based on the blended existing fixed charges of EPI's rate classes, or the fixed charge ceiling in the cost allocation study.

Table 1-9 below provides a comparison of the 2025 Current Distribution Rates (by rate class) to the harmonized 2026 Proposed Distribution Rates.

TABLE 1-9: COMPARISON OF CURRENT AND PROPOSED DISTRIBUTION RATES

Line No.	Rate Class	Monthly Service Charge			Distribution Volumetric Charge			
		2025 Approved	2026 Proposed	% Difference	Unit	2025 Approved	2026 Proposed	% Difference
1	**Entegrus-Main**							
2	Residential	$30.06	$36.59	21.72%	kWh	$0.0000	$0.0000	n/a
3	General Service < 50 kW	$37.73	$38.96	3.26%	kWh	$0.0123	$0.0181	47.15%
4	General Service > 50-4,999 kW	$122.36	$117.84	-3.69%	kW	$4.0526	$4.8701	20.17%
5	Large Use	$1,867.15	$1,867.15	0.00%	kW	$2.8514	$2.8970	1.60%
6	Unmetered Scattered Load Connections	$10.09	$10.09	0.00%	kWh	$0.0018	$0.0059	227.78%
7	Sentinel Lighting Connections	$9.19	$9.96	8.38%	kW	$0.8230	$1.0185	23.75%
8	Street Lighting Connections	$1.40	$1.76	25.71%	kW	$1.1738	$0.6235	-46.88%
9	**Entegrus-STT**							
10	Residential	$32.31	$36.59	13.25%	kWh	$0.0000	$0.0000	n/a
11	General Service < 50 kW	$29.62	$38.96	31.53%	kWh	$0.0201	$0.0181	-9.95%
12	General Service > 50-4,999 kW	$92.31	$117.84	27.66%	kW	$4.4195	$4.8701	10.20%
13	Sentinel Lighting Connections	$5.97	$9.96	66.83%	kW	$7.2274	$1.0185	-85.91%
14	Street Lighting Connections	$4.56	$1.76	-61.40%	kW	$0.0447	$0.6235	1294.85%

1.4.8 Deferral and Variance Accounts

As outlined in Exhibit 9, EPI is requesting approval of the disposition of Group 1 and Group 2 Deferral and Variance Accounts ("DVAs") in the amount of $426,796 as a collection from customers. This includes an RSVA – Global Adjustment amount of $215,771 owed to EPI by Non-RPP customers only. The remaining amount of $211,025 is to be collected from all customers. EPI is proposing a one-year disposition period for all DVAs.

Please refer to Section 1.10.7 regarding Account 1508 – Sub-Account – OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account and EPI's proposal to use the OEB's generic Account 1522 DVA.

As part of its proposal to harmonize the legacy Entegrus and St. Thomas EPI rate zones, EPI proposes to dispose of all Group 1 and Group 2 DVA balances on a harmonized basis, effective May 1, 2026. The reasoning behind this request is described in Exhibit 9, Section 9.3. Further, EPI proposes that future dispositions of all DVAs balances be accounted for and completed on a consolidated basis. This methodology would ensure consistency among the dispositions proposed in this Application and future balances.

1.4.9 Bill Impacts

In preparing for this Application, EPI undertook customer engagement activities which noted the importance of balancing reasonable and affordable rates. A summary of the bill impacts for typical customers in all customer classes is provided in Table 1-10 below. EPI notes that the majority of the proposed bill impacts are below 5% increases on a total bill basis, and that no rate class exceeds the 10% threshold on a total bill basis. Accordingly, EPI submits that the bill impacts of its proposed 2026 distribution rates are reasonable and do not require rate mitigation.

TABLE 1-10: 2026 PROPOSED BILL IMPACTS TOTAL BILL

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	$135.72	$4.38	3.3%
3	General Service < 50 kW	RPP	2,000	-	$326.91	$334.69	$7.78	2.4%
4	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$29,594.54	$28,816.37	-$778.17	-2.6%
5	Large Use	Non-RPP	2,700,000	5,500	$441,816.86	$428,528.94	-$13,287.92	-3.0%
6	Unmetered Scattered Load	RPP	150	-	$30.37	$30.66	$0.29	1.0%
7	Sentinel Lighting	RPP	150	1	$38.10	$38.00	-$0.10	-0.2%
8	Street Lighting	Non-RPP	345,000	2,300	$74,545.67	$77,516.84	$2,971.17	4.0%
9	**Entegrus - St. Thomas**							
10	Residential	RPP	750	-	$130.70	$135.72	$5.01	3.8%
11	General Service < 50 kW	RPP	2,000	-	$329.44	$334.69	$5.24	1.6%
12	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$28,215.20	$28,816.37	$601.16	2.1%
13	Sentinel Lighting	RPP	150	1	$39.38	$38.00	-$1.37	-3.5%
14	Street Lighting	Non-RPP	345,000	2,300	$72,783.65	$77,516.84	$4,733.19	6.5%

As described in Section 1.7.3 below, Phase 1 customer engagement showed that customers prioritize delivery of electricity at reasonable rates, while also ensuring reliable service, and customers recognize that this may require supporting necessary investments even if it has a direct impact on their bill. In Phase 2 customer engagement, the majority of customers supported spending in accordance with EPI's plan or more than its plan.

The bill impacts to be used for the Notice of Application are provided as Sub-Total A, which represents the bill impacts that result only from distribution cost changes, presented in Table 1-11 below.

TABLE 1-11: 2026 PROPOSED BILL IMPACTS – BREAKDOWN BY SUBTOTAL

Line No.	Rate Class	kWh	kW	Sub-Total A Excl. Pass Through		Sub-Total B Distribution		Sub-Total C Delivery		Sub-Total D Total Bill	
1	**Entegrus-Main**										
2	Residential	750	-	$ 5.09	16.9%	$ 4.50	12.1%	$ 4.39	8.4%	$ 4.38	3.3%
3	General Service < 50 kW	2,000	-	$ 9.03	14.3%	$ 7.25	9.0%	$ 7.81	6.7%	$ 7.78	2.4%
4	General Service > 50 - 4,999 kW	162,500	500	$ (4.07)	-0.2%	$ (638.02)	-17.0%	$ (654.52)	-8.8%	$ (778.17)	-2.6%
5	Large Use	2,700,000	5,500	$ (1,191.30)	-6.7%	$(10,246.75)	-28.6%	$(11,192.20)	-14.0%	$(13,287.92)	-3.0%
6	Unmetered Scattered Load	150	-	$ 0.51	4.9%	$ 0.36	3.1%	$ 0.29	2.1%	$ 0.29	1.0%
7	Sentinel Lighting	150	1	$ 0.31	3.1%	$ 0.04	0.3%	$ (0.08)	-0.5%	$ (0.10)	-0.2%
8	Street Lighting	345,000	2,300	$ 3,958.76	41.9%	$ 2,419.83	17.6%	$ 2,701.81	10.3%	$ 2,971.17	4.0%
9	**Entegrus-STT**										
10	Residential	750	-	$ 2.84	8.8%	$ 5.91	16.6%	$ 5.01	9.7%	$ 5.01	3.8%
11	General Service < 50 kW	2,000	-	$ 2.14	3.1%	$ 9.94	12.7%	$ 5.22	4.4%	$ 5.24	1.6%
12	General Service > 50 - 4,999 kW	162,500	500	$ 105.23	4.6%	$ 813.73	35.3%	$ 496.08	7.9%	$ 601.16	2.1%
13	Sentinel Lighting	150	1	$ (2.87)	-21.8%	$ (1.56)	-11.3%	$ (1.22)	-6.5%	$ (1.37)	-3.5%
14	Street Lighting	345,000	2,300	$ 2,819.57	26.6%	$ 5,599.81	52.9%	$ 4,112.40	16.6%	$ 4,733.19	6.5%

1.5 Administration

In accordance with the OEB's Filing Requirements, this section of the Application provides information relating to the administration of this Application.

1.5.1 Certification of Evidence

EPI provides certification in Attachment 1-A that:

- The evidence filed, including the models and appendices, are accurate, consistent, and complete to the best of their knowledge.
- The Application and any evidence filed in support of this Application do not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction Confidential Filings, as applicable).
- EPI has the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts, regardless of whether the accounts are proposed for disposition.

1.5.2 Board of Directors Certification

EPI provides a letter from its Board of Directors certifying that it is aware of and approves the submission of the Application. Please refer to Attachment 1-A.

1.5.3 Filing Requirements Checklist

EPI has completed the OEB's 2026 Cost of Service Filing Checklist. Please refer to the standalone excel document entitled EPI_2026_COS_Checklist_20250829. EPI has not deviated from the Filing Requirements.

1.5.4 Primary Contact Information

The Applicant's Address for Service:

Entegrus Powerlines Inc.
320 Queen Street, P.O. Box 70
Chatham, Ontario
N7M 5K2
Email: regulatory@entegrus.com

Contacts:

President and CEO
Mr. Jim Hogan
Telephone: 519-352-6300 x 4277
Email: jim.hogan@entegrus.com

Chief Financial Officer and VP IT
Mr. Chris Towne
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Email: chris.towne@entegrus.com

Chief Regulatory Officer and VP Human Resources
Mr. David Ferguson
Telephone: 519-352-6300 x 4558
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Primary Application Contact

Director of Regulatory
Ms. Carly Shaw
Telephone: 519-352-6300 X 4335
Email: carly.shaw@entegrus.com

1.5.5 Legal Representation

Borden Ladner Gervais LLP
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Toronto, Ontario
M5H 4E3

John Vellone
Partner

Telephone: 416-367-6730
Cell: 416-801-7207
Email: jvellone@blg.com

Colm Boyle
Partner
Telephone: 416-367-7273
Email: cboyle@blg.com

1.5.6 Internet Address and Social Media

EPI's main webpage is the following: www.entegrus.com

The Application and related materials will be posted on EPI's website and will be available for viewing at the following internet address: http://www.entegrus.com/regulatory.

EPI social media channel addresses are as follows:

Facebook: www.facebook.com/entegrus

X/Twitter: www.x.com/entegrus

YouTube: www.youtube.com/entegrus

Instagram: www.instagram.com/entegrus

The Application will also be available on the OEB's website at www.oeb.ca, under OEB File Number EB-2025-0044.

1.5.7 Statement of Publication

EPI will follow the OEB's instructions regarding the publication of Notice of Application. EPI proposes to publish the Notice of Application on its website.

1.5.8 Materiality Threshold

Chapter 2 of the Filing Requirements sets out the materiality levels based on the magnitude of the revenue requirement. EPI's revenue requirement is greater than $10 million and less than $200 million, therefore its materiality level is 0.5% of distribution revenue requirement. EPI's materiality threshold for the 2026 Test Year is $197,577 as provided in Table 1-12 below. EPI has used a threshold of $195,000 for assessing materiality for the purposes of this Application.

TABLE 1-12: EPI'S MATERIALITY THRESHOLD FOR THE 2026 TEST YEAR

Description	2026 Test Year
Distribution Revenue Requirement	$ 39,515,303
Materiality Threshold	0.5%
Materiality Calculated	$ 197,577
Materiality Used	$ 195,000

1.5.9 Form of Hearing

The bill impacts resulting from this Application are within the OEB's requirements, as shown in Section 1.4.9. Accordingly, EPI requests that this Application be disposed of by way of a written hearing in order to expedite the proceeding.

1.5.10 Proposed Effective Date of Rate Order

EPI requests that the OEB make its Rate Order effective May 1, 2026 in accordance with the Filing Requirements.

In the event that the OEB is unable to provide a Decision and Order in this application for implementation by the Applicant as of May 1, 2026, the Applicant requests that the OEB declare its current rates interim, effective May 1, 2026, pending the implementation of the OEB's Rate Order for the 2026 rate year.

1.5.11 Changes to Methodologies Used in Previous Applications

The pro-forma projections for the 2026 Test Year have been prepared in accordance with EPI's usual process (including the use of Modified International Financial Reporting Standards ("MIFRS") accounting), with the following exceptions:

- Rates for distribution and sales of electricity are assumed to be constant for the entire 2026 Test Year;
- Regulatory costs have been normalized over the five-year application period; and,
- Affiliate FTEs (2.8 FTEs) have been added to Appendix 2-K starting with 2016 Actuals.

1.5.12 OEB Directions from Previous Decisions and/or Orders

Below is a summary of directives from previous decisions and/or orders and a description of how these are addressed by EPI in this Application.

EPI 2016 Cost of Service Application (EB-2015-0061)

In EB-2015-0061, an accounting order was issued related to Account 1508 – Sub-Account OPEB Forecast Cash vs. Forecast Accrual Differential. Please refer to Section 1.10.7 for additional details.

EPI/STEI MAADs Application (EB-2017-0212)

In EB-2017-0212, the OEB approved an eight-year deferred rebasing period for the amalgamated EPI, beginning with the 2018 merger of EPI and STEI and extending through to 2026. As part of that Decision and Order, an Earnings Sharing Mechanism ("ESM") was established under which earnings exceeding 300 basis points above regulatory ROE would be shared 50:50 with rate payers during years six through eight of the rebasing deferral period. The OEB also accepted EPI's commitment to file a consolidated DSP in 2021.

EPI has met the requirements of the 8-year deferred rebasing period by filing this Application. The ESM threshold was not exceeded in 2023 or 2024 (as seen in the 2024 Scorecard results, shown in Attachment 1-D) and accordingly no earnings sharing was required. The ESM threshold is not forecasted to be exceeded in 2025. EPI filed the consolidated DSP on September 15, 2021; a copy is provided in Exhibit 2, Attachment 2-C (DSP), Attachment A.

1.5.13 Conditions of Service

The current version of EPI's Conditions of Service is available on EPI's website at http://www.entegrus.com/conditions-service

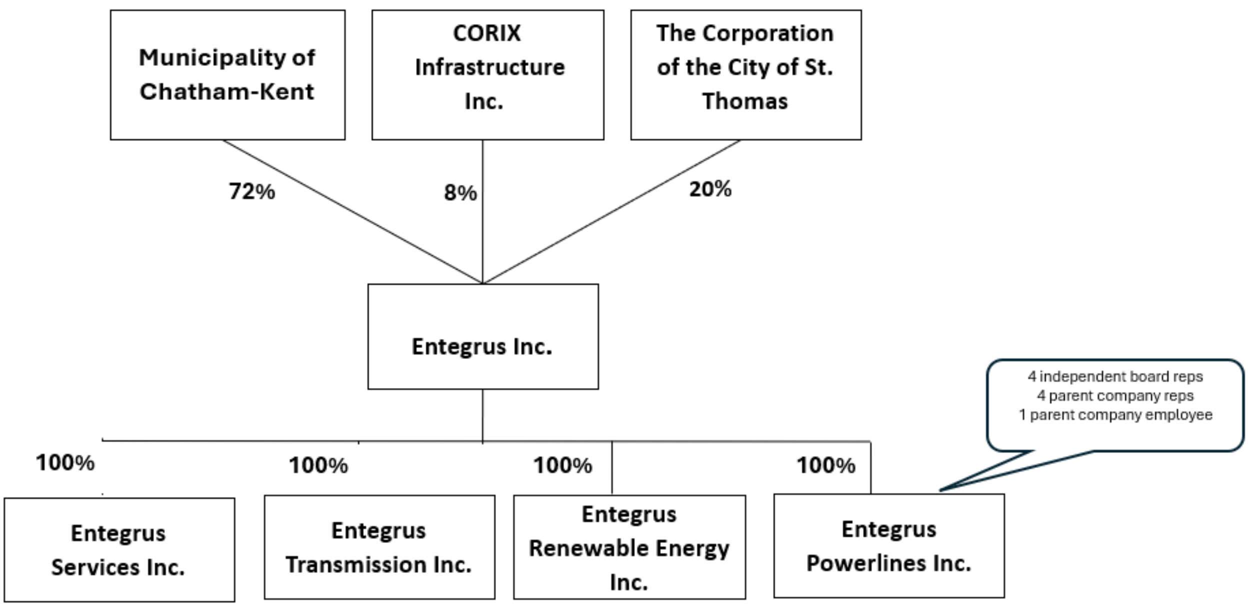
EPI has updated its Conditions of Service document since its last Cost of Service to incorporate harmonization of the operational and customer service practices of Legacy EPI and the former STEI, other minor clarifications as well as to update for OEB directives and other regulatory requirements. EPI provided notification of the changes to its Conditions of Service in accordance with DSC Section 2.4.8 to customers and provided customers the opportunity to provide feedback.

EPI confirms that there are no rates or charges listed in the Conditions of Service that are not on EPI's Tariff of Rates and Charges.

1.5.14 Corporate and Utility Organizational Structure

The following chart illustrates the corporate structure of the Entegrus Group, and the organizational relationship between EPI and its shareholder and its affiliates:

FIGURE 1-1: THE ENTEGRUS GROUP CORPORATE STRUCTURE



Entegrus Inc. and EPI are not planning on any changes to its corporate or operational structure at this time.

Organization of Entities

ENTEGRUS INC.

Entegrus Inc., incorporated September 22, 2000 (originally as Chatham-Kent Energy Inc.) under the Business Corporation Act (Ontario), is the parent holding company of EPI. Entegrus Inc. is 72% owned by the Municipality of Chatham-Kent, 8% by Corix Utilities Inc. (“Corix”) and 20% by the Corporation of the City of St. Thomas.

CORIX INFRASTRUCTURE INC.

Corix is indirectly owned by British Columbia Investment Management Corporation, one of North America’s largest institutional investors. Corix and its affiliates bring low-carbon energy systems to life by building and operating enduring infrastructure for communities across North America.

ENTEGRUS SERVICES INC.

Entegrus Services Inc. (“ESI”) owns and operates an unregulated data centre located in Chatham, Ontario. ESI also owns and maintains a land corridor running from Tilbury, Ontario to St. Thomas, Ontario.

Until December 31, 2014, ESI also provided billing, collection, administration, financial and regulatory services to EPI, the Chatham-Kent Public Utilities Commission, the Municipality of Strathroy-Caradoc and the Municipality of Dutton-Dunwich. On December 31, 2014, the utility-related assets of EPI’s unregulated affiliate, ESI, were transferred to EPI. Subsequently, on January 1, 2015, the employees of ESI were transferred to EPI. ESI previously provided Customer Service and Administrative support to EPI.

In 2022, the above-noted land corridor was transferred from Entegrus Transmission Inc. (“ETI”) to ESI. ESI provides land easements to other parties and provides certain land maintenance services on the corridor; ESI does not own or operate transmission assets.

ENTEGRUS TRANSMISSION INC.

ETI was previously a licensed electricity transmitter and owned and maintained the above-described land corridor running from Tilbury, Ontario to St. Thomas, Ontario, now owned by ESI.

ENTEGRUS RENEWABLE ENERGY INC.

Entegrus Renewable Energy Inc. ("EREI") is a wholly owned subsidiary of Entegrus Inc. EREI invests in wind energy developments in southwestern Ontario and represents Entegrus Inc.'s commitment to renewable energy portfolio and supporting sustainable energy initiatives.

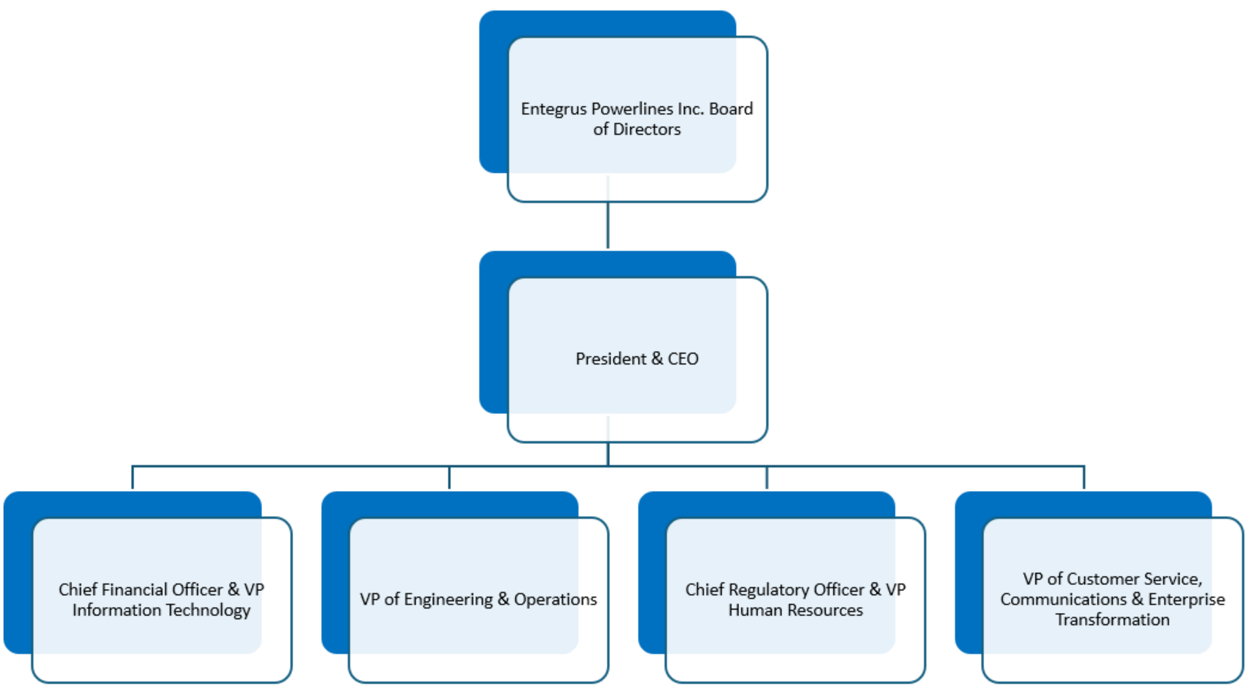
ENTEGRUS POWERLINES INC.

EPI is a wholly-owned subsidiary of Entegrus Inc. EPI owns, operates and manages the assets associated with the distribution of electrical power within the service territory described above and as set out in Electricity Distribution Licence ED-2002-0563.

EPI also provides billing and collection services to the Chatham-Kent Public Utilities Commission, the Corporation of the City of St. Thomas and the Village of Newbury.

The following chart shows the management organizational structure of EPI.

FIGURE 1-2: EPI ORGANIZATIONAL CHART



1.5.15 Corporate Governance

The EPI Directors are appointed by the Board of Directors of Entegrus Inc. A corporate entities relationship chart is shown above as Figure 1-1.

The Corporation of the City of St. Thomas and Corix each have the right to appoint one director to the Board of Directors of Entegrus Inc. and one director to the Board of Directors of EPI. Should either shareholder increase its non-equity interest in Entegrus Inc., the shareholder would then have the right to appoint one additional director. The Municipality of Chatham-Kent has the right to appoint the remaining Directors of Entegrus Inc., which may include the appointment of up to two (2) Municipal Council representatives.

Board of Directors and Independence

The Entegrus Inc. Board of Directors consists of nine (9) Directors and the EPI Board of Directors also consists of nine (9) Directors. The respective Board of Directors manage the business affairs of Entegrus Inc. and EPI, and each Board of Directors is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of the corresponding corporations.

Four (4) of the nine (9) EPI Directors are independent, in accordance with the OEB Affiliate Relationship Code (Section 2.1.2 (a)) requirement and EPI policy that one third of Directors be independent. In practice, EPI has ensured the facilitation of independent judgment by having a higher percentage of independent Board members who are strong professionals. Figure 1-1 above further describes the composition and independence of Directors.

Additional independence is facilitated by the involvement of the two minority shareholders (The Corporation of the City of St. Thomas and Corix) at the Entegrus Inc. Board level.

Board Mandate, Code of Conduct and Processes

The EPI Board of Directors Mandate and Charter and Code of Conduct (applicable to EPI and Entegrus Inc.), are provided in Attachment 1-C. These documents provide the foundation of the EPI Board processes.

The Board is a self-monitoring body that is accountable to the shareholder. Any infractions would be dealt with by the Chair.

The EPI President and CEO and the other senior leadership facilitate an orientation with new Directors, which includes:

- Review of the background and evolution of EPI;
- Review of the EPI mission, vision and core values;
- Review of the Ontario regulatory framework and current industry issues;
- Review of biographical information on other Directors and key personnel, including introductions as appropriate; and,
- A tour of the EPI facilities.

Further, a small budget is established for the continuing education of Directors. Directors may request additional Director Education and Training funding with approval by the Board of Directors.

BOARD COMMITTEES

The Entegrus Inc. Board of Directors has established four (4) Board Committees relating to governance of Entegrus Inc. and EPI. These Board Committees are as follows:

- Governance & Compensation Committee
- Environmental Health & Safety Committee
- Audit Committee
- Risk Committee

Board Committee member appointments are made from Directors on both Entegrus Inc. Board and the EPI Board. The members of the Audit Committee are required to be financially literate, which may include holding a CPA designation.

The Governance and Compensation Committee is responsible for the recruitment of new directors, including advertisement, interview and recommendation of nominees to the Board of Directors for approval.

1.5.16 Approvals Requested

In this proceeding, EPI is requesting the following approvals, effective May 1, 2026:

1. Approval to charge distribution rates to recover a service revenue requirement of $42.0M which includes a Revenue Deficiency of $5.9M as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8.

2. Approval of the DSP as outlined in Exhibit 2, Attachment 2-C.

3. Approval to harmonize the two existing EPI rate zones into one common EPI tariff sheet, including extending the existing OEB approved final standby rates to the former STEI rate zone, and including harmonized disposition of all DVAs as explained in Exhibit 9, Section 9.3.

4. Approval of revised Low Voltage rates as proposed and described in Exhibit 8.

5. Approval to adjust the Retail Transmission Rates – Network and Connection as detailed in Exhibit 8.

6. Approval of the proposed loss factors as detailed in Exhibit 8.

7. Approval of the rate riders for a one year disposition of the Group 1 and Group 2 Deferral and Variance Accounts as detailed in Exhibit 9.

EPI may request such other approvals as counsel for EPI may submit and the OEB may allow.

1.6 Distribution System Overview

1.6.1 The Evolution of Entegrus

Chatham Hydro was the largest predecessor to what is now EPI and was founded in 1914. Subsequently, Chatham-Kent Hydro ("CKH") was formed in 1998 as an amalgamation of eleven former Municipal Electric Utilities ("MEUs"). The amalgamation of the MEUs was part of the municipal amalgamation of approximately twenty-two municipalities and townships into what is now the Municipality of Chatham-Kent.

The former CKH was a local electricity distribution company (OEB Distributor Licence ED-2002-0563) serving the Ontario communities of Blenheim, Bothwell, Chatham, Dresden, Erieau, Merlin, Ridgetown, Thamesville, Tilbury, Wallaceburg, Wheatley, and certain designated land parcels in the Township of Raleigh, known as the Bloomfield Business Park.

On March 24, 2005, CKH's parent company, the former Chatham-Kent Energy Inc. ("CK Energy"), submitted MAAD application EB-2005-0255 requesting OEB approval to acquire all shares of Middlesex Power Distribution Corporation ("MPDC"). At that time, MPDC was a local distribution company (former OEB Distributor Licence ED-2003-0059) servicing the Ontario communities of Strathroy, Mount Brydges and Parkhill.

The OEB approved this acquisition in its Decision and Order issued on June 24, 2005. CK Energy's acquisition of MPDC subsequently closed June 30, 2005.

On October 15, 2008, MPDC submitted MAAD applications EB-2008-0332 and EB-2008-0350 requesting OEB approval to acquire all shares of the former Dutton Hydro Limited and the former Newbury Power Inc. and to amalgamate all entities into MPDC. The OEB approved these acquisitions and the amalgamation in its Decision and Order issued February 9, 2009. MPDC closed this transaction on April 30, 2009. Subsequently, MPDC served the distribution areas formerly licensed to each of MPDC, Dutton Hydro Limited & Newbury Power Inc. and maintained separate rate zones for each of these three areas.

On August 31, 2011, CKH applied to the OEB for leave to amalgamate MPDC with CKH (MAAD applications EB-2011-0328 and EB-2011-0329). On December 16, 2011, the OEB approved the amalgamation, and on January 11, 2012, CKH notified the OEB that this transaction was complete. On January 20, 2012, CKH received its amended Licence ED-2002-0563 and notification from the OEB that the MPDC Licence ED-2003-0059 was cancelled.

Subsequently, on January 31, 2012, CKH applied to the OEB to amend the company name on its Electricity Distribution Licence (ED-2002-0563) to EPI. The OEB approved this change and issued an updated Licence on February 24, 2012.

On August 28, 2015, EPI filed its comprehensive COS Application (EB-2015-0061) for distribution rates effective May 1, 2016, which also sought harmonization of the four previous rate zones of: (i) Chatham-Kent, (ii) Strathroy, Parkhill & Mt. Brydges, (iii) Dutton and (iv) Newbury. On February 3, 2016, EPI and the parties to the Application submitted a full Settlement Agreement on all matters to the OEB for approval. Subsequently, the OEB approved this Settlement Agreement in full in its Decision and Order dated March 17, 2016.

On July 21, 2017, EPI and STEI submitted a MAAD application (EB-2017-0212), seeking approval to amalgamate and continue as EPI. At that time, STEI was a local distribution company (former OEB Distributor Licence ED-2003-0523) servicing the city of St. Thomas, Ontario. On March 15, 2018, the OEB approved the amalgamation and the deferral of rate re-basing for the merged entity until 2026. Subsequently, EPI notified the OEB that the transaction was complete, effective April 1, 2018. On April 19, 2018, EPI received its amended Licence ED-2002-0563 and notification from the OEB that the STEI Licence ED-2002-0523 was cancelled.

As described in EB-2017-0212, EPI has maintained two separate rate zones for Entegrus-Main and Entegrus-St. Thomas since 2018. In this Application, EPI proposes harmonization to a single rate zone effective May 1, 2026.

As of December 31, 2024, EPI had approximately 63,600 metered customers and ranked approximately 12th in the Province of Ontario in terms of electrical utility size by number of metered customers.

1.6.2 Overview of Service Area

The EPI service territory covers 134 square kilometers of urban areas, encompassed within a 5,000 square kilometer geographic area located in southwestern Ontario between Windsor (to the west), London (to the east) and Sarnia (to the north).

The EPI service territory is more specifically described, in terms of additional specific inclusions and exclusions by community in EPI's distribution Licence (ED-2002-0563). In summary, EPI's service territory includes the following communities:

- *Those parts of the following former municipalities that the former dissolved public utilities served on December 31, 1997:*
  - *Town of Blenheim,*
  - *Town of Bothwell,*
  - *City of Chatham (including Bloomfield Business Park),*
  - *Town of Dresden,*
  - *Village of Erieau,*
  - *Police Village of Merlin,*
  - *Town of Ridgetown,*
  - *Village of Thamesville,*
  - *Town of Tilbury,*
  - *Town of Wallaceburg,*
  - *Village of Wheatley, and*
- *The former Town of Strathroy as of December 31, 2000.*
- *The former Police Village of Mount Brydges as of December 31, 2000.*
- *The former Town of Parkhill as of December 31, 2000.*
- *The Village of Dutton as of December 31, 1997, now within the Municipality of Dutton/Dunwich.*
- *The Village of Newbury as of November 7, 1998.*
- *The City of St. Thomas as of December 31, 1999.*

Please refer to Figure 3 below for a map of the EPI service territory.

Figure 3: Map of the EPI Service Territory

The EPI Distribution System

EPI has a total of approximately 993 circuit kilometers of primary wire and underground cable installed, of which approximately 584 km (59%) is overhead and 409 km (41%) is underground. Please refer to Table 1-13 below for more details on EPI distribution system characteristics.

TABLE 1-13: EPI DISTRIBUTION SYSTEM CHARACTERISTICS

No. of Phases	Overhead Line (km)					Underground Line (km)				
	2.4 kV	4.16 kV	8.32 kV	13.8 kV	27.6 kV	2.4 kV	4.16 kV	8.32 kV	13.8 kV	27.6 kV
1-Ø	-	25.6	32.0	-	110.9	-	13.1	17.8	-	319.0
2-Ø	0.9	-	-	-	0.0	0.2	-	-	-	-
3-Ø	9.4	52.1	32.9	3.6	316.6	1.2	8.5	1.0	-	48.1
Totals	10.3	77.7	64.9	3.6	427.5	1.4	21.6	18.8	-	367.0

The EPI distribution system has 16 distribution substations used to step down voltage from 27.6 kV for the remaining legacy low-voltage distribution system. A program to convert 2.4 kV and 4.16 kV distribution substations to 27.6 kV is further discussed in Exhibit 2 of the application.

For the original utilities that now comprise EPI, much of the economic growth occurred between 1950 and 1980. For example, the average age of EPI's substation transformers is more than 50 years. Exhibit 2 provides additional details on the composition of EPI's distribution system equipment and its ageing infrastructure.

1.6.3 IDENTIFICATION OF EMBEDDED OR HOST UTILITIES

Given the large geographic area served, the EPI distribution system electrical supply is sourced from a variety of Hydro One Networks Inc. ("HONI") transmission and distribution stations. Most of the system operates at a primary voltage level of 27.6 kV, with the exception of the communities of Erieau, Merlin, Bothwell, Mt. Brydges, Dutton and Newbury, which are supplied at 8.32 kV.

With of the exception of the city of Chatham, the city of St Thomas and parts of the town of Strathroy, the EPI distribution system is embedded within the HONI system meaning it is primarily served through HONI's distribution network rather than direct transmission station interconnection.

The Chatham-Kent area is supplied 27.6 kV by three HONI transmission stations: Kent TS, Leamington TS and Wallaceburg TS as well as a HONI distribution station Tilbury West DS. In addition, 8.32 kV is delivered to local communities by three HONI distribution stations supplied by Kent TS: Bothwell DS, Erieau DS, and Merlin DS.

Strathroy-Caradoc, Dutton, and Newbury receive power at 27.6 kV from three HONI transmission stations: Strathroy TS, Longwood TS, and Centralia TS. Low voltage distribution within these areas is further supported by Mt. Brydges DS and Wardsville DS, both of which are supplied by Longwood TS, as well as Dutton DS, which receives supply from Duart TS.

The city of St. Thomas is supplied by Edgeware TS, which provides 27.6 kV service through a series of express feeders that support the local distribution system.

List of Neighbouring Utilities:

EPI is bounded by HONI on all service territory boundaries.

1.7 Customer Engagement

1.7.1 Overview

As a regulated LDC, gathering feedback and responding to customer needs is one of EPI's top priorities and Customer and Community Focus is one of EPI's core values. In recent years, EPI has embraced new ways to connect with customers – through web- based services, surveys, and employing social media platforms such as X/Twitter, Facebook and Instagram. EPI uses the feedback from various customer engagement efforts to ensure it continues to deliver the value that customers expect and understand the needs and preferences of customers.

1.7.2 Ongoing Customer Engagement

EPI continuously engages with customers to understand their needs and preferences and respond to queries. To do so, EPI communicates with customers through a variety of channels, including inbound phone calls, interactive voice calls, live chat, customer service-related emails, website messaging and information, the My Account web portal, social media platforms (X/Twitter, Facebook, Instagram and LinkedIn), text alerts, bill inserts including rate brochures, on-bill messages, media releases, as well as booths at community events. This multichannel approach provides numerous opportunities for customer feedback, ensuring effective communication and engagement.

EPI also engages in community outreach efforts through the year such as participation in local events and initiatives. This includes providing electrical safety education in school classrooms and to first responders and community groups, supporting the St. Clair College Powerline Maintainer Program and organizing annual holiday meals in support of citizens in need.

Further, EPI engages in annual Customer Satisfaction Surveys (both "top down" surveys and ongoing transactional follow-up surveys), which include feedback from residential and small business customers. These surveys assist in identifying customer preferences and areas for improvement.

While EPI's customer satisfaction scores remain high (92% in 2024), EPI continuously strives to enhance its services based on customer feedback. In response to the ongoing feedback, EPI has incorporated the development of the digital channels listed above, as well as through the following recent and planned initiatives:

- Continued focus on monitoring of bill impacts and maintaining affordable distribution rates
- Customer Service training has been enhanced and delivered to include dementia-friendly communication techniques, empathy-based service approaches and reinforcement of core technical processes to support consistent and inclusive customer interactions.
- Ran SMS/Text Alert promotion in late 2024 which provided community support while increasing the penetration of this tool with customers. EPI has expanded the use of SMS messaging to provide enhanced customer notifications regarding planned outages, supporting more timely and accessible communication.
- In 2026, EPI will undertake a complete overhaul of its website. This initiative will improve how customers locate essential information, and include public safety, billing and self-service features. The redesign will integrate modernized technology to better support customer needs and expectations.
- In 2026, EPI will also launch a new customer mobile application. The application will enable users to access account information, view outages and report outages.
- Continue to enhance bill inserts, rate brochures and on-bill messages to assist with energy literacy.
- There is a high appetite for public electrical safety awareness education in grade schools, with first responders and with community groups. EPI will continue to assist with this education.
- Bi-weekly transactional survey responses are used by management to monitor customer sentiment and identify emerging service trends. This feedback loop supports targeted service

improvements and assists in identifying real-time training needs for newer Customer Service Representatives.

In addition, EPI completes a biennial Public Awareness of Electrical Safety Survey (“PAESS”) which assesses public knowledge of electrical safety. EPI achieved a 79% PAESS score in 2024, indicating a strong level of understanding of key electrical safety precautions within EPI’s service territory. EPI will continue to provide periodic public safety awareness campaigns going forward.

1.7.3 Application Specific Customer Engagement

Beyond the multiple other modes of ongoing customer interaction and engagement described above, EPI, along with its consultant Innovative Research Group (“IRG”), conducted multiple phases of Application-specific customer engagement to gather customers’ needs and preferences to incorporate into this Application. The full reports are included as Attachment 1-G.

Phase One was completed in the summer of 2024. This survey asked customers for feedback on their experience with EPI and about their needs and preferences, including reliability and other specific areas. See additional details below.

Phase Two was completed in the spring of 2025. This survey presented EPI’s overall draft plan informing this rate application and bill impacts and sought feedback on rate design, as well as additional detailed investment trade-off questions. See additional details below.

In addition, supplemental survey questions related to Canada-U.S. tariff impacts were sent to automotive and manufacturing sector Commercial & Industrial (“C&I”) customers in June and July 2025. See additional details below.

Phase One: Approach, Outcomes & Response

Phase One customer engagement was completed in August 2024. The survey asked customers for feedback on their experience with EPI and about their needs and preferences, including reliability and other specific areas. A key principle was the use of random-sampling research methods to ensure a representative sample of customers were engaged, ensuring the generalizability of the findings. A total of 1,733 Residential customers, 89 Small Business customers and 27 C&I customers participated in the survey. For Residential and Small Business customers, responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. Due to the size of the associated rate classes, C&I was not weighted.

The following table summarizes key outcomes and the EPI response:

Phase 1 Customer Engagement Key Outcomes (August 2024)	Phase 1 EPI Application Response
General • Most customers are satisfied with the services they receive from EPI • Customers prioritize delivering electricity at reasonable distribution rates, while also ensuring reliable service. The majority of customers also support necessary investments even if it has a direct impact on their bill • Most customers do not identify immediate service gaps, but when probed, are open to replacing aging infrastructure and making necessary investments. • Most customers expressed that they want EPI to invest what it takes to replace the system's aging infrastructure to maintain system reliability, proactively make investments in system capacity infrastructure to ensure customers in high growth areas do not experience a decline in reliability and invest in new technologies to improve reliability or provide other benefits.	• EPI will seek to balance reasonable and affordable rates while investing what it takes, including asset renewal and new technologies, to maintain current reliability levels and provide other benefits. • In combination with the feedback on Demand Response ("DR") programs (see below), EPI will pursue new supply in St. Thomas in 2025 to address existing constraints in that community
Tree & Vegetation Trimming • Many customers expressed support for investing in a vegetation management program that that invests in technology and uses satellite imaging to build a 3D model of EPI's service territory and lines to optimize vegetation trimming cycles and the scope of tree cutting	• EPI added this program to the draft investment plan and conducted further scoping on the satellite 3D vegetation model program and presented additional investment trade-off details to customers at Phase 2
Customer Mobile Application • Most customers expressed support for investing in a mobile application to review their account information, see outages and report outages	• EPI added this program to the draft investment plan and conducted further scoping on the customer mobile application program and presented additional investment trade-off details to customers at Phase 2
Demand Response Program	• EPI will not pursue a DR program

• The majority of customers expressed that they were not likely to enrol in a DR program, particularly industrial customers	• In combination with the General feedback (see above), EPI will pursue new supply in St. Thomas in 2025 to address existing constraints in that community
Electricity Usage • The majority of C&I and Large Use customers anticipate their planned electricity usage staying relatively the same • Although some C&I and Large Use customers have adopted, or have interest in pursuing EV fleets, EV charging or other renewable energy sources, overall interest from remaining customers was relatively low • Customer adoption of electric vehicles, self-generation and heat pumps in the EPI service territory is occurring and is at early stages[1]	• EPI will maintain a paced approach to changing customer electricity needs, such as the adoption of EVs and heat pumps, by planning and building the distribution system for reasonable forecasted load growth , focusing on asset renewal, and moving to a 100 kVA residential transformer standard • EPI will conduct further scoping and present investment trade-off details to customers on proactive transformer replacement at Phase 2

Phase Two: Approach, Outcomes & Response

Phase Two customer engagement was completed in April 2025. The survey presented the overall draft plan and bill impacts and sought feedback on rate harmonization and standby rates, as well as additional detailed investment trade-off questions. Again, random-sampling research methods were used to ensure a representative sample of customers were engaged, ensuring the generalizability of the findings. A total of 3,692 Residential customers, 114 Small Business customers and 39 C&I customers participated in the survey. For Residential and Small Business customers, responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. Due to the size of the associated rate classes, C&I was not weighted.

The following table summarizes key outcomes and the EPI response:

Phase 2 Customer Engagement Key Outcomes (April 2025)	Phase 2 EPI Application Response
Overall Draft Plan • The majority of customers support the overall draft plan presented in the survey	• EPI will continue to propose investing at the plan level (except for the proposed proactive

[1] This finding is from the April 2024 Public Awareness of Electrical Safety Survey with Innovative Research, which included questions to residents on energy transition. The August 2024 Phase 1 customer engagement feedback is relatively consistent with the results of the April 2024 Public Awareness survey, which showed the following existing DER adoption rates: EVs – approximately 8%, self-generation approximately 8% and heat pumps – approximately 14%. For remaining customers, there was a relatively low level of interest in pursuing EVs and heat pumps, and more interest in pursuing self-generation.

	replacement of the most at-risk transformers investment adjustment described below)
Targeted Reliability: investments to improve reliability for those experiencing poorer reliability than average • The majority of customers support investment at the draft plan level of investment, with the majority of those supporting the draft plan	• EPI will continue to propose targeted reliability investments at the plan level
Proactive Transformer Replacement: proactive transformer investments to support new uses and demand for electricity • The majority of customers support investing at the draft plan level or accelerating spending, with the majority of those supporting accelerating investment in the most at-risk proactive upgrades (rather than doubling the rate of proactive replacement)	• The initial draft plan included only reactive transformer upgrades • EPI will modify the proposed plan to propose investing an incremental $500k CAPEX per year on proactive replacement of the most at-risk transformers
Tree & Vegetation Trimming: incorporating satellite technology to better monitor the distribution system • Customers originally expressed support for this concept at Phase 1 and more details and bill impact / investment trade-off information was provided at Phase 2 • The majority of customers support investing at the draft plan level or accelerating investment, with the majority of those supporting the draft plan	• EPI will continue to propose investing for tree and vegetation management satellite technology at the draft plan level
Customer Mobile Application: launch of a mobile application to expand customer service offerings • Customers originally expressed support for this concept at Phase 1 and more details and bill impact / investment trade-off information was provided at Phase 2 • The majority of customers supported investing at the draft plan level	• EPI will continue to propose investing for the customer mobile application at the plan level
Rate Harmonization (of the current Legacy EPI and Legacy St. Thomas rate zones) • The majority of customers either supported rate harmonization, or did not like it but felt it was necessary	• EPI will continue to propose rate harmonization of the two legacy rate zones
Standby Rates Extension to St. Thomas (upon rate harmonization) • The majority of customers supported standby rate extension to St. Thomas, or did not like it but felt it was necessary	• EPI will continue to propose extension of standby rates to St. Thomas

Supplemental Canada-U.S. Trade and Tariff Survey: Approach, Outcomes & Response

In the spring and summer of 2025, EPI continued to review media reports[2] and receive anecdotal updates from automotive and manufacturing customers indicating operational uncertainty due to ongoing Canada-U.S. trade and tariff changes. As a result, some customers were understood to be considering actions that would result in a reduction of electricity demand.

To gather additional insight, EPI initiated a short supplemental survey through IRG, focused specifically on the impacts of Canada-U.S. tariff impacts. The survey was distributed directly by email to EPI's largest 39 automotive and manufacturing sector C&I customers, representing all such customers with an average 2025 monthly peak demand of 300 kW or more. The survey period ran from June 16, 2025 to July 8, 2025.

A total of eight (unweighted) customers responded to the survey, representing a response rate of 21%. The survey results indicated that respondents were experiencing uncertainty in their business operations. Respondents reported experiencing impacts such as higher production or material costs and adjustments to production levels or timing. Less than half of respondents reported supply chain disruptions or delays and other operational challenges. As a result, some customers had either undertaken (or were considering) mitigating actions such as delaying or reducing capital investments or re-evaluating locations or timelines. However, despite this, respondents indicated that their load had remained roughly stable, and a few customers indicated it might increase in the future.

The survey results present a dichotomy. On one hand, automotive and manufacturing customers are facing uncertainty related to ongoing Canada-U.S. trade and tariffs, and many appear to be responding to these challenges or considering potential mitigating actions. On the other hand, respondents indicated that their load is expected to remain stable, with some indicating it may increase in the future.

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[2] https://windsorstar.com/news/local-news/trade-war-fallout-auto-production-numbers-plummet-supply-chain-challenges-grow;
https://www.chathamdailynews.ca/news/local-news/chatham-kent-council-seeks-assessment-of-tariff-affected-sectors
https://windsorstar.com/news/local-news/study-finds-tariffs-stifling-sales-and-new-investment-in-canadian-auto-sector

EPI cannot explain this dichotomy. It is possible that customers may be reluctant to reveal potential future decreases in load; such reluctance could stem from a variety of confidential business reasons.

Prior to this survey, EPI intended to align the 2025 and 2026 forecast of the independent Manufacturing variable in its load forecast directly with a recent Financial Accountability Office of Ontario ("FAO") Report (which projects an 8% decrease in Manufacturing GDP by 2026 due to Canada-U.S. trade and tariffs). However, given the customer feedback received, EPI moderated its intended approach and applied an adjusted decrease of 4% to the Manufacturing variable, instead of the full 8% highlighted in the FAO Report. This adjustment results in a higher load forecast in the 2026 test year than was originally contemplated.

1.7.4 Customer Engagement with Customers affected by Cost of Service Proposals

EPI undertook Application-specific customer engagement (see Section 1.7.3) with customers who would be affected by the proposals in this Application, including rate harmonization. EPI also consulted with HONI regarding the elimination of the Embedded Distributor rate class; in 2021, HONI made system modifications and is no longer sub-embedded in EPI's service territory. As shown in Exhibit 7, Attachment 7-A, EPI provided HONI with a letter advising of the proposed Embedded Distributor rate class. HONI's email confirmation of its understanding is documented in Exhibit 7, Attachment 7-B.

1.7.5 Consultations with other parties

Consultations with the Transmitter (Hydro One)

EPI regularly consults with HONI transmission staff to share planning and operational information. These consultations can be initiated by either party and vary in format and timing.

Given the broad geographic region that EPI serves, it belongs to four IESO Integrated Regional Resource Planning ("IRRP") regional planning areas, for which HONI is the lead transmitter. As lead transmitter, HONI is primarily responsible for steering the regional planning in these regions. The statuses of the planning activity for each of these regions, along with the associated EPI communities, are described in the Table 1-14 below.

The regional planning process in Ontario is conducted across 21 regions and is prioritized into three groups: Group 1, Group 2, and Group 3. The priority assigned to each region is based on anticipated electricity system needs and may change over time as new and relevant information becomes available from LDCs.

TABLE 1-14: EPI REGIONAL PLANNING AREAS AND STATUSES

Region	Status	EPI Community
Windsor-Essex	Group 1 *(RIP[3] to be completed Oct. 2025)*	Wheatley, Tilbury
London Area	Group 2 *(Scoping Assessment completed April 2025; NA completed November 2024)*	Strathroy, Mt. Brydges, Dutton, Newbury, St. Thomas
Chatham/Lambton/Sarnia	Group 3 *(RIP completed Aug. 2022; Next cycle to begin in 2026)*	Blenheim, Bothwell, Chatham, Dresden, Erieau, Merlin, Ridgetown, Thamesville, Wallaceburg
Greater Bruce/Huron	Group 3 *(RIP completed Apr. 2025)*	Parkhill

IRRP– Integrated Regional Resource Planning: evaluates resource-based (e.g. DER/CDM) vs. wire solutions when energy needs require integrated coordination.

CONSULTATIONS WITH THE HOST AND EMBEDDED DISTRIBUTOR (HONI)

A significant portion of the EPI distribution system is embedded in HONI's distribution system. Accordingly, EPI regularly consults with HONI distribution staff on various operational matters.

[3] Regional Infrastructure Planning ("RIP") is the final planning step in addressing wire-infrastructure needs.

Consultations with Other Stakeholders

In August 2025, the OEB coordinated a meeting with EPI, OEB Staff and intervenors relating to this Application. At the meeting, EPI provided an overview of the evolution of Company and other Application matters.

1.7.6 Letters of Comment

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.

1.8 Performance Measurement

1.8.1 Scorecard and Performance Improvement Targets

Please refer to Attachment 1-D for the EPI 2024 Scorecard.

As shown in Attachment 1-D, in 2024 EPI met all Scorecard targets, with the exception of the SAIFI target. Results are discussed in further detail under each of the EPI Core Values areas below in this section.

The 2024 Scorecard is provided as Figure 4 and each measure is discussed below.

FIGURE 4: EPI 2024 SCORECARD

Scorecard - Entegrus Powerlines Inc. 8/12/2025

Performance Outcomes	Performance Categories	Measures		2020	2021	2022	2023	2024	Trend	Target Industry	Target Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		96.91%	97.60%	98.55%	97.48%	97.89%		90.00%	
		Scheduled Appointments Met On Time		99.83%	99.71%	100.00%	99.96%	99.96%		90.00%	
		Telephone Calls Answered On Time		79.11%	81.26%	68.42%	83.75%	76.56%		65.00%	
	Customer Satisfaction	First Contact Resolution		74	85	81	75	75			
		Billing Accuracy		99.81%	99.91%	99.91%	99.95%	99.90%		98.00%	
		Customer Satisfaction Survey Results		93	92	93	94	92			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		81.00%	78.00%	78.00%	79.00%	79.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	4	1	1	0	1			1
			Rate per 10, 100, 1000 km of line	1.297	0.329	0.311	0.000	0.306			0.384
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.47	1.09	1.76	1.31	1.26			1.42
		Average Number of Times that Power to a Customer is Interrupted [2]		1.18	1.02	1.18	0.93	1.48			1.01
	Asset Management	Distribution System Plan Implementation Progress		112.4	20.2	40.6	61.9	88.4			
	Cost Control	Efficiency Assessment		2	1	1	1	1			
		Total Cost per Customer [3]		$553	$558	$627	$713	$748			
		Total Cost per Km of Line [3]		$11,008	$10,670	$11,977	$13,731	$14,447			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.23	1.06	1.08	1.08	1.35			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.30	1.24	1.25	1.39	1.21			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.19%	9.19%	9.19%	9.19%	9.19%			
			Achieved	8.23%	9.29%	7.85%	8.79%	7.58%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met

Customer Focus

SERVICE QUALITY

EPI has consistently exceeded minimum targets established by the OEB for New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time and Telephone Calls Answered on Time.

New Residential/Small Business Services Connected On Time

In 2024, EPI connected 97.89% of low voltage residential and small business customers within the five-day timeline prescribed by the OEB. EPI's goal is to maintain the same level of service, surpassing the industry target of 90%.

Scheduled Appointments Met on Time

EPI scheduled 2,469 appointments in 2024 to complete work requested by customers (where customer presence is required). EPI met 99.96% of these appointments on time. EPI's goal is to maintain the same level of service, surpassing the industry target of 90%.

Telephone Calls Answered on Time

In 2024, EPI Customer Service received 54,585 calls from its customers – an average of over 215 calls per working day. In 76.56% of instances, EPI answered the call within 30 seconds or less. This result exceeds the OEB-mandated 65% target for timely call response. EPI staffs its Customer Service Call Centre to meet the 65% target, while balancing the need to prudently deploy resources in all areas of the business. EPI's goal is to continue to exceed the 65% OEB target.

CUSTOMER SATISFACTION

EPI continuously engages with customers to understand their needs and preferences and also respond to questions. EPI continues to maintain its strong First Contact Resolution results, consistently exceeds the Billing Accuracy prescribed OEB target of 98% and has strong Customer Satisfaction results year over year.

First Contact Resolution

EPI engages a third-party service provider to conduct ongoing First Contact Resolution ("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. However, FCR can be measured in a variety of ways and further regulatory guidance will be necessary in order to achieve meaningful, consistent and comparable information across electricity distributors. EPI believes that best practice is to measure FCR based on ongoing third-party surveys of a random sample of those customers who have recently contacted EPI. Accordingly, EPI's FCR is measured based on live agent transactional phone surveys conducted by a third-party service provider. To facilitate these surveys, throughout the year EPI provides the third-party service provider with a report of all customers who had contacted EPI Customer Service by telephone within the previous two weeks.

The third-party service provider's telephone agents, in turn, contact and survey EPI customers. Customers are asked to rate various facets of their customer experience and are also asked if their issue (i.e. their reason for calling) was resolved on their first contact to EPI. In 2024, the service provider's agents surveyed a random sample of 425 Residential and Small Business customers from February to October 2024. Of the 425 customers surveyed (the denominator), 317 customers (the numerator) indicated that their issue was resolved on the first call to EPI. This equates to the reported FCR result of 75%.

EPI continues to maintain its strong FCR results by implementing recommendations from the service provider. Accordingly, EPI has continued to engage the third-party service provider to assist with ongoing FCR measurement and customer service strategy improvements on specific issue types.

<u>Billing Accuracy</u>

In 2024, EPI issued 761,543 bills and achieved a billing accuracy of 99.90%. This compares favourably to the prescribed OEB target of 98%. EPI continues to monitor its billing accuracy results and processes to identify opportunities for improvement. It is EPI's goal to continue to exceed the Billing Accuracy OEB target of 98%.

<u>Customer Satisfaction Survey Results</u>

EPI engages a third-party service provider to conduct annual Customer Satisfaction surveys. In 2024, the third-party service provider conducted a random telephone survey for the period October 29, 2024 to October 31, 2024. A total of 505 customers were surveyed, however three customers did not respond. Of the remaining 502 customers who responded (the denominator), 461 customers (the numerator) rated their Overall Satisfaction in the top 3 boxes. This equates to the reported Customer Satisfaction result of 92%, which is comparable to previous years. Customer Satisfaction is a key area of focus for EPI. Accordingly, EPI will continue to measure Customer Satisfaction annually, as opposed to the regulatory requirement to measure it every other year.

OPERATIONAL EFFECTIVENESS

SAFETY

EPI believes that Employee Health and 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.

Level of Public Awareness

On a bi-annual basis, EPI engages a third-party service provider to conduct Public Safety Awareness surveys. The surveys are based upon a representative sample of each electrical distributor's service territory population and gauges awareness levels of key electrical safety concepts related to distribution assets. The surveys provide a benchmark of levels of awareness including identifying gaps where additional education and awareness efforts may be required. In accordance with OEB requirements, the surveys are conducted every other year. Accordingly, the survey results described below were completed for the 2023 scorecard and are also applicable to the 2024 scorecard. EPI conducted a public safety awareness campaign in Q1 of 2024 utilizing local media and digital website content. Further, EPI continues to assist and participate in community safety events. EPI engaged a third-party service provider to conduct stratified random telephone surveys of 603 Ontario residents, ages 18 or older, currently residing in the EPI service territory during the period from March 6, 2024 and March 18, 2024. The survey asked residents electrical safety questions and then an overall index score was calculated in accordance with a prescribed algorithm. Public Awareness of Electrical Safety results for 2023/2024 showed a slight increase compared to the prior results at 79%.

Level of Compliance with Ontario Regulation 22/04

Ontario Regulation 22/04 (Electrical Distribution Safety) establishes objective-based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. The regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service. EPI is audited annually for compliance and was found to be compliant in 2024. EPI's goal is to continue to be compliant with O. Reg 22/04.

Serious Electrical Incident Index

This is measured as the number of non-occupational (general public) serious electrical incidents occurring on EPI' distribution system and reported to the ESA, expressed as a raw number and as the number per 1,000 km of line. EPI had one incident in 2024. The incident involved animal contact with an overhead line that caused the line to fall to the ground; there were no injuries to the public. In accordance with its foremost core value of Safety, EPI' staff examine the circumstances surrounding such incidents and incorporate insights into the content of relevant employee safety training and public safety awareness programs.

SYSTEM RELIABILITY

EPI continues to view reliability of electricity service as a high priority. The Average Number of Hours that Power to a Customer is Interrupted (SAIDI) and Average Number of Times that Power to a Customer is Interrupted (SAIFI) are measures that the OEB establishes baseline targets calculated as the average of EPI's performance for the period 2016 – 2020.

Average Number of Hours that Power to a Customer is Interrupted ("SAIDI")

For this measure, the OEB establishes baseline targets based on the average of the distributor's performance for the period 2016 –2020 (the baseline period is updated every 5 years). EPI's 2024 result of 1.26 is favourable to prior year results and is also better than the target of 1.42. In March 2023, the OEB standardized the methodology by which distributors report Major Event Day ("MED") weather events (which are excluded from these statistics). In 2024, EPI had one weather event meet the MED threshold, which contributed to the favourable result versus target. Further, starting in 2020, EPI has intensified its efforts on system renewal, which should contribute to a reduction in outages that would otherwise occur. EPI continues to focus on the installation of smart grid equipment, which should contribute to a reduction in the duration and frequency of outages. EPI continues to view reliability of electricity service as a high priority.

Average Number of Times that Power to a Customer is Interrupted ("SAIFI")

For this measure, the OEB establishes baseline targets calculated as the average of the distributor's performance for the period 2016 – 2020 (the baseline period is updated every 5 years). EPI's 2024 result of 1.48 is above the target of 1.01. EPI did not meet its SAIFI target in 2024, mainly due to aging infrastructure and adverse weather below the Major Event Day threshold. In 2024, foreign interference also added to the outages. Investments in smart grid technology and asset renewal are helping but benefits are gradual, and results still fluctuate with storm frequency and severity. EPI continues to view reliability of electricity service as a high priority.

ASSET MANAGEMENT

Distribution System Plan Implementation Progress

EPI maintains a DSP that adopts a proactive, balanced approach to distribution system planning, infrastructure investment and replacement programs to address immediate risks associated with end-of-life assets; manage distribution system risks; ensure the safe and reliable delivery of electricity; and balance ratepayer and utility affordability. In 2021, EPI filed a combined and comprehensive 2021-2025 DSP, inclusive of both the Entegrus-Main and Entegrus-St. Thomas rate zones.
EPI made substantial progress on its DSP implementation in 2024. The 2024 result indicates that EPI has completed 88.4% of its planned projected spend in its five-year plan.

EPI has prepared a 2026-2030 DSP for filing with this Application and targets to continue to measure progress against that plan annually, with the goal of meeting the requirements of the plan and achieving the desired outcomes based on system and customer needs.

COST CONTROL

EPI strives to achieve greater efficiency through productivity improvements and cost control without compromising safety and reliability. EPI is currently in Group 1 of the Pacific Economics Group ("PEG") efficiency ranking.

Efficiency Assessment

The total costs for Ontario local electricity distribution companies are evaluated based on econometric modeling conducted by a consultant (PEG) on behalf of the OEB to produce a single efficiency ranking. The 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. In 2024, EPI's actual costs for 2022-2024 were 27.8% lower than the costs predicted by the OEB's consultant. For the fourth consecutive year, EPI was placed in Group 1, where a Group 1 distributor is defined as having actual costs which are at least 25% lower than the costs predicted for the distributor. Group 1 is considered "most efficient". In 2024, EPI ranked 16th out of 54 distributors in terms of cost performance results versus benchmark.

Total Cost per Customer

Total cost per customer is calculated as the sum of EPI' capital and operating costs (including certain adjustments to make the costs more comparable between distributors), divided by the total number of customers that EPI serves. EPI's cost performance result for 2024 is $748 per customer.

Total Cost per Km of Line

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that EPI operates to serve its customers, which equates to $14,447 per kilometer of line.

PUBLIC POLICY RESPONSIVENESS

CONNECTION OF RENEWABLE GENERATION

New Micro-embedded Generation Facilities Connected on Time

Electricity distributors are required to connect an applicant's micro-embedded generation facility (i.e. MicroFIT projects of less than 10kW or net metering projects) 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 minimum acceptable performance level for this measure is 90%. In 2024, EPI connected the 19 new micro-embedded generation facility requests received within the prescribed time frame of five business days. EPI works closely with its customers and their contractors to address any connection issues to ensure the project is connected on time.

EPI has maintained 100% of new micro-embedded generation facilities connected on time. EPI will continue to provide the staff resources to maintain an efficient and effective methodology to connect new micro-embedded generation facilities.

FINANCIAL PERFORMANCE

FINANCIAL RATIOS

EPI has maintained solid liquidity, leverage and profitability ratios.

Liquidity: Current Ratio

Liquidity is calculated by dividing Current Assets by Current Liabilities. This ratio is also known as Working Capital Ratio and measures an entity's ability to pay short-term financial obligations. As an indicator of financial health, a Liquidity Ratio of greater than 1 is considered good, as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations. The EPI current ratio was 1.35 in 2024. EPI's goal is to maintain a Liquidity Ratio of more than 1.00. As noted above, this means that the organization has resources available in the short term to meet its short-term financial obligations.

Leverage: Total Debt to Equity Ratio

The OEB uses a deemed capital structure of 60% debt, 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 levered than the deemed capital structure. A high debt to equity ratio may indicate 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. As demonstrated by its 2024 Leverage Ratio of 1.21, EPI continues to maintain a debt-to-equity structure that closely approximates the deemed 60% to 40% capital mix as set out by the OEB. EPI's strong financial position is further supported by its recent Standard & Poor's Rating Services rating of "A".

Profitability: Regulatory Return on Equity

The table below shows the deemed and achieved Return on Equity.

TABLE 1-15: HISTORICAL ROE

Row	Performance Year	Utility	Profitability: Regulatory Return on Equity - Deemed	Profitability: Regulatory Return on Equity - Actual
1	2015	Former STEI	9.30%	11.64%
2	2016	EPI	9.19%	7.46%
3	2016	Former STEI	9.30%	10.65%
4	2017	EPI	9.19%	7.64%
5	2017	Former STEI	9.30%	11.60%
6	2018	EPI	9.19%	8.20%
7	2019	EPI	9.19%	10.58%
8	2020	EPI	9.19%	8.23%
9	2021	EPI	9.19%	9.29%
10	2022	EPI	9.19%	7.85%
11	2023	EPI	9.19%	8.79%
12	2024	EPI	9.19%	7.58%

1.8.2 PEG MODEL

The OEB conducts an annual efficiency assessment of Ontario distributors, 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.

As described in Section 1.3.1, EPI's costs are increasingly driven by the need to provide modern, reliable service to growing communities and to adapt to evolving industry requirements, including the deployment of new technologies, while ensuring that service quality metrics are met or exceeded. Despite these pressures – such as persistent inflation, the need to renew aging infrastructure and heighted legislative and regulatory requirements – EPI's total costs have remained significantly below those predicted by the OEB consultant's econometric model.

As a result, since 2021, EPI has been ranked in the first Total Cost Benchmarking efficiency cohort, representing the strongest category of cost efficiency across Ontario distributors. EPI forecasts that its Cohort 1 cost performance will continue in the 2026 Test Year. This achievement signals EPI's success in prudently managing its operations in an increasingly complex operating environment. EPI's ability to remain in Cohort 1 underscores its discipline in balancing costs pressures while delivering safe, reliable and affordable service.

EPI's historical cost performance and efficiency assessment performance from 2016 to 2023 is shown in Table 1-16, and EPI's forecast of its 2024 to 2026 test year performance is shown in Table 1-17.

TABLE 1-16: HISTORICAL EFFICIENCY ASSESSMENT PERFORMANCE

Description	2016 Actuals	2016 Actuals	2017 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals
	Legacy EPI	STEI	Legacy EPI	STEI	EPI	EPI	EPI	EPI	EPI	EPI
Percentage Difference (Cost Performance)	-15.7%	-7.7%	-17.5%	-14.8%	-16.0%	-21.0%	-25.4%	-28.7%	-26.9%	-27.8%
Three-Year Average Performance	-16.6%	-8.1%	-16.9%	-10.9%	-15.4%	-17.9%	-20.8%	-25.0%	-27.0%	-25.7%
Stretch Factor Cohort - Annual (Three Year Average)	2	3	2	2	2	2	2	1	1	1
Rate Year	2018	2018	2019	2019	2020	2021	2022	2023	2024	2025

TABLE 1-17: EPI FORECAST EFFICIENCY ASSESSMENT PERFORMANCE

Description	2024 Actuals	2025 Bridge Year	2026 Test Year
Actual Total Cost	$ 47,502,148	$ 51,132,861	$ 53,818,377
Predicted Total Cost	$ 63,245,435	$ 68,233,171	$ 71,695,108
Actual Cost Greater Than/(Less Than) Predicted Cost	$ (15,743,287)	$ (17,100,310)	$ (17,876,731)
Percentage Difference (Cost Performance)	**-28.6%**	**-28.9%**	**-28.7%**
Three-Year Average Performance	-27.8%	-28.4%	-28.7%
Stretch Factor Cohort - Annual	1	1	1
Stretch Factor Cohort - Annual (Three Year Average)	1	1	1

Details of the calculations underpinning the results shown in Table 1-17 above are included with this Application as a standalone excel document (EPI_2024_Benchmarking_Spreadsheet_Forecast_Model_20250829).

1.8.3 OEB-APPROVED IRM INCREASES AND ASSIGNED COHORT

Table 1-18 below shows the respective OEB-approved IRM increases for each of the historical years since the last rebasing, along with the assigned cohort as per the PEG model.

TABLE 1-18: OEB APPROVED IRM INCREASES

	Legacy Entegrus	Legacy STT	Combined EPI	Legacy Entegrus Cohort	Legacy STT Cohort	Combined EPI
2016	1.95%	1.80%		2	3	
2017	1.75%	1.60%		2	2	
2018			1.05%			2
2019			1.35%			2
2020			1.85%			2
2021			2.05%			1
2022			3.15%			1
2023			3.70%			1
2024			4.80%			1
2025			3.60%			1

1.8.4 ACTIVITY AND PERFORMANCE-BASED BENCHMARKING ("APB")

APB RESULTS AND VARIANCE ANALYSIS FOR 2019 - 2023

The OEB announced changes to the APB framework in line with its commitment to encourage continuous improvement by regulated utilities and increase regulatory efficiency.

On October 17, 2024, the OEB published its APB reports with unit cost results for ten programs for results up to 2023. EPI provides its unit cost variance analysis for each of the ten programs below.

BILLING O&M

EPI's billing O&M costs are 42.7% lower than the 2019-2023 industry average as identified in Table 1-19 below. EPI cannot comment on why its billing O&M costs are significantly lower than the industry average without visibility into what costs other LDCs are recording in Account 5315.

TABLE 1-19: BILLING O&M COST PER CUSTOMER

Billing O&M Cost ($) per Customer	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$ 18.57	$ 18.87	$ 22.34	$ 22.76	$ 21.85	$ 20.88
Industry						$ 36.41
vs. Industry Average						-42.7%

METERING O&M

EPI's metering O&M costs are 63.3% lower than the 2019-2023 industry average as identified in Table 1-20 below. EPI cannot comment on why its metering costs are significantly lower than the industry average without visibility into what costs other LDCs are recording in this Program.

TABLE 1-20: METERING O&M COST PER CUSTOMER

Metering O&M Cost ($) per Customer	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$ 6.51	$ 7.79	$ 7.12	$ 6.19	$ 8.07	$ 7.14
Industry						$ 19.43
vs. Industry Average						-63.3%

VEGETATION MANAGEMENT O&M

EPI's vegetation management O&M costs are 63.2% lower than the 2019-2023 industry average as identified in Table 1-21 below. EPI cannot comment on why its vegetation management O&M costs are significantly lower than the industry average without visibility into what costs other LDCs are recording in this Program.

TABLE 1-21: VEGETATION MANAGEMENT O&M COST PER POLE

Vegetation Management O&M Cost ($) per Pole	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$ 13.09	$ 5.61	$ 9.51	$ 22.03	$ 21.14	$ 14.28
Industry						$ 38.76
vs. Industry Average						-63.2%

LINES O&M

EPI's lines O&M costs are within 0.4% of the 2019-2023 industry average as identified in Table 1-22 below. EPI's lines O&M costs are very consistent with the industry average.

TABLE 1-22: LINES O&M COST PER CIRCUIT KM OF PRIMARY LINE

Lines O&M Cost ($) per cct km of Primary Line	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$ 1,690.33	$ 1,748.56	$ 1,921.09	$ 1,959.31	$ 1,965.09	$ 1,856.88
Industry						$ 1,849.13
vs. Industry Average						0.4%

STATIONS O&M

EPI serves 17 communities and as of 2019, had 21 substations, which is a function of the history and evolution of EPI and is further discussed in Section 1.6.2. Accordingly, EPI's stations O&M costs are 157.8% higher than the 2019-2023 industry average as identified in Table 1-23 below. As per the Chapter 2 filing requirements, since EPI is greater than 25% higher than the industry five-year average, EPI requires a plan to drive down unit costs. As EPI continues to decommission substations, EPI's Stations O&M costs are expected to normalize toward the industry average. Please refer to Exhibit 2, Attachment 2-C (DSP), Section 3.1.2.2 and Attachment J (Material Investment Narratives – Voltage Conversion).

TABLE 1-23: STATIONS O&M COST PER TOTAL MVA

Stations O&M Cost ($) per Total MVA	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$3,246.07	$2,768.51	$2,988.93	$3,601.75	$3,797.45	$3,280.54
Industry						$1,272.31
vs. Industry Average						157.8%

POLES, TOWERS AND FIXTURES O&M

EPI's poles, towers and fixtures O&M costs are 35.8% lower than the 2019-2023 industry average as identified in Table 1-24 below. EPI cannot comment on why its poles, towers and fixtures O&M costs are significantly lower than the industry average without visibility into what costs other LDCs are recording in this Program.

TABLE 1-24: POLES, TOWERS, FIXTURES O&M COST ($) PER POLE

Poles, Towers, Fixtures O&M Cost ($) per Pole	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$ 7.36	$ 5.18	$ 5.77	$ 8.03	$ 9.29	$ 7.12
Industry						$ 11.10
vs. Industry Average						-35.8%

STATIONS CAPEX

EPI's station capital expenditures are 74.6% lower than the 2019-2023 industry average as identified in Table 1-25 below. As discussed in Exhibit 2, Attachment 2-C (DSP), Section 3.1.2.2, EPI maintains a significant ongoing voltage conversion program, which decommissions legacy low voltage substations and seeks to avoid station rebuild CAPEX. Accordingly, EPI focuses on maintaining active substations (incurring O&M expense) until their conversion, which results in EPI's stations CAPEX being lower than average and stations O&M being higher than average.

TABLE 1-25: STATIONS CAPEX COST PER TOTAL MVA

Stations Capex Cost ($) per Total MVA	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$1,495.94	$1,216.72	$2,072.14	$738.33	$334.38	$1,171.50
Industry						$4,616.40
vs. Industry Average						-74.6%

POLES, TOWERS, FIXTURES CAPEX

EPI's poles, towers and fixtures capital expenditures are 17.2% lower than the 2019-2023 industry average as identified in Table 1-26 below. EPI cannot comment on why its poles, towers and fixtures capital expenditures are significantly lower than the industry average without visibility into what costs other LDCs are recording in this Program.

TABLE 1-26: POLES, TOWERS AND FIXTURES CAPEX COST PER POLE

Poles, Towers and Fixtures Capex Cost ($) per Pole	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$8,515.41	$10,448.61	$7,762.80	$8,510.63	$8,363.70	$ 8,720.23
Industry						$10,532.63
vs. Industry Average						-17.2%

LINE TRANSFORMER CAPEX

EPI's line transformer capital expenditures are 26.3% lower than the 2019-2023 industry average as identified in Table 1-27 below. EPI cannot comment on why its line transformer capital expenditures are lower than the industry average without visibility into what costs other LDCs are recording in this Program.

TABLE 1-27: LINE TRANSFORMER CAPEX COST PER TRANSFORMER

Line Transformer Capex Cost ($) per Transformer	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$8,251.61	$7,212.40	$10,268.72	$7,422.22	$12,118.56	$ 9,054.70
Industry						$12,286.64
vs. Industry Average						-26.3%

METERS CAPEX

EPI's meter capital expenditures are 107% higher than the 2019-2023 industry average as identified in Table 1-28 below. As per the Chapter 2 filing requirements, since EPI is greater than 25% higher than the industry five-year average, EPI requires a plan to drive down unit costs. As an approved early adopter of smart meters, EPI installed the majority of its Residential smart meter fleet in 2006-2007. Due to this early adoption, it is therefore probable that EPI's meters are being life cycled (replaced) comparatively sooner than typical industry experience. Accordingly, it is anticipated that EPI's meter capital expenditures will begin to decline in the latter part of the forecast period as the rest of the industry experiences an increase related to its similar ramp up of life-cycling. EPI will focus on completing life cycling and will continually seek opportunities to drive down costs through collaborative procurement. Please refer to Exhibit 2, Attachment 2-C (DSP), Section 3.1.2.2 and Attachment J (Material Investment Narratives - Metering Renewal).

TABLE 1-28: METERS CAPEX COST PER CUSTOMER

Meters Capex Cost ($) per Customer	2019	2020	2021	2022	2023	Average 2019-2023
Entegrus Powerlines	$ 22.21	$ 22.29	$ 24.68	$ 28.63	$ 28.64	$ 25.29
Industry						$ 12.22
vs. Industry Average						107.0%

FORECAST APB RESULTS 2024-2026

EPI aims to maintain and improve its strong performance on APB performance metrics, ranking better than the industry average where feasible to demonstrate operational efficiency and fiscal responsibility. Table 1-29 below provides actual APB results for 2024 and forecast results for 2025 and 2026.

TABLE 1-29: ACTUAL 2024 AND FORECAST 2025-2026 APB RESULTS

	2024	2025	2026
1. Billing O&M	20.89	24.78	27.34
2. Metering O&M	9.72	10.28	10.90
3. Vegetation Management O&M	19.89	17.42	23.06
4. Lines O&M	1,809.69	2,273.40	2,432.41
5. Stations O&M	5,312.83	5,921.73	4,719.78
6. Poles, Towers O&M	10.29	10.98	11.78
7. Stations CAPEX	656.59	2,017.35	1,287.60
8. Poles, Towers CAPEX	8,029.46	8,959.57	11,471.53
9. Line Transformers CAPEX	17,666.40	17,207.18	18,265.20
10. Meters CAPEX	45.29	39.76	46.99

EPI will continue to identify and implement efficiencies to drive down unit costs for results on the metrics that were 20% more than the previous year or five-year average, or more than 25% higher than the industry average.

1.9 FACILITATING INNOVATION

EPI focuses on the deployment of new and advanced processes and technologies that reflect its core values of Safety, Inspired & Empowered People, Operational Excellence, Customer & Community Focus and Sustainable Growth. These innovations are designed to address the evolving needs of customers, strengthen system resilience, and support the continued modernization of operations.

The examples below illustrate how EPI’s commitment to practical, forward-looking solutions has shaped ongoing operations and this Application.

1.9.1 TRANSFORMATIONAL INNOVATION

EPI's approach to transformational innovation reflects its commitment to Safety, Operational Excellence, Customer & Community Focus and Inspired & Empowered People through practical solutions that address the evolving needs of its customers and the distribution system. The following initiatives demonstrate how EPI is applying modern tools and technology to deliver value, managing emerging system risks and enhancing the customer experience.

- **Protection and Control Validation / Testing Lab:** EPI has recently established a small, dedicated Protection and Control Validation / Testing Lab by repurposing a former cash vault at its Chatham office; this provides a secure, controlled environment for the testing and optimization of protection and control (P&C) systems. A key feature of the lab is a physical Protection Relay Test System ("PRTS"), which enables engineering, metering, and operations staff to validate, adjust, and fine-tune the settings of smart switches, reclosers, fault indicators, and relay controllers prior to field deployment (see additional details under "Sectionalization and Distribution Automation" below). The PRTS allows for the injection of simulated signals – including actual field waveform data and generated fault conditions – supporting comprehensive evaluation of device configurations under realistic operating scenarios. This testing process helps identify and correct potential misconfigurations, ensuring that P&C schemes are optimized for reliability, safety, and performance. The lab also serves as a hands-on training and development platform, empowering employees to build expertise in complex protection coordination and automation schemes within a safe, controlled setting.

- **Satellite-Based Vegetation Management Program:** EPI is seeking approval through this Application to enhance its vegetation management through satellite-based vegetation management, which was supported by customers in customer engagement. Serving 17 communities with thousands of trees in proximity to its distribution system, EPI must regularly ensure that vegetation remains clear of electrical equipment to maintain safety and reliability. On a multi-year cycle, EPI conducts community-by-community trimming, with tree-related contacts typically accounting for 7–19% of all customer outages annually. The satellite-based solution will generate detailed vegetation models, enabling more precise planning to minimize unnecessary trimming while targeting areas of highest risk. This innovation is expected to reduce outages from tree contacts and improve efficiency in supporting major infrastructure projects by identifying potential conflicts earlier. Further details are provided in Exhibit 2, Attachment 2-C (DSP), Section 3.2.1.2.1.

- **AI-Enabled Load Pattern Detection and Proactive Transformer Renewal:** EPI is seeking approval through this Application to support proactive transformer replacement. Identification of at-risk transformers for proactive replacement is enabled by AI-driven EV 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. Many transformers in the EPI service territory were not originally designed to accommodate these evolving load patterns, particularly the simultaneous charging of multiple EVs, and are now at higher risk of overloading and failure. Adoption of these technologies does not occur uniformly across the territory, making targeted investment critical. This approach aligns with customer engagement feedback that endorsed investments in proactive transformer replacement to address emerging system risks. To proactively identify the transformers most at risk, the EPI Data Scientist reviewed academic journals and research to identify multiple applicable AI models and trained these using EPI smart meter data to determine the most effective approach. The recommendations generated by the AI tool are provided to engineering staff, who review and validate the outputs to ensure alignment with system realities. This innovative solution delivers actionable insights for targeted asset renewal. Further details are provided in Exhibit 2, Attachment 2-C (DSP) Section 5.1.2.3.3.

- **Sectionalization and Distribution Automation**: EPI serves 17 communities through a combination of transmission-connected and embedded (distribution-connected) supply. To enhance service reliability across this diverse network, EPI has increased 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 – an important benefit given the size of EPI's service territory and the associated outage response logistics. Since 2017, EPI has implemented distribution automation, including the installation of smart switches in

Wallaceburg, Tilbury, Blenheim, Ridgetown, and Chatham. These automation schemes have collectively helped avoid an estimated 124,500 Customer Hours of Interruption (CHI) to date by mitigating the impact of outages caused by upstream faults, defective equipment, vegetation contact, and foreign interference (e.g., vehicular collisions). In addition to improving reliability for customers, feeder automation supports operational savings by minimizing outage response costs, such as truck rolls and overtime. Further details are provided in Exhibit 2, Attachment 2-C (DSP), Section 5.1.2.3.1.

In addition, EPI evaluates and considers the suitability of NWAs through a structured screening process, in accordance with the OEB's Benefit-Costs Analysis ("BCA") framework. This includes conducting a cost-benefit analysis to defer or avoid traditional wired infrastructure investments, where applicable.

1.9.2 Process and Operational Improvement

EPI's efforts to enhance internal processes are grounded in practical improvements through automation and digitization, reflecting its commitment to Safety, Operational Excellence, Sustainable Growth, and Inspired & Empowered People. The following initiatives demonstrate how EPI is leveraging digital tools to modernize processes, enhance service delivery, and support the evolving needs of its workforce and community.

- **Electronic Funds Transfer ("EFT") Implementation:** EPI successfully implemented EFT for vendor payments, modernizing its accounts payable processes. By moving from paper-based payments to a fully digital approach, EPI has enabled consistent and secure payments while strengthening financial controls. This initiative helps minimize the risk of fraud, lowers EPI's environmental footprint, and eliminates the need for physical cheque handling, making it easier to support remote operations when needed, while maintaining strong, reliable vendor relationships through timely payments.

- **Integrated Enterprise Resource Planning ("ERP") and Human Resources Information System ("HRIS") Platforms:** To advance enterprise-wide integration and modernization, EPI launched Microsoft Dynamics 365 Business Central as the core ERP system in 2024. This cloud-based solution enhances financial management, procurement, and operational workflows, providing real-time insights and supporting decision-making across the organization. Complementing this, Dayforce was deployed as EPI's HRIS and payroll platform, enabling centralized workforce management, ensuring compliance, and supporting scalability through more automated HR and payroll processes.

- **Health and Safety Management System (BIS Safety):** EPI has implemented BIS Safety, a cloud-based Health and Safety Management System that streamlines training, compliance tracking, safety documentation, and key safety workflows such as inspections and incident reporting. The system centralizes employee records, monitors certifications, and ensures compliance requirements are met, while managing online, classroom, and on-the-job training from a single platform. It also provides access to a library of industry-recognized safety courses and automated reminders for expiring certifications and upcoming training, helping to improve coordination of administrative activities. The BIS Safety mobile app extends these capabilities by providing employees, including those working in the field, with easy access to their training records, certificates, forms, policies, and safety resources whenever needed.

1.10 Financial Information

1.10.1 Audited Financial Statements

Copies of EPI's 2024 Audited Financial Statements are provided in Attachment 1-H.

1.10.2 Reconciliation of Financial Statements

A detailed reconciliation between the Audited Financial Statements and the 2024 RRR trial balance is attached as Attachment 1-I.

1.10.3 Annual Report and Management Discussion and Analysis

Neither EPI, nor its parent company, EPI Inc., issues an Annual Report.

1.10.4 Rating Agency Report

The April 30, 2025, Standard & Poor's rating agency report on EPI accompanies this application as Attachment 1-J.

1.10.5 Prospectuses or Information Circulars

EPI has no past or planned prospectuses, information circulars, or other similar documents.

1.10.6 Changes in Tax Status

EPI is a corporation incorporated pursuant to the Ontario *Business Corporations Act* and has not had a change in tax status since its last COS Application.

1.10.7 Accounting Orders

EPI has not departed from the Accounting Procedures Handbook ("APH"). In its 2016 COS (EB-2015-0061), EPI established Account 1508 – Sub-Account – OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account. The purpose of this account is to record the difference in revenue requirement each year, effective May 1, 2016, between both the capitalized and OM&A components of OPEBs accounted for using a forecasted cash basis (as reflected in rates) and the capitalized and OM&A components of OPEBs accounted for using a forecasted accrual basis. The Accounting Order approved in EB-2015-0061 is included in Exhibit 9 as Attachment 9-A. As part of this Application, EPI is proposing to discontinue the use of this sub-account and transition to the OEB's generic Account 1522 for balances beginning May 1, 2026.

EPI has no further existing or proposed accounting orders.

1.10.8 Departures from the Uniform System of Accounts ("USoA")

EPI has applied the accounting principles and used the categories of accounts in the OEB's APH and USoA in the preparation of this Application. EPI confirms there are no departures from the USoA.

1.10.9 Accounting Standard Used

In accordance with the Filing Requirements, EPI adopted International Financial Reporting Standards ("IFRS") on January 1, 2015. EPI has provided the 2016 to 2024 accounting information under MIFRS. The 2025 Bridge Year and 2026 Test Year budgets have also been provided based on MIFRS.

1.10.10 Non-Utility Business Accounting

EPI confirms that accounting for its non-utility activities was segregated from its rate regulated activities in accordance with the OEB's Guidelines: Regulation and Accounting Treatments for Distributor-Owned Generation Facilities G-2009-0300 dated September 15, 2009.

1.11 Distributor Consolidation

1.11.1 Overview

EPI 2018 MERGER WITH ST. THOMAS ENERGY

On March 15, 2018, the OEB approved the amalgamation of Legacy EPI and STEI in MAADs application EB-2017-0212. Thereafter, EPI notified the OEB that the amalgamation was completed on April 1, 2018. The amalgamated company continued as EPI.

At the time of the amalgamation, Legacy EPI had approximately 41,000 customers across 16 Southwestern Ontario communities. The former STEI had approximately 17,000 customers in St. Thomas, Ontario. Following the transaction's closing, EPI had approximately 58,000 customers and integration of the operations of the two organizations began.

INVESTIGATION OF POTENTIAL OPPORTUNITIES FOR CONSOLIDATION AND COLLABORATION WITH OTHER UTILITIES

As described in Section 1.5, EPI currently serves 17 communities and is the product of successive consolidations involving 11 former Municipal Electric Utilities and four former Local Distribution Companies (“LDCs”), including STEI. This historical evolution demonstrates that EPI has consistently embraced consolidation and partnership as a core component of its strategic approach.

In alignment with this strategic orientation, EPI continually assesses potential opportunities for consolidation, collaboration or partnerships with other distributors.

From March 13, 2023, to December 20, 2024, EPI Inc. provided contracted management services to E.L.K. Energy Inc. (“E.L.K.”). The arrangement was described in the following Windsor Star article of March 13, 2023: https://windsorstar.com/news/local-news/EPI-takes-over-management-of-e-l-k-energy.

On March 14, 2025, the Town of Essex, the sole shareholder of E.L.K. Energy, announced that it had agreed to sell all shares of E.L.K. to the ENWIN Group of Companies. The announcement was posted on the Town of Essex website on March 14, 2025: https://www.essex.ca/en/news/town-of-essex-announces-sale-of-e-l-k-energy-inc-shares-to-enwin.aspx.

EPI will continue to monitor and assess opportunities for collaboration or consolidation that are aligned with its strategic priorities and that would benefit its customers, provide efficiencies or enhance service delivery.

ADDITIONAL COLLABORATION WITH OTHER UTILITIES

EPI collaborates with other utilities through various industry associations and co-operatives, including the following:

- **Utility Standards Forum ("USF"):** A forum of Ontario electricity distributors focused on collaboration, mutual support, and industry representation. This includes the establishment of common build standards and best practices.
- **Grid Smart City ("GSC"):** A consortium of LDC and non-LDC partners, collaborating to advance smart grid technologies and energy solutions. In addition to best practice sharing and other initiatives, facilitates purchasing consortium bulk purchases of standard equipment (ie. transformers, poles, IT cyber security solutions) which allows for lower unit costs and shorter lead times.
- **Ontario Mutual Aid Group ("OnMAG"):** A collaborative group of utilities focused on storm response, mutual aid, and enhancing emergency preparedness, including coordination of resources and mutual response to outages and damages arising from adverse weather.
- **Electrical Distributors Association ("EDA"):** The industry association advocating for LDCs, providing policy support, resources, and sector collaboration opportunities. The EDA hosts discussions and coordinates thought leadership about emerging industry issues, regulations, and

standards, acting as a centralized intermediary for submitting feedback to the Ministry of Energy and OEB.

1.11.2 Incentives that Formed Part of Acquisition

As detailed in the EPI/STEI MAADs (merger) application (EB-2017-0212), the transaction was a non-cash amalgamation, involving only the transfer of shares. A third-party valuation was completed post-amalgamation, which resulted in the following EPI ownership allocations (held through EPI's holding company, Entegrus Inc.):

- The Corporation of the Municipality of Chatham-Kent: (71.49%)
- The Corporation of the City of St. Thomas: (20.57%)
- Corix Infrastructure Inc.: (7.94%).

EPI is not proposing any incentive or merger costs that will form part of the Rate Base, and/or revenue requirement.

1.11.3 Commitments Made to Shareholders

As detailed in the EPI/STEI MAADs (merger) application (EB-2017-0212), shareholders were not offered any other commitments and there were no amounts sought to be funded through rates. In the MAADs Decision, the OEB approved the eight-year rebasing deferral period proposed by the applicants. Dividends to the shareholders since the merger have been inclusive of merger costs incurred and savings generated. Upon rebasing, customers will benefit from a lower rate structure that would have otherwise occurred had the merger not taken place.

1.11.4 Projected And Realized Savings as a Result of Consolidation Compared to MAADs Application

Projected Net Savings

Projected ongoing cost savings from 2017 to 2025 from the EPI/STEI merger were included in EPI/STEI MAADs (merger) application (EB-2017-0212) at Attachment M, totaling $12.0M (inclusive of both capital and expense cost savings). The synergies were projected to result largely from administrative cost reductions, the consolidation of IT, regulatory and finance functions and the in-housing of billing. A subtotal of 2017-2025 has been added below, showing projected transition costs from 2017-2025 of $2.1M, resulting in projected net savings of $9.9M:

TABLE 1-30: EB-2017-0212 MAADS PROJECTED NET SAVINGS FROM EPI/STEI MERGER

Line No.	Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	Subtotal	2026	2027	2028	Total
1	**Cost Savings**														
2	Operating	$0.0	$742.6	$850.2	$1,034.4	$1,276.5	$1,384.6	$1,390.5	$1,400.5	$1,410.5	**$9,489.8**	$1,420.5	$1,430.5	$1,440.5	**$13,781.2**
3	Capital	$0.0	$229.4	$301.7	$340.5	$338.9	$336.0	$329.9	$329.9	$329.9	**$2,536.2**	$329.9	$329.9	$329.9	**$3,525.8**
4	**Total**	**$0.0**	**$972.0**	**$1,151.9**	**$1,374.9**	**$1,615.5**	**$1,720.6**	**$1,720.4**	**$1,730.4**	**$1,740.4**	**$12,025.9**	**$1,750.4**	**$1,760.4**	**$1,770.4**	**$17,307.0**
5	**Transition / Transaction Costs (Note 1)**														
6	Operating	-$800.0	-$250.0	-$50.0	-$50.0	$0.0	$0.0	$0.0	$0.0	$0.0	**-$1,150.0**	$0.0	$0.0	$0.0	**-$1,150.0**
7	Capital	-$130.0	-$375.0	-$275.0	-$200.0	$0.0	$0.0	$0.0	$0.0	$0.0	**-$980.0**	$0.0	$0.0	$0.0	**-$980.0**
8	**Total**	**-$930.0**	**-$625.0**	**-$325.0**	**-$250.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**-$2,130.0**	**$0.0**	**$0.0**	**$0.0**	**-$2,130.0**
9	**Net Savings**														
10	Operating	-$800.0	$492.6	$800.2	$984.4	$1,276.5	$1,384.6	$1,390.5	$1,400.5	$1,410.5	**$8,339.8**	$1,420.5	$1,430.5	$1,440.5	**$12,631.2**
11	Capital	-$130.0	-$145.6	$26.7	$140.5	$338.9	$336.0	$329.9	$329.9	$329.9	**$1,556.2**	$329.9	$329.9	$329.9	**$2,545.8**
12	**Total**	**-$930.0**	**$347.0**	**$826.9**	**$1,124.9**	**$1,615.5**	**$1,720.6**	**$1,720.4**	**$1,730.4**	**$1,740.4**	**$9,895.9**	**$1,750.4**	**$1,760.4**	**$1,770.4**	**$15,177.0**

In response to EB-2017-0212 interrogatory 1-Staff-8, projected cost savings were further componentized as follows:

TABLE 1-31: EB-2017-0212 MAADS COMPONENTIZATION OF PROJECTED COST SAVINGS FROM EPI/STEI MERGER – INTERROGATORY RESPONSE

Line No.	Business Area	Cost Savings by Year ($000's)								
		2018	2019	2020	2021	2022	2023	2024	2025	2026
1	**OM&A**									
2	Management and consulting fees	$432	$432	$432	$432	$432	$432	$432	$432	$432
3	IT support costs	$0	$0	$150	$300	$300	$300	$300	$300	$300
4	Corporate governance costs	$30	$30	$30	$30	$30	$30	$30	$30	$30
5	Regulatory costs	$55	$55	$120	$207	$207	$207	$207	$207	$207
6	Insurance and employee benefits	$3	$23	$23	$23	$23	$23	$23	$23	$23
7	Staff attrition*	$165	$188	$184	$217	$311	$311	$311	$311	$311
8	Misc.	$58	$122	$95	$68	$82	$87	$97	$107	$117
9	**Total OM&A**	**$743**	**$850**	**$1,034**	**$1,277**	**$1,385**	**$1,390**	**$1,400**	**$1,410**	**$1,420**
10	**Capital**									
11	Fleet purchasing	$200	$200	$200	$200	$200	$200	$200	$200	$200
12	Inventory/stock	$0	$50	$50	$50	$50	$50	$50	$50	$50
13	Deployment efficiency	$29	$52	$91	$89	$86	$80	$80	$80	$80
14	**Total Capital**	**$229**	**$302**	**$341**	**$339**	**$336**	**$330**	**$330**	**$330**	**$330**

* Minimal level of staff attrition has occurred in the latter half of 2017.

REALIZED NET SAVINGS

Realized ongoing cost savings from 2017 to 2025 from the EPI/ STEI merger total $11.3M (including both capital and expense cost savings). Transition / transaction costs incurred were $1.7M, resulting in realized net savings of $9.5M as shown below:

TABLE 1-32: REALIZED NET SAVINGS FROM EPI/STEI MERGER

		Actuals										
Line No.	Description	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
1	**Cost Savings**											
2	Operating	$0.0	$0.0	$510.1	$824.9	$997.6	$1,208.3	$1,568.4	$1,639.7	$1,709.0	$1,764.7	$10,222.7
3	Capital	$0.0	$0.0	$237.5	$50.7	$51.6	$132.5	$136.7	$141.2	$148.0	$153.3	$1,051.6
4	**Total**	**$0.0**	**$0.0**	**$747.6**	**$875.6**	**$1,049.2**	**$1,340.9**	**$1,705.2**	**$1,780.9**	**$1,857.1**	**$1,918.0**	**$11,274.3**
5	**Transition / Transaction Costs (Note 1)**											
6	Operating	($168.0)	($547.0)	($203.0)	($27.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($945.0)
7	Capital	$0.0	$0.0	($137.0)	($535.0)	($120.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($792.0)
8	**Total**	**($168.0)**	**($547.0)**	**($340.0)**	**($562.0)**	**($120.0)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**($1,737.0)**
9	**Net Savings**											
10	Operating	($168.0)	($547.0)	$307.1	$797.9	$997.6	$1,208.3	$1,568.4	$1,639.7	$1,709.0	$1,764.7	$9,277.7
11	Capital	$0.0	$0.0	$100.5	($484.3)	($68.4)	$132.5	$136.7	$141.2	$148.0	$153.3	$259.6
12	**Total**	**($168.0)**	**($547.0)**	**$407.6**	**$313.6**	**$929.2**	**$1,340.9**	**$1,705.2**	**$1,780.9**	**$1,857.1**	**$1,918.0**	**$9,537.3**

Further componentization of realized cost savings, transition costs and net savings are detailed below:

TABLE 1-33: COMPONENTIZATION OF NET SAVINGS FROM EPI/STEI MERGER

Line No.	Business Area	Summary	Cost Savings by Year ($000's)										
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
1	**Cost Savings - Operating**												
2	Management and consulting fees	Administrative costs were absorbed by the merged LDC			324.0	437.8	445.9	455.1	469.4	484.9	508.2	526.5	3,651.8
3	IT support costs	STEI outsourced CIS costs absorbed by the merged LDC			0.0	0.0	0.0	0.0	240.0	247.9	259.8	269.2	1,016.9
4	Corporate governance costs	Reduction of board members from EPI/STEI boards of directors			30.0	40.5	41.3	42.1	43.5	44.9	47.1	48.7	338.1
5	Regulatory costs	Avoided STEI 2020 rebasing and EPI 2021 rebasing (cost amort'n)				0.0	120.0	240.0	247.6	255.7	268.0	277.7	1,408.9
6	Insurance and employee benefits	Combined purchasing power			15.0	20.3	20.6	21.1	21.7	22.4	23.5	24.4	169.1
7	Staff attrition	Staff attrition synergies primarily in Finance and Administration			97.9	237.0	298.9	377.3	387.7	398.3	410.9	424.0	2,632.0
8	Misc.	Elimination of duplicate licences, memberships, audit costs, etc			43.2	89.2	90.8	92.7	95.6	98.8	103.5	107.2	721.1
9	Strathroy office closure	Closure of Strathroy office and staff integration into St. Thomas office					(20.0)	(20.0)	63.0	86.8	88.0	87.0	284.8
9	**Subtotal: Cost Savings - Operating**			**0.0**	**510.1**	**824.9**	**997.6**	**1,208.3**	**1,568.4**	**1,639.7**	**1,709.0**	**1,764.7**	**10,222.7**
10	**Cost Savings - Capital**												
11	Fleet purchasing	Sharing of specialized equipment across service centres			200.0								200.0
12	Inventory/stock	Sharing of specialized inventory/stock across service centres			37.5	50.7	51.6	52.7	54.3	56.1	58.8	60.9	422.7
13	Deployment efficiency	Strategic deploy lines construction crews post OLRB decision						79.9	82.4	85.1	89.2	92.4	429.0
14	**Subtotal: Cost Savings - Capital**			**0.0**	**237.5**	**50.7**	**51.6**	**132.5**	**136.7**	**141.2**	**148.0**	**153.3**	**1,051.6**
15	**Total Cost Savings**			**0.0**	**747.6**	**875.6**	**1,049.2**	**1,340.9**	**1,705.2**	**1,780.9**	**1,857.1**	**1,918.0**	**11,274.3**
16	**Transition Costs / Transaction Costs - Operating**												
17	Legal & consulting (transactional)	**See Note 1**	168.0	474.0	138.0	26.0							806.0
18	Project management & other	Project management & other		14.0	6.0								20.0
19	Process harmonization	Includes mapping, policies and processes harmonization		40.0	50.0								90.0
20	Branding harmonization	Including signage, letterhead, trucks		19.0	9.0	1.0							29.0
21	**Subtal: Transition Costs - Operating**		**168.0**	**547.0**	**203.0**	**27.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**945.0**
22	**Transition Costs - Capital**												
23	CIS & FIS systems merge	Including integration of CIS and FIS systems			80.0	340.0	61.0						481.0
24	Operational technologies	Introduce SCADA, GIS, OMS, Control Room to St. Thomas and harmonization			35.0	47.0	59.0						141.0
25	Metering / MDMR / Settlement	Including harmonization of metering data and settlement integration			22.0	45.0							67.0
26	IT network security	Connect consistent IT security across multiple office sites				19.0							19.0
27	Phone system	Harmonize to one seamless phone system across office locations				84.0							84.0
28	**Subtotal: Transition Costs - Capital**			**0.0**	**137.0**	**535.0**	**120.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**792.0**
29	**Total Transition Costs**			**547.0**	**340.0**	**562.0**	**120.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**1,737.0**
30	**Net Savings**			0.0	407.6	313.6	929.2	1,340.9	1,705.2	1,780.9	1,857.1	1,918.0	9,537.3

Note 1: Transaction costs included legal & consulting related to merger agreements, external accounting and the MAADs application. Entegrus transaction costs were borne by the shareholder.

As shown above, the cost savings from the merger exceeded the transition / transaction costs.

1.11.5 EFFICACY OF RATE PLAN

As described in the EPI/STEI MAADs (merger) application (EB-2017-0212), the applicants proposed an 8-year deferred rebasing period in consideration of anticipated incremental external costs associated with the transaction, as well as associated one-time and ongoing benefits. In its EB-2017-0212 Decision, the OEB approved the 8-year rebasing deferral and noted that "the most significant and enduring anticipated benefit to customers should be the lower cost structures achieved through the deferred rate-setting period resulting in lower rates upon rebasing than would otherwise have been achievable."

As noted on page 23 of the MAADs application, absent the merger, both LDCs would likely have filed rebasing applications during the deferral period. Instead, annual Price Cap Incentive Rate Mechanism ("IRM") applications were filed annually for the EPI-Main and EPI-St. Thomas rate zones from 2018 to 2025, providing ratepayers with an extended period of rate stability. The MAADs application further projected that, due to cost synergies, 2026 rebased distribution rates would be 3%-4% lower than in a non-merger than what would have otherwise occurred in the absence of the transaction.

Based on the analysis in Table 1-32 above, actual ongoing cost savings result in the distribution rates being sought in this Application that are approximately 4% lower than would have otherwise occurred.

1.11.6 ICM Applications

To date, EPI has not filed any Incremental Capital Module ("ICM") applications and is not proposing to include any Advanced Capital Module ("ACM") or ICM applications in rate base in this Application.

EPI does not currently have any plans to file any ICM applications during the 2026-2030 period. However, given evolving provincial energy policies and increasing load at EPI's 36 supply points, capacity needs may arise that require the filing of an ICM application in the future. EPI expressly reserves the right to do so if needed. EPI will continue to monitor capacity closely.

1.12 Impacts of COVID-19 Pandemic

On March 11, 2020, the World Health Organization declared the COVID-19 outbreak a global pandemic. Shortly thereafter, Ontario declared a State of Emergency on March 17, 2020, mandating the closure of non-essential businesses.

The pandemic persisted for over two years, creating widespread disruption and hardship. For EPI, the pandemic underscored the importance of safety, adaptability, teamwork and business continuity. Between 2020 and 2022, EPI implemented a range of measures to protect employees and the public, maintain reliable service, and respond to evolving public health guidance. EPI staff transitioned between remote work and Return to Office three times, with a final Return to Office occurring in April 2022.

EPI is proud of its safety and operational resilience during this period. EPI does not seek recovery of COVID-19 deferral account costs in this Application.

1.12.1 OM&A and Capital Impacts

Upon the declaration of the State of Emergency, EPI transitioned all non-trades staff to remote work. Laptops and mobile phones were deployed, and virtual meeting tools such as Zoom and Microsoft Teams were implemented. Trades staff remained in the field, operating under enhanced safety protocols. These included restructuring line crews into two-person units traveling in separate vehicles (including rentals), deployment of portable wash stations, and provision of enhanced personal protective equipment ("PPE"), including flame-resistant masks and face shields. Line crews were also decentralized across then then-three operational centres (St. Thomas, Strathroy and two encampments in Chatham).

Office-based safety measures included mandatory masking, hand sanitizing stations, directional signage, plexiglass barriers, increased cleaning, and occupancy limits. These actions increased both OM&A and capital costs.

Starting in the summer of 2020, EPI experienced a wave of retirements. Recruitment activities were adapted to pandemic conditions, with virtual interviews, visitor screening, and physically distanced in-person interviews conducted as required. Throughout, EPI followed provincial public health guidance to ensure safety and business continuity.

In late 2020 and 2021, global supply chain disruptions affected material availability and pricing. EPI mitigated these impacts by leveraging its membership in the Grid Smart City purchasing cooperative to place bulk orders for standardized equipment, diversifying supplier relationships, and extending lead times. Collaboration with developers further supported continuity of work.

In March 2022, following the relaxation of provincial mandates, EPI, in consultation with its Joint Health and Safety Committee, began a phased reduction of pandemic protocols. The third and final Return to Office occurred in April 2022.

1.12.2 Customer Support and Recovery Status

Throughout the pandemic, EPI supported customers through several OEB programs, including the fixed Time-of-Use ("TOU") rate structure and the extension of the 2020 disconnection moratorium. In June 2020, EPI also administered the COVID-19 Energy Assistance Program ("CEAP"), which provided one-time relief to residential and small business customers. EPI actively engaged with customers to facilitate program participation, with CEAP remaining available through December 2021.

As of August 2025, EPI has largely returned to pre-pandemic operating conditions, having successfully navigated a period of unprecedented disruption. The lessons learned and investments made during this time, including advancements in IT infrastructure, workplace practices and safety, have evolved the EPI workplace and positioned the organization to respond effectively to future challenges. However, EPI continues to manage supply chain issues, rising prices and higher inflation through careful planning.

As previously noted, EPI does not seek recovery of COVID-19 deferral account costs in this Application.

1.12.3 Load Forecast Impacts

The EPI load forecast was prepared using historical actuals up to the end of 2024. To address the anomalous energy consumption patterns observed during the COVID-19 pandemic, EPI introduced a "COVID" variable into its multi-variate regression analysis. This variable was designed to reflect the varying intensity and duration of pandemic-related disruptions such as lockdown measures and increased remote work.

The COVID variable was specified by month to capture these temporal dynamics accurately. The variable takes the following values:

- 0 for all months prior to March 2020;
- 0.5 in March 2020 to reflect the onset of emergency measures;
- 1.0 in April and May 2020, the period of strictest lockdowns;
- 0.5 in June 2020, during partial reopening;
- 0 in all months thereafter.

This COVID variable was found to be statistically significant in the model and effectively captures the influence of COVID-related disruptions. Its inclusion ensures that the 2026 Test Year forecast is not biased by the anomalous conditions present in 2020.

Full details of the load forecast impacts can be reviewed in Exhibit 3, Section 3.2.3 – COVID Flag in the Regression Analysis.

ATTACHMENT 1-A

Certification of Evidence

Entegrus Powerlines Inc.
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Chatham, ON N7M 5K2
Phone: (519) 352-6300
Toll Free: 1-866-804-7325
entegrus.com

Certification of Evidence

As Chief Financial Officer & Vice President of IT of Entegrus Powerlines Inc., I certify that, to the best of my knowledge, the evidence filed in support of this Application, including the models and appendices, is accurate and complete; and complies with Chapters 2 and 5 of the Ontario Energy Board's Filing Requirements for Electricity Distribution Rate Applications – 2025 Edition for 2026 Rate Applications dated December 9, 2024 and updated May 7, 2025.

In addition, I certify that, to the best of my knowledge, Entegrus has the appropriate processes and internal controls in place for the preparation, review, verification and oversight of all deferral and variance accounts, regardless of whether the accounts are proposed for disposition.

Lastly, I certify that the Application and any evidence filed in support of the Application does not include any personal information unless it is filed in accordance with Rule 9A of the Ontario Energy Board's Rules of Practice and Procedure (and the Practice Direction on Confidential Filings, as applicable).

Chris Towne
Digitally signed by Chris Towne
Date: 2025.08.28 13:46:43 -04'00'

Chris Towne

Chief Financial Officer & Vice President of IT

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BOARD CERTIFICATION

The Entegrus Powerlines Inc. Board of Directors certifies that it is aware of and approves the submission of Entegrus Powerlines Inc.'s 2026 Cost of Service Application.

This certification is provided pursuant to the Ontario Energy Board's *Chapter 2, Filing Requirements for Electricity Distribution Rate Applications*, as dated on December 9, 2024.

Scott Praill
Chair, Board of Directors
Entegrus Powerlines Inc.

Aug 6/25
Date

ATTACHMENT 1-B

EPI 2026-2030 Business Plan

ENTEGRUS™

2026-2030 BUSINESS PLAN

1 CONTENTS

2 EXECUTIVE SUMMARY 3

2.1 Utility Description 3

2.2 the evolution of entegrus 3

2.3 Corporate Structure 5

3 OUR MISSION, VISION, AND CORE VALUES 6

3.1 VISION, MISSION AND CORE VALUES 6

4 THE EPI BUSINESS PLAN STRATEGY, CORE VALUES AND THE RENEWED REGULATORY FRAMEWORK FOR ELECTRICITY 6

4.1 Safety 8

4.2 Inspired and Empowered people 13

4.3 Customer and Community Focus 16

4.4 Operational Excellence 23

4.5 Sustainable Growth 39

5 ATTACHMENT 1: FINANCIAL STATEMENTS

6 ATTACHMENT 2: 2023 SCORECARD

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.

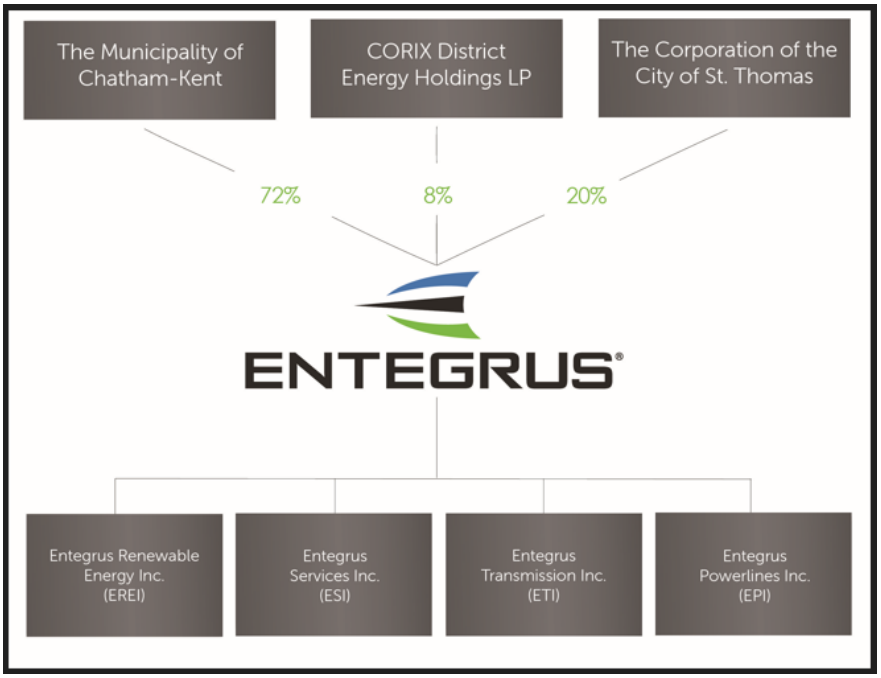
The pandemic period triggered a sustained and broad-based rise in inflation across the Canadian economy. From 2019 to 2025, the inflation factor set by the OEB for its Price Cap Incentive Rate-setting mechanism increased cumulatively by 20.7%. This reflects the broader trend of elevated inflation in 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)			
2024: SAIDI			
Feeder	SAIDI	Ranking	Change in Rank
1M2	4.7736	1	↑+9
27M5	4.1266	2	↑+21
1M6	3.2593	3	↑+8
5M17	2.5818	4	↑+21
24M4	2.5698	5	↑+8
DTF1	2.0280	6	↑+25
5M4	1.5602	7	↑+11
5M4	1.5602	8	↑+10
5M3	1.3848	9	↑+5
29M2	1.2518	10	↓-8
5M15	1.1701	11	↑+8
5M15	1.1701	12	↑+7
5M22	1.0177	13	↑+3
5M16	1.0115	14	↓-13
5M7	0.9973	15	↓-10
27M10	0.9629	16	↑+5
MBF3	0.8558	17	↔
27M1	0.8281	18	↑+9
BOF1	0.7757	19	↓-10
5M21	0.6116	20	↓-12
5M8	0.5303	21	↑+1
1M5	0.3759	22	↓-16
29M4	0.2610	23	↓-11
393M22	0.1840	24	↑+9
TDSF1	0.1511	25	↓-18
ERF2	0.1113	26	↓-23
52M24	0.0506	27	↑+3
27M6	0.0467	28	↓-8
TDSF2	0.0389	29	↓-25
1M1	0.0253	30	↓-1
MEF3	0.0139	31	↓-16
NBF2	0.0045	32	↓-4

SAIFI Rank (Target 1.08)			
2024: SAIFI			
Feeder	SAIFI	Ranking	Change in Rank2
1M2	5.1000	1	↑+25
1M6	3.3028	2	↑+1
27M5	3.2143	3	↑+18
5M4	3.1435	4	↑+9
5M4	3.1435	5	↑+8
5M21	3.0792	6	↔
24M4	2.1082	7	↑+15
5M17	1.9875	8	↑+19
5M22	1.5838	9	↑+2
5M7	1.3743	10	↓-9
1M5	1.2443	11	↓-6
5M3	1.1845	12	↔
DTF1	1.1525	13	↑+20
27M1	1.1133	14	↑+15
29M2	1.0413	15	↓-13
5M15	0.9177	16	↑+8
5M15	0.9177	171	↓-147
5M8	0.8658	18	↓-8
5M16	0.6163	19	↓-15
BOF1	0.5791	20	↓-11
27M10	0.5393	21	↓-6
MBF3	0.3868	22	↓-3
29M4	0.2331	23	↓-9
NBF2	0.1991	24	↑+8
27M6	0.1913	25	↑+3
393M22	0.1393	26	↑+4
ERF2	0.0702	27	↓-11
TDSF2	0.0467	28	↓-20
1M1	0.0410	29	↑+2
TDSF1	0.0332	30	↓-23
52M24	0.0139	31	↓-11
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						
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

Scorecard - Entegrus Powerlines Inc.

8/15/2024

Performance Outcomes	Performance Categories	Measures		2019	2020	2021	2022	2023	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		98.04%	96.91%	97.60%	98.55%	97.48%	↑	90.00%	
		Scheduled Appointments Met On Time		99.53%	99.83%	99.71%	100.00%	99.96%	↑	90.00%	
		Telephone Calls Answered On Time		65.61%	79.11%	81.26%	68.42%	83.75%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		79	74	85	81	75			
		Billing Accuracy		99.90%	99.81%	99.91%	99.91%	99.95%	↑	98.00%	
		Customer Satisfaction Survey Results		94	93	92	93	94			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness		81.00%	81.00%	78.00%	78.00%	79.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	1	4	1	1	0	↓		2
			Rate per 10, 100, 1000 km of line	0.805	1.297	0.329	0.311	0.000	↓		0.610
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.73	1.47	1.09	1.76	1.31	↓		1.42
		Average Number of Times that Power to a Customer is Interrupted [2]		1.02	1.18	1.02	1.18	0.93	↓		1.01
	Asset Management	Distribution System Plan Implementation Progress		85.6	112.4	20.2	40.6	61.9			
	Cost Control	Efficiency Assessment		2	2	1	1	1			
		Total Cost per Customer [3]		$566	$553	$558	$627	$713			
		Total Cost per Km of Line [3]		$10,982	$11,008	$10,670	$11,977	$13,731			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Connection of Renewable Generation**	New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.41	1.23	1.06	1.08	1.08			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.20	1.30	1.24	1.25	1.39			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.19%	9.19%	9.19%	9.19%	9.19%			
			Achieved	10.58%	8.23%	9.29%	7.85%	8.79%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.

Legend:

5-year trend
↑ up ↓ down → flat

Current year
target met target not met

2023 Scorecard Management Discussion and Analysis ("2023 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2023 Scorecard MD&A:

https://www.oeb.ca/oeb/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

Entegrus Powerlines Inc. ("Entegrus") owns, operates and manages the assets associated with the distribution of electrical power to approximately 62,910 customers in 17 Southwestern Ontario communities. The roots of Entegrus extend back to the formation of Chatham Hydro in 1914.

The communities serviced by Entegrus in 2023 are: Blenheim, Bothwell, Chatham (including a portion of the Township of Raleigh known as the "Bloomfield Business Park"), Dresden, Dutton, Erieau, Merlin, Mount Brydges, Newbury, Parkhill, Ridgetown, Strathroy, Thamesville, Tilbury, Wallaceburg, Wheatley and St. Thomas. Additional details are provided in the Entegrus Electricity Distribution License (ED-2002-0563).

On April 1, 2018, Entegrus amalgamated with St. Thomas Energy Inc. ("STEI"), a licensed electricity distributor operating within the City of St. Thomas. The merged electricity distributor continues as Entegrus. The scorecard results discussed herein relate to the combined 2023 results.

Entegrus monitors the scorecard measures on an ongoing basis and continuously seeks opportunities to improve its performance. The company is committed to meeting the needs of its customers both today and in the future. Entegrus is confident that its focus on customer outcomes will allow it to continue to meet or exceed performance targets.

Entegrus is committed to continuous year over year performance improvement for 2024 and beyond.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  In 2023, Entegrus connected 97.48% of 1,666 eligible low-voltage residential and small business customers (those utilizing connections under 750 volts) to its system within the five-day timeline prescribed by the OEB. For the five-year period from 2019 to 2023, Entegrus has consistently performed better than the industry target of 90% in this area.

- **Scheduled Appointments Met on Time**
  Entegrus scheduled 2,700 appointments in 2023 to complete work requested by customers (where customer presence is required). Entegrus met 99.96% of these appointments on time. For the five-year period from 2019 to 2023, Entegrus has consistently performed better than the industry target of 90% in this area.

- **Telephone Calls Answered on Time**
  In 2023, Entegrus Customer Service received 47,269 calls from its customers – an average of over 187 calls per working day. In 83.75% of instances, Entegrus answered the call within 30 seconds or less. This result exceeds the OEB-mandated 65% target for timely call response.

  Entegrus staffs its Customer Service Call Centre to meet the 65% target, while balancing the need to prudently deploy resources in all areas of the business. For the five-year period from 2019 to 2023, Entegrus has consistently met the industry target of 65% in this area.

Customer Satisfaction

- **First Contact Resolution**
  Entegrus engages a third-party service provider to conduct ongoing First Contact Resolution ("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. However, FCR can be measured in a variety of ways and further regulatory guidance will be necessary in order to achieve meaningful, consistent and comparable information across electricity distributors.

  Entegrus believes that best practice is to measure FCR based on ongoing third-party surveys of a random sample of those customers who have recently contacted Entegrus. Accordingly, Entegrus' FCR is measured based on live agent transactional phone surveys conducted by a third-party service provider. To facilitate these surveys, throughout the year Entegrus provides the third-party service provider with a report of all customers who had contacted Entegrus Customer Service by telephone within the previous two weeks.

The third-party service provider’s telephone agents, in turn, contact and survey Entegrus customers. Customers are asked to rate various facets of their customer experience and are also asked if their issue (i.e. their reason for calling) was resolved on their first contact to Entegrus. In 2023, the service provider’s agents surveyed a random sample of 412 Residential and Small Business customers from January to October 2023. Of the 412 customers surveyed (the denominator), 308 customers (the numerator) indicated that their issue was resolved on the first call to Entegrus. This equates to the reported FCR result of 75%.

Entegrus continues to maintain its strong FCR results by implementing recommendations from the service provider. Accordingly, Entegrus has continued to engage the third-party service provider to assist with ongoing FCR measurement and customer service strategy improvements on specific issue types.

- **Billing Accuracy**
  In 2023, Entegrus issued 766,062 bills and achieved a billing accuracy of 99.95%. This compares favourably to the prescribed OEB target of 98%.

  Entegrus continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**
  Entegrus engages a third-party service provider to conduct annual Customer Satisfaction surveys.

  In 2023, the third-party service provider conducted a random telephone survey for the period November 16, 2023 to November 24, 2023. A total of 502 customers were surveyed, however seven customers did not respond. Of the remaining 495 customers who responded (the denominator), 464 customers (the numerator) rated their Overall Satisfaction in the top 3 boxes. This equates to the reported Customer Satisfaction result of 94%, which is comparable to previous years.

  Customer Satisfaction is a key area of focus for Entegrus. Accordingly, Entegrus will continue to measure Customer Satisfaction annually, as opposed to the regulatory requirement to measure it every other year.

Safety

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**

  On a bi-annual basis, Entegrus engages a third-party service provider to conduct Public Safety Awareness surveys. The surveys are based upon a representative sample of each electrical distributor’s service territory population and gauges awareness levels of key electrical safety concepts related to distribution assets. The surveys provide a benchmark of levels of awareness including identifying gaps where additional education and awareness efforts may be required. In accordance with OEB requirements, the surveys are conducted every other year. Accordingly, the survey results described below were completed for the 2023 scorecard and will also be applicable to the 2024 scorecard.

Entegrus conducted a public safety awareness campaign in Q1 of 2024 utilizing local media and digital website content. Further, Entegrus continues to assist and participate in community safety events.

Entegrus engaged a third-party service provider to conduct stratified random telephone surveys of 603 Ontario residents, ages 18 or older, currently residing in the Entegrus service territory during the period from March 6, 2024 and March 18, 2024. The survey asked residents electrical safety questions and then an overall index score was calculated in accordance with a prescribed algorithm. Public Awareness of Electrical Safety results for 2023/2024 showed a slight increase compared to the prior results at 79%.

- **Component B – Compliance with Ontario Regulation 22/04**

Ontario Regulation 22/04 (Electrical Distribution Safety) establishes objective-based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. The regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service. Entegrus is audited annually for compliance and was found to be compliant in 2023.

- **Component C – Serious Electrical Incident Index**

This is measured as the number of non-occupational (general public) serious electrical incidents occurring on Entegrus' distribution system and reported to the ESA, expressed as a raw number and as the number per 1,000 km of line. In 2023, no incidents were reported.

In accordance with its foremost core value of Safety, Entegrus' staff examine the circumstances surrounding such incidents and incorporate insights into the content of relevant employee safety training and public safety awareness programs.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

For this measure, the OEB establishes baseline targets based on the average of the distributor's performance for the period 2016 – 2020 (the baseline period is updated every 5 years). Entegrus' 2023 result of 1.31 is favourable to prior year results and is also better than the target of 1.42. In recent years, Entegrus service territory has experienced more severe weather. In March 2023, the OEB standardized the methodology by which distributors report major weather events (which are excluded from these statistics). Thereafter, four weather events in 2023 met the major event threshold in 2023, which contributed to the favourable result versus target.

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. Entegrus continues to focus on the installation of smart grid equipment, which will contribute to a reduction in the duration and frequency of outages.

Entegrus continues to view reliability of electricity service as a high priority. As further discussed below, Entegrus continued to make substantial progress on its Distribution System Plan ("DSP") implementation in 2023.

- **Average Number of Times that Power to a Customer is Interrupted**
  For this measure, the OEB establishes baseline targets calculated as the average of the distributor's performance for the period 2016 – 2020 (the baseline period is updated every 5 years). Entegrus' 2023 result of 0.93 is better than the target of 1.01. As discussed above, despite experiencing more severe weather, this is the result of the four major events in 2023 that met the threshold to be excluded from the statistics.

  Entegrus continues to view reliability of electricity service as a high priority. As further discussed below, in 2021 Entegrus filed a combined and comprehensive 2021-2025 DSP. Entegrus made substantial progress on its DSP implementation in 2023.

Asset Management

- **Distribution System Plan Implementation Progress**
  Entegrus maintains a DSP that adopts a proactive, balanced approach to distribution system planning, infrastructure investment and replacement programs to address immediate risks associated with end-of-life assets; manage distribution system risks; ensure the safe and reliable delivery of electricity; and balance ratepayer and utility affordability.

  In 2021, Entegrus filed a combined and comprehensive 2021-2025 DSP, inclusive of both the Entegrus-Main and Entegrus-St. Thomas rate zones.

  Entegrus reports this metric based on percentage of actual life-to-date capital expenditures divided by the aggregate total DSP (5 year) capital expenditures. The Entegrus 2023 life-to-date actual capital expenditures were $43M (the numerator). The total projected DSP (5 year) capital expenditures are $69.5M (the denominator). This numerator and denominator equate to the reported DSP Implementation Progress figure of 61.9%.

  In 2023, the focus of the DSP was on continued distribution system access and renewal, including voltage conversions of sections of the system from lower voltages to 27.6 KV and additional system service investment, including deployment of smart grid technologies.

Cost Control

- **Efficiency Assessment**

  The total costs for Ontario local electricity distribution companies are evaluated based on econometric modeling conducted by a consultant (the Pacific Economics Group LLC) on behalf of the OEB to produce a single efficiency ranking. The 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.

  In 2023, Entegrus' actual costs for 2021-2023 were 27.8% lower than the costs predicted by the OEB's consultant. For the third consecutive year, Entegrus was placed in Group 1, where a Group 1 distributor is defined as having actual costs which are at least 25% lower than the costs predicted for the distributor. Group 1 is considered "most efficient". In 2023, Entegrus ranked 14th out of 54 distributors in terms of cost performance results versus benchmark.

- **Total Cost per Customer**

  Total cost per customer is calculated as the sum of Entegrus' capital and operating costs (including certain adjustments to make the costs more comparable between distributors), divided by the total number of customers that Entegrus serves. Entegrus' cost performance result for 2023 is $713 per customer.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that Entegrus operates to serve its customers, which equates to $13,731 per kilometer of line.

Connection of Renewable Generation

- **New Micro-Embedded Generation Facilities Connected on Time**

  Electricity distributors are required to connect an applicant's micro-embedded generation facility (i.e. MicroFIT projects of less than 10kW or net metering projects) 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 minimum acceptable performance level for this measure is 90%.

  In 2023, Entegrus connected the 13 new micro-embedded generation facility requests received within the prescribed time frame of five business days. Entegrus works closely with its customers and their contractors to address any connection issues to ensure the project is connected on time.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**
  Liquidity is calculated by dividing Current Assets by Current Liabilities. This ratio is also known as Working Capital Ratio and measures an entity's ability to pay short-term financial obligations. As an indicator of financial health, a Liquidity Ratio of greater than 1 is considered good, as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  The Entegrus current ratio was 1.08 in 2023. Entegrus' goal is to maintain a Liquidity Ratio of more than 1.00. As noted above, this means that the organization has resources available in the short term to meet its short-term financial obligations.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**
  The OEB uses a deemed capital structure of 60% debt, 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 levered than the deemed capital structure. A high debt to equity ratio may indicate 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.

  As demonstrated by its 2023 Leverage Ratio of 1.39, Entegrus continues to maintain a debt-to-equity structure that closely approximates the deemed 60% to 40% capital mix as set out by the OEB. Entegrus' strong financial position is further supported by its recent Standard & Poor's Rating Services rating of "A".

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  Entegrus' 2023 distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.19%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**
  Entegrus' achieved a 2023 Regulatory Return on Equity ("ROE") of 8.79%, which is within the +/-3% range of Deemed ROE allowed by the OEB.

Note to Readers of 2023 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard and could be markedly different in the future.

ATTACHMENT 1-C

Corporate Governance Policies & Documents

ENTEGRUS POWERLINES INC.

BOARD OF DIRECTORS MANDATE AND CHARTER

1. OBJECTIVES

The Board of Directors ("**Board**") of **ENTEGRUS POWERLINES INC.** (the "**Corporation**") is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of the Corporation.

The Board is appointed by the Entegrus Inc. Board and is obligated to act in the best interests of the Corporation.

2. COMPOSITION OF THE BOARD OF DIRECTORS

The Board shall consist of a minimum of nine (9) members and are appointed in accordance to the Shareholder Agreement ("SA") of the Corporation. The Board members shall serve at the pleasure of the Shareholders and the Shareholders shall appoint the Board annually.

The Board Chair shall be appointed from among the Board's directors. The Board shall provide the Chair with a position description.

The qualifications for nomination, appointment and continuing service on the Board as a Director are set forth in the By-law and SA.

Members of the Board shall be entitled to receive such remuneration for acting as members of the Board as may be determined from time to time by the Board on recommendation of the Corporation's Compensation and Governance Committee ("CGC") upon approval of the Shareholders.

Board of Governors' Charter

The Board's Charter outlines how the Board of Directors will satisfy the requirements set forth in it's mandate. This Charter comprises:

- Operating Principles
- Operating Procedures
- Specific Responsibilities and Duties

3. OPERATING PRINCIPLES

The Board shall fulfill its responsibilities within the context of the following principles:

3.1 Board Values

The Board of Directors will act in accordance with the Board's policies and industry best practices as applicable.

3.2 Communications

The Chair and members of the Board expect to have direct, open and frank communications throughout the year with the Chair and Management.

3.4 Meeting Agenda

The Board meeting agendas shall be the responsibility of the Board Chair. The President and Chief Executive Officer will develop meeting agendas in consultation with the Board Chair, Board members and assigned Management.

3.5 Board Expectations and Information Needs

The Board shall communicate its expectations to Management with respect to the nature, timing and extent of its information needs. The Board expects that written material supporting agenda items will be received from Management at least one week in advance of the meeting dates.

3.6 In-Camera Meetings

At each meeting of the Board, the members of the Board shall meet at their discretion in private sessions that allow the Board to discuss matters (a) amongst themselves, and (b) with Management. Actionable items resulting from these sessions will be recorded in the minutes in accordance with Guidelines for *in camera* meetings.

3.7 Adequate Resources

In all instances where the Board Chair or the Board believes that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of external experts, the Chair shall engage the necessary experts subject to prior notice and approval of the Board. The Board shall be kept apprised of both the selection of the experts and the expert's findings by the Board Chair at regular Board meetings.

The Board shall consider from time to time its resources including the adequacy of the information provided to it with respect to oversight of the Management of the Corporation and shall confer with Management with respect to its findings.

Members of the Board shall have the right, for the purpose of discharging their respective powers and responsibilities, to inspect any relevant records of the Corporation and its affiliates.

3.8 Board Self-Assessment

The Board shall annually review, discuss and assess its own performance and individual member's performance. In addition, the Board shall annually review its role and responsibilities and complete an online Board survey. The Board shall reconsider its Mandate and Charter at least annually and report to the Compensation and Governance Committee with any recommendations for change.

4. OPERATING PROCEDURES

The Board shall fulfill its responsibilities within the context of the following procedures:

4.1 Frequency and Calling of Board Meetings

The Board shall meet at least quarterly and more frequently if circumstances dictate. Meetings shall be held at the call of the Board Chair or a majority of the Directors. Notice of a meeting of the Board will be given not less than seven (7) days before the meeting is to take place.

The meetings of the Board shall ordinarily include the Secretary and shall periodically include other senior officers as may be appropriate and as may be desirable to enable the Board to become familiar with the Corporation's management team.

4.2 Quorum

A majority of director's present provided that at least one (1) nominee director of each Shareholder entitled to nominate a director is present. Each voting member will be entitled to one vote and the Board Chair will not have a second or casting vote in the case of an equality of votes.

4.3 Secretary of Board Meetings

Unless the Board otherwise specifies, the Corporate Secretary shall act as secretary of all meetings of the Board. In the absence of the Corporate Secretary, the Board Chair shall designate a person to act as the Secretary of the meeting.

The Corporate Secretary shall keep minutes of its meetings in which shall be recorded all actions taken by the Board. Such minutes shall be made available to Board members at their request and all such minutes shall be approved by the Board for entry in the records of the Corporation.

4.4 Chair of Board Meetings

In the absence of the Board Chair at any meeting of the Board, the Chair of the Board may delegate a Board member to perform the duties of the Chair or the Board members present may elect one among them to perform the duties of the Chair.

4.5 Minutes of Board Meetings

A copy of the minutes of each meeting of the Board shall be provided to each member of the Board within thirty (30) calendar days from the meeting date.

5. SPECIFIC RESPONSIBILITIES AND DUTIES

5.1 General Responsibilities

a) The Board shall oversee the management and affairs of the Corporation. In doing so, the Board shall establish a productive working relationship with the President and Chief Executive Officer and other members of senior management.

b) The officers of the Corporation, headed by the President and Chief Executive Officer, shall be responsible for general day to day management of the Corporation and for making recommendations to the Board with respect to long term strategic, financial, organization and related objectives.

c) The roles and responsibilities of the Board are intended to primarily focus on the formulation of long term strategic, financial and organizational goals for the Corporation and the monitoring of management performance. Without limitation, the Board shall (i) oversee management-driven strategic planning process and approve the Corporation's strategic plan, (ii) assess the principal risks of the Corporation's business and ensure appropriate systems are in place to manage such risks, (iii) select, monitor and evaluate the President and Chief Executive Officer for the Corporation and oversee succession planning at the senior management level, and (iv) monitor the effectiveness of the Corporation's internal control and management information systems to safeguard corporate assets.

d) The Board must gain and maintain reasonable assurance that EPI meets all financial reporting and disclosure obligations imposed on by applicable law and applicable regulations, rules, policies and other requirements relating to financial reporting and disclosure promulgated by governments and regulatory agencies ("Financial Reporting Obligations"). The Board recognizes that the most significant Financial Reporting Obligations are as follows:

1. To review and provide annual guidance to management about:

    (i) policies relating to cash flow, cash management and working capital, shareholder dividends and distributions;
    (ii) adjustments to capital structure;
    (iii) capital and debt issuances
    (iv) financial strategies;
    (v) polices for managing interest rate, foreign exchange, and investment risk;
    (vi) the financial aspects of insurance and risk management;
    (vii) tax planning and compliance;

(viii) proposed mergers, acquisitions, divestitures and strategic investments;

(ix) other transactions or financial issues that management desires to have reviewed by the Board or relevant Board Committee.

2. The Corporation's annual and interim financial statements must present fairly EPI's financial position, the results of its operations and its cash flows in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), International Financial Reporting Standards (IFRS) as well as certain industry related regulatory requirements;

3. The Corporation's annual financial statements must be audited and reported on by a firm of chartered accountants (the "external auditor") which is objective and independent; and material financial information concerning the Corporation must be disseminated to the Shareholders in a timely manner and all financial information concerning the Corporation must be accurate, complete and fairly presented.

e) The Board will oversee the Corporation's compliance with laws and regulations, which includes overseeing the Corporation's compliance with all applicable OEB policies and procedures.

f) With respect to significant risks and opportunities affecting the Corporation, the Board must gain and maintain reasonable assurance that the risks confronting the Corporation are identified, monitored and managed by the senior management of the Corporation.

In particular the board must gain and maintain reasonable assurance that:

Management has identified the most significant Risks currently confronting the Corporation and new significant risks which confront the Corporation will be identified in a timely manner and brought to the attention of the Board.

g) The Board shall when required for director recruitment consider the skills and competencies of the Board from the perspective of determining what additional skills and competencies would be helpful to the Board. The identification of specific candidates for consideration shall be the responsibility of the CGC which shall be guided by the findings of the Board in relation to competencies and skills.

h) The Board will ensure that the Corporation has the appropriate policies and procedures in place to establish just and reasonable rates which are:

(i) Consistent with similar utilities in comparable growth areas and as may be permitted by the *Ontario Energy Board Act*;

(ii) Intended to enhance the value of the Corporation; and

(iii) Consistent with the encouragement of economic development and activity within the communities that are served

i) The Board will review the Corporation's performance as to service quality and other factors used by the OEB in setting the rates the Corporation may charge to its customers and other similar financial and regulatory prudence standards.

j) The Board shall perform such other functions as are prescribed by law, as are assigned to the Board in the Corporation's By-Law and as it may from time to time determine in accordance with the plenary powers of the Board.

k) The Board shall receive at each Board meeting reports on health, safety and environmental matters as they affect the Corporation and its business.

l) The Board shall provide an orientation program for new Directors and continuing education opportunities for all Directors.

m) The Board will review and approve the annual business plan along with the operating and capital budgets. After the Board has approved the annual business plan, the Board must monitor its progress and achievement at each meeting of the Corporation's Board.

The Board will ensure it is in compliance with all applicable laws, regulations, rules, policies and other requirements of governments and regulatory agencies relating to human resources.

n) The Board shall approve the selection of the external auditors and the related remuneration and terms of engagement.

o) The Board may, from time to time, meet with the external auditors in camera in the absence of Management.

5.2 Senior Management

a) The Board will approve a position description for the President and Chief Executive Officer.

b) The Board will review with the Compensation and Governance Committee the objectives set for the President and Chief Executive Officer and performance in relation to such objectives.

c) The Board will review with the Compensation and Governance Committee the objectives of the Executive Team as provided by the President and CEO.

5.3 Communications

a) The Board will annually review and approve the Corporation's annual financial statements.

b) The Board will periodically review the means by which the Corporation Inc. can communicate with the Shareholders including the opportunity to do so at the annual general meeting and communications interfaces through the Corporation's website.

5.4 Governance Culture

The Board must use its best efforts to establish and sustain amongst all Directors a culture which incorporates the following values, and convictions:

a) acceptance of the Board's accountability for EPI's performance;

b) the conviction that Directors owe each other their best efforts in carrying out their duties and exercising their authority;

c) upholding the trust of the sole Shareholder with due regard to the interests of all stakeholders;

d) recognizing the importance of solidarity ("the board speaks only with one voice") when decisions are taken;

e) practicing personally, and within the Board, the accountabilities that are demanded of executives and employees;

f) insisting on the highest level of honesty, openness and integrity in all actions of the Board, Management and employees of EPI's; and

g) encouraging and fostering conditions which build and enhance trust and respect amongst all the Directors.

h) commitment to maintaining confidentiality of the Board and in-camera sessions (i.e., no external communications unless agreed to by the Board).

5.5 Other Business

The Board will consider any other matter referred to the Board by Entegrus Inc.

6. ACCOUNTABILITY

a) The Board Chair will report on the deliberations of the Board annually; and

b) The Board will review this Mandate and Charter each year at its third quarter meeting to assess its adequacy and endeavor to keep its members abreast of "best practices" and recommend changes.

CODE OF CONDUCT FOR DIRECTORS

Section 1: Governance Guidelines

1.1 Purpose

The Directors of Entegrus Inc. and its subsidiaries are committed to maintaining the highest standards for ethical business conduct and carrying out their responsibilities in a manner that inspires the confidence and trust of our shareholder and community. Accordingly, the Board has adopted this Code of Conduct for Directors as a guide to achieving these goals.

1.2 Definitions

(a) "Board" means the board of directors of the Corporation.

(b) "Corporation" means Entegrus Inc. and/or any of its subsidiaries.

(c) "Director" means a director of the Corporation.

(d) "Directors' Code" means this Code of Conduct for Directors.

(e) "Employee Code" means the Corporation's Employee Code of Conduct.

1.3 Guidelines

In performing their Board and Board Committee functions, our Directors will:

(a) Act diligently, openly, honestly and in good faith.

(b) Provide leadership in advancing the Corporations' Vision, Mission and Values.

(c) Discharge their duties, as members of the Board and of any Board Committees on which they serve, in accordance with their good faith business judgment and in the best interests of the Corporation.

(d) Become and remain familiar with the Corporation's business and the economic and competitive environment in which the Corporation operates and understand the Corporation's principal business plans, strategies and objectives; operational results and financial condition; and relative marketplace position.

(e) Commit the time necessary to prepare for, attend (in person, telephone or video conference, as appropriate) and actively participate in regular and special meetings of the Board and of the Board Committees on which they serve.

(f) Inform the Chair of the Board and the Chair of the Compensation and Governance Committee of changes in their employment, town or city of residence, other board positions, and relationships with other business, charitable and governmental entities, and other events, circumstances or conditions that may or may appear to, interfere with their ability to perform their Board or Board Committee duties.

(g) Maintain the confidentiality of all material non-public information about the Corporation, its business and affairs.

(h) Comply with all applicable provincial and federal laws.

(i) Abide by the Employee Code as set out in section 1.4 below.

(j) Abide by all by-laws, codes, policies and guidelines approved by the Board which are applicable to Directors.

1.4 Application of the Employee Code

(1) **Non-management Directors**

Directors of the Corporation will be bound by and comply with all sections of the Employee Code (Appendix A).

(2) **Interpretation**

Unless the context suggests otherwise, in interpreting the Employee Code as it applies to Directors:

(a) The term “Employee” means “Director” or “Board Chair”;

The Employee Code is to be interpreted so as to enhance and supplement the Directors’ Code. Where there is any inconsistency between the terms of the Employee Code and the terms of the Directors’ Code, the terms of the Directors’ Code will prevail to the extent of such inconsistency.

Section 2: Conflict of Interest Policy

2.1 Policy Statement

Directors must avoid situations where their private interests conflict with or may appear to conflict with the best interests of the Corporation or the exercise of good judgment concerning the Corporation. A conflict of interest may arise where:

(a) A Director's personal interests are or may appear to be at odds with the interests of the Corporation; or

(b) A Director, Family Member or Associate receives an improper benefit or advantage as a result of the Director's relationship with the Corporation;

(c) A Director misuses information obtained in the course of acting as a Director or exploits for personal advantage his/her position or relationships with the Corporation for personal gain.

Directors have an obligation to declare any actual, potential, or perceived conflict of interest and resolve it in favour of the Corporation as described in this Policy. This Policy has been adopted by the Board in order to ensure that Directors comply with all applicable legal requirements and follow best practices when dealing with conflicts of interest.

Certain conflict of interest rules apply to Directors under the provisions of the Ontario *Business Corporations Act* (the "OBCA"). This Policy summarizes the OBCA conflict of interest requirements in Section 2.3 below, and sets out additional best practice requirements in Section 2.4 below.

2.2 Definitions

(a) "Associate" means a natural person or Entity with whom the Director has a significant business or personal relationship.

(b) "Entity" means a sole proprietorship, partnership, unincorporated association, unincorporated syndicate, unincorporated organization, trust, or corporation and a natural person in his or her capacity as trustee, executor, administrator, or other legal representative.

(c) "Family Member" means the Director's spouse, the child or parent of the Director or of the Director's spouse, or an individual who resides in the same household as the Director.

(d) "Material Contract" means a material contract or transaction or a proposed material contract or transaction with the Corporation;

(e) "Material Interest or Relationship" means any personal activity, relationship, association, or interest that could be reasonably expected to interfere with the exercise of a Director's independent and impartial judgment, recommendation, or assessment of facts in any given circumstance.

2.3 OBCA Requirements

(1) **Minimum Standards**

The OBCA sets out rules regarding the disclosure of conflicts of interest with which Directors must comply. The Board considers the OBCA rules to be minimum standards which are to be met in addition to the other requirements of this Policy. Under the OBCA, the disclosure procedure described below is to be followed where a Director:

(a) is a party to a Material Contract; or

(b) is a director or an officer of, or has a material interest in, any individual or Entity who is a party to a Material Contract.

The OBCA requirements apply regardless of whether the Material Contract calls for approval by the Board.

(2) **Procedure to Follow**

If a Director has a conflict of interest, the Director must disclose in writing to the Corporation or must request to have entered into the minutes of a meeting of the Board the nature and extent of the Director's interest. Under the OBCA, a Director must make such disclosure:

(a) at the meeting at which the Material Contract is first considered;

(b) if the Director was not then interested in the Material Contract, at the first meeting after he or she becomes so interested;

(c) if the Director becomes interested after a Material Contract is made or entered into, at the first meeting after he or she becomes so interested;

(d) if a person who is interested in a Material contract or transaction later becomes a Director, at the first meeting after he or she becomes a Director;

If the Director does not attend all or any Board meetings, or if the Material Contract does not require Board approval, the Director must disclose in writing to the Corporation or request to have entered in the minutes of meetings of Directors the nature and extent of his or her interest immediately after the Director becomes aware of the Material Contract.

A Director with any conflict of interest must not attend any part of a Board meeting at which the Material Contract is discussed and must not vote on any resolution to approve the Material Contract, except where the Material Contract:

(a) Relates primarily to his/her remuneration as a director of the Corporation; or

(b) Is a policy of insurance for the Director.

ATTACHMENT 1-D

The 2024 EPI Scorecard

Scorecard - Entegrus Powerlines Inc.

8/12/2025

Performance Outcomes	Performance Categories	Measures		2020	2021	2022	2023	2024	Trend	Target	
										Industry	Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		96.91%	97.60%	98.55%	97.48%	97.89%	↑	90.00%	
		Scheduled Appointments Met On Time		99.83%	99.71%	100.00%	99.96%	99.96%	↑	90.00%	
		Telephone Calls Answered On Time		79.11%	81.26%	68.42%	83.75%	76.56%	↓	65.00%	
	Customer Satisfaction	First Contact Resolution		74	85	81	75	75			
		Billing Accuracy		99.81%	99.91%	99.91%	99.95%	99.90%	↑	98.00%	
		Customer Satisfaction Survey Results		93	92	93	94	92			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness		81.00%	78.00%	78.00%	79.00%	79.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	4	1	1	0	1	↓		1
			Rate per 10, 100, 1000 km of line	1.297	0.329	0.311	0.000	0.306	↓		0.384
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.47	1.09	1.76	1.31	1.26	↓		1.42
		Average Number of Times that Power to a Customer is Interrupted [2]		1.18	1.02	1.18	0.93	1.48	↑		1.01
	Asset Management	Distribution System Plan Implementation Progress		112.4	20.2	40.6	61.9	88.4			
	Cost Control	Efficiency Assessment		2	1	1	1	1			
		Total Cost per Customer [3]		$553	$558	$627	$713	$748			
		Total Cost per Km of Line [3]		$11,008	$10,670	$11,977	$13,731	$14,447			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Connection of Renewable Generation**	New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.23	1.06	1.08	1.08	1.35			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.30	1.24	1.25	1.39	1.21			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.19%	9.19%	9.19%	9.19%	9.19%			
			Achieved	8.23%	9.29%	7.85%	8.79%	7.58%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.

Legend:

5-year trend
↑ up ↓ down → flat

Current year
target met target not met

ATTACHMENT 1-E

Concentrix Top-Down Customer Survey

ENTEGRUS

2024 Entegrus
Top Down Report

December 2024

concentrix

Report Overview

1 Key Findings and Performance Updates

2 Service Perceptions

3 Communication and Billing Evaluations

4 Other Insights

5 Summary and Recommendations

concentrix

Overall Insights

- The performance of key metrics remains strong in 2024.
- Entegrus continues to receive high ratings for power quality, customer service, and reliability.
- Business customer ratings for overall satisfaction and power service quality have gradually declined since 2022, whereas residential customer rating for customer service has reached their highest level.
- The bill accuracy metric significantly decreased compared to 2023 for business customers.
- Likelihood to purchase an EV in the next 5 years is at its lowest level since it was surveyed in 2021.

Opportunities

- **Consider Evaluating Pricing Communication Strategies:** Review and adjust pricing communication approaches to address customer concerns, particularly from Business customers.
  - **Prompt and Effective Resolution:** Develop a strategy to address customer billing inquiries and complaints quickly and efficiently. Provide clear, actionable solutions and follow up to ensure customer concerns are fully resolved.
  - **Transparent Billing:** Consider conducting user experience research or piloting a more detailed billing breakdown to help customers understand their energy usage, service costs, and pricing changes.
- Focus on improving services in regions with below-average scores. (e.g., Wallaceburg and St. Thomas).
- **Enhance Outage Communication Systems:** Develop a robust communication plan that includes timely and proactive updates via multiple channels (e.g., email, SMS, social media, website) during outages.
- **Enhance Customer Alerts:** Implement a notification system to alert customers about planned outages or service disruptions in advance. Leverage on customers' preference for electronic communication (e.g., email, SMS) to reduce costs
- **Website Content and Design Enhancement:** Introduce business-focused content that addresses the specific needs and challenges faced by business customers.
  - Simplify navigation for business users by creating dedicated business section or portal that is easily accessible from the homepage.

2024 Satisfaction and Quality Snapshot

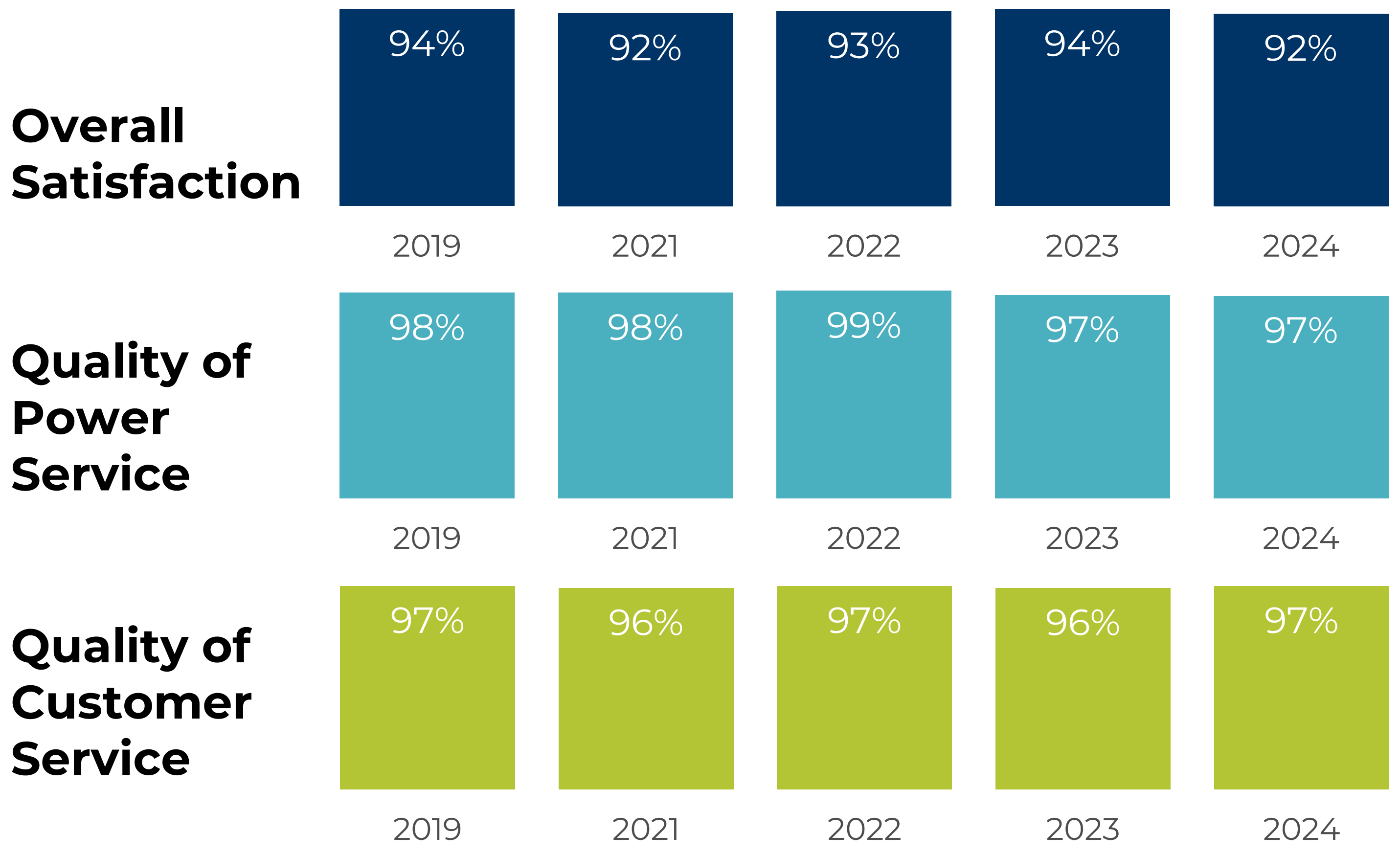
Overall Satisfaction	Quality of Power Service	Quality of Customer Service
92%	97%	97%

Reported as %3-5 (Top 3 Box)

Performance Updates

The performance of key metrics remains steady and strong this year, with a directional dip in overall satisfaction.

Annual Trend of Key Metrics

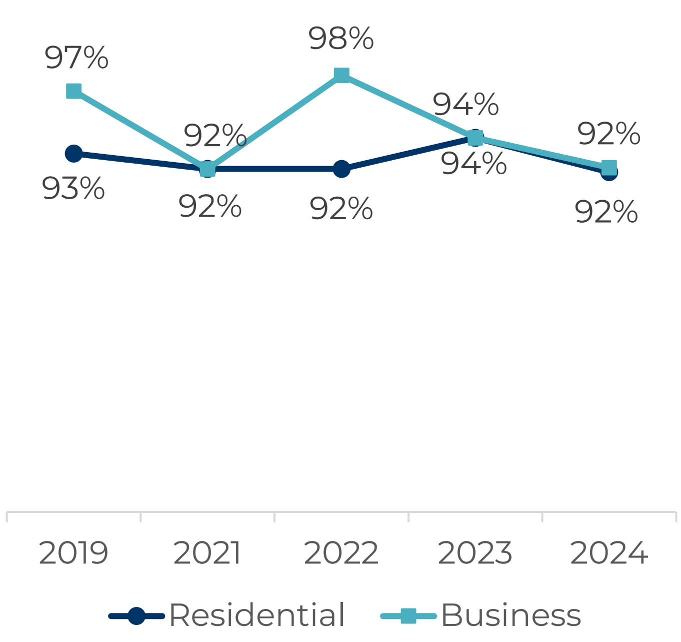


Key metrics are based on Top 3 Box Scores.

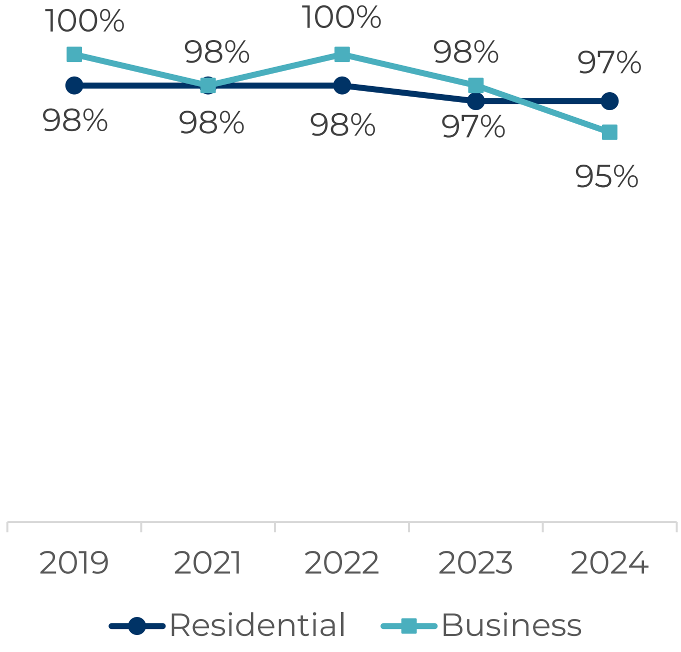
Key Metric Trends – Residential and Business

Overall satisfaction and Quality of Power Service of business customers slipped since 2022. Conversely, residential customers' satisfaction with the Quality of Customer Service improved to its highest point in five years.

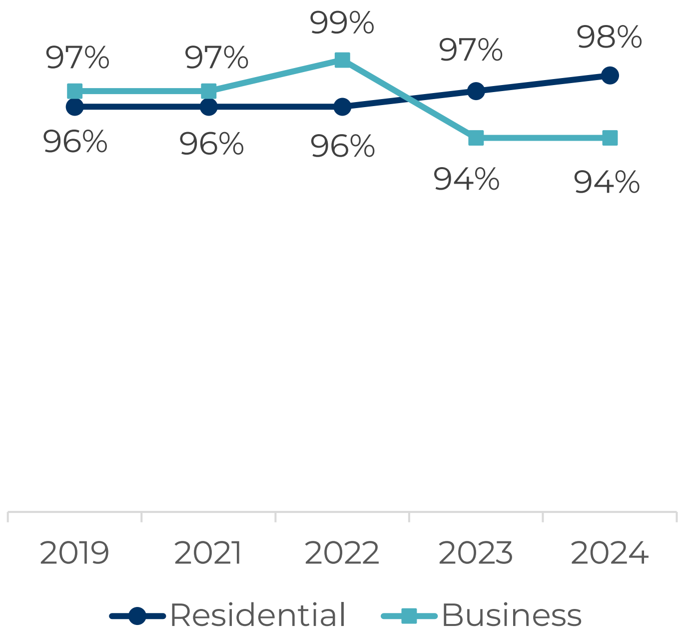
Overall Satisfaction



Quality of Power Service



Quality of Customer Service



Ratings are based on Top 3 Box Scores.

Overall, customers express satisfaction with Entegrus' service reliability, billing, and customer service

Customer Comments about Entegrus

"I never had any problem with them. Whenever I call them for service, they do it immediately. ***People working there are good and very kind****."*

*"****When there is a power outage, they do their best to fix it as soon as possible****. And we have no complaint about hydro."*

"We've had ***no issues with our hydro bill, it is clear and easy to understand****, payments are taken on time."*

"I've never had any issues, never had to call or get any problems resolved - ***everything's been very smooth****. The payment process is very straightforward and if we ever have a disruption of hydro, I know it's out of my control and Entegrus is on it."*

"If I have any concerns or issue, ***someone is always there to explain and answer my questions*** *and I don't have to worry about anything that has to do with the services, and I get updates for my payments."*

"We usually have constant power, ***we haven't had power outages, just blips here and there****. I haven't had any problems with my hydro. It's been good."*

Base: Customers who rated 3, 4, or 5 in Overall Experience question and provided qualitative feedback

Meanwhile, pricing is an area of concern among Business customers, impacting overall satisfaction

Customer Comments about Entegrus

“Prices went up quite a lot for the past 2 years. It's a lot harder financially. They don't offer enough payment flexibility.”

“I requested to suspend billing for an address that is not occupied due to construction, but they insist on sending a charge, claiming they are obligated to do so. I like those bills to be cancelled.”

“Issues with meter not being read correctly and influx in the bill.”

“Paying too much, they charge that I cannot afford.”

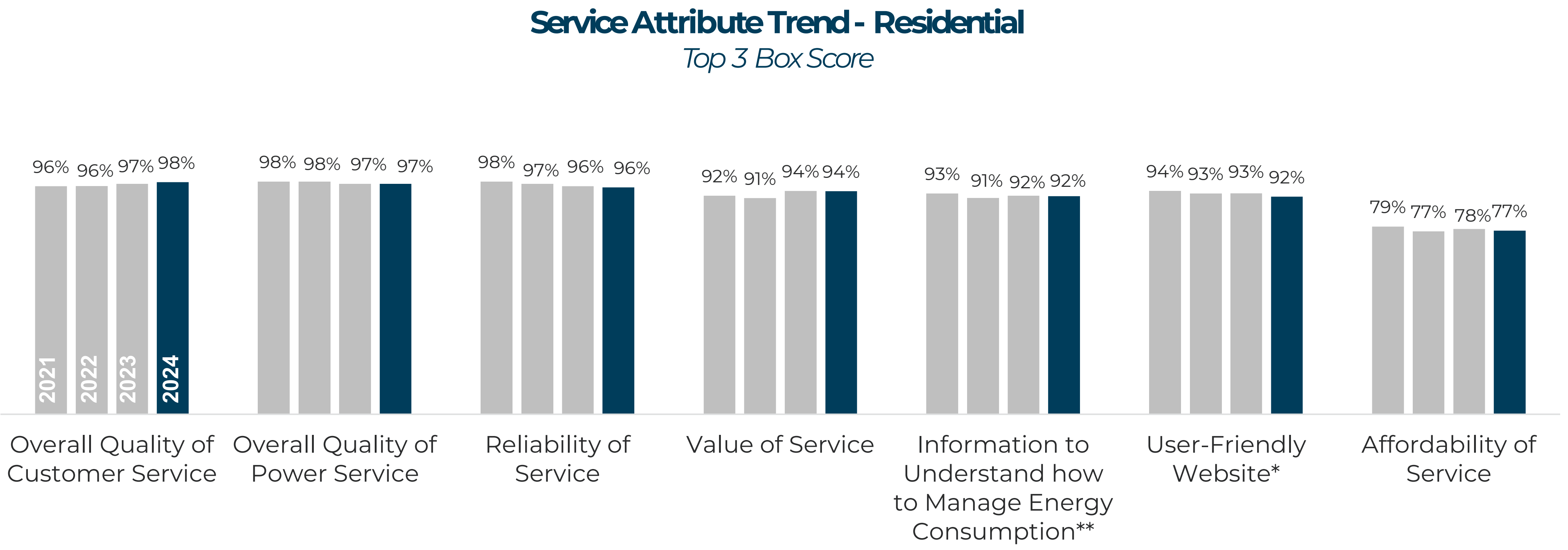
Base: Business customers who rated 1 or 2 in Overall Experience question and provided qualitative feedback:

Service Perceptions

concentrix

High residential service attribute scores were maintained in 2024

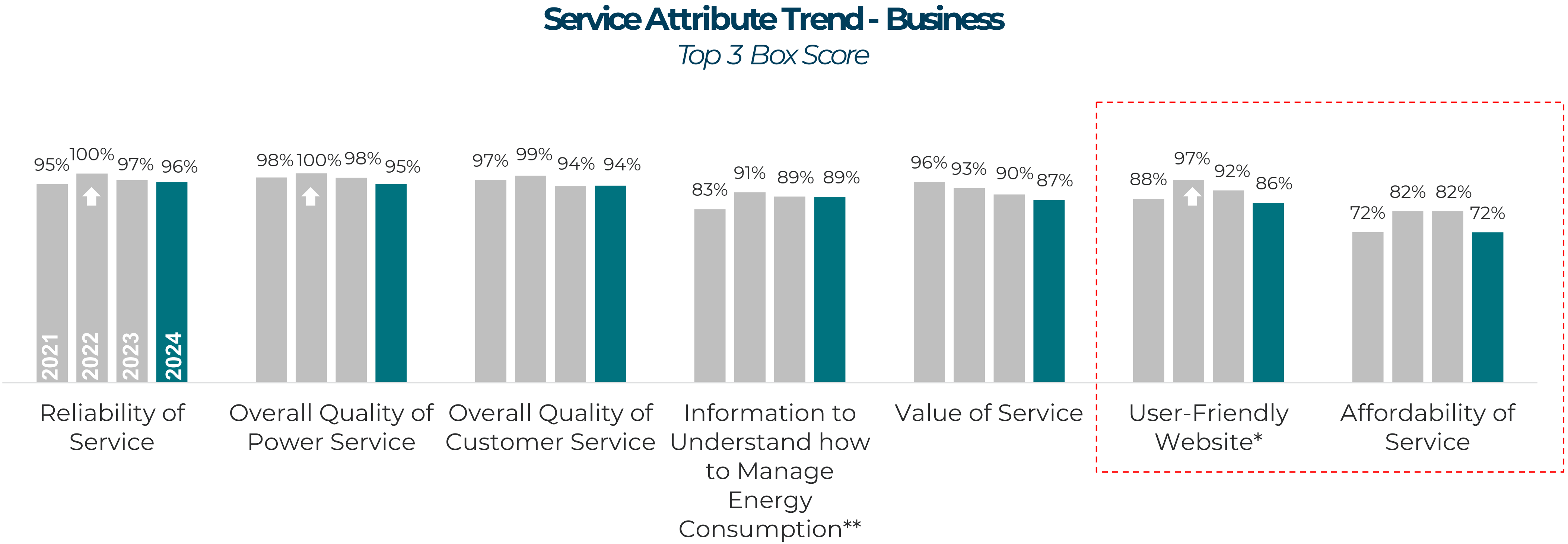
As in previous years, *Affordability* continues to be the lowest-rated metric.



* New attribute added in 2021. ** Attribute wording updated in 2021 – this is rated higher in 2021, but significance is not noted due to wording change.

Most Business service ratings remained consistent

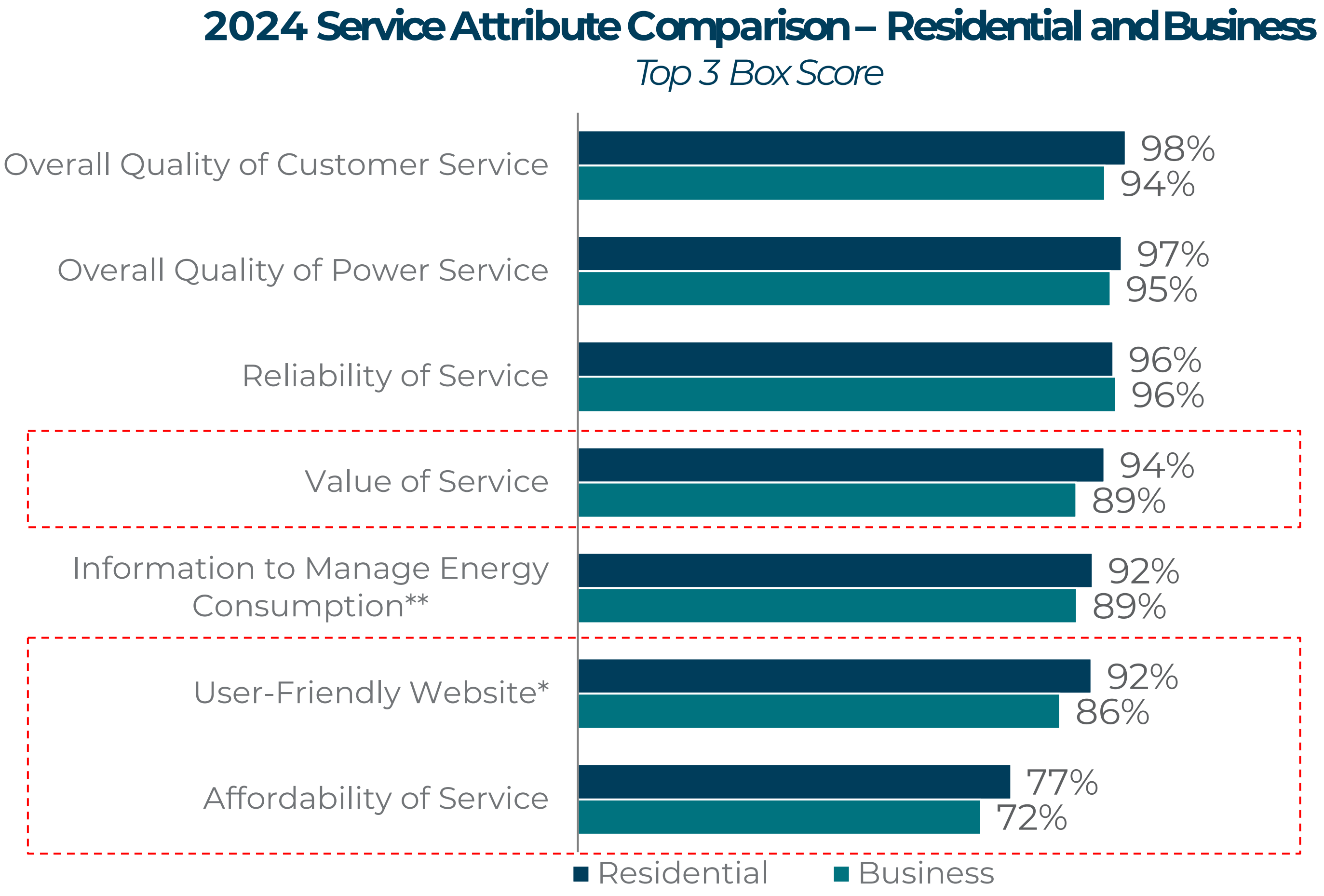
Reliability, service quality, and customer service quality received high ratings. A few business service ratings declined directionally since 2022, primarily a drop in perceived service affordability and website usability.



* New attribute added in 2021. ** Attribute wording updated in 2021.
Arrows represent a significant difference from the previous year.

Service Attribute Scores - Residential and Business

Both business and residential customers give high ratings for customer service quality, power service quality and reliability. But business customers tend to be more critical.



The largest differences between business and residential customers are found in the user-friendliness of the website, as well as in the perceived value and affordability of services.

* New attribute added in 2021. ** Attribute wording updated in 2021.

Customers share satisfaction with the service, despite concerns on the service cost

Customer Comments about Value and Affordability

"Cause the service is good, they help when I call about questions and stuff, but its hydro costs a lot."

"Cost increase. Other than that, the service has been good."

"I don't think I could be very satisfied. Services are great, but the cost is not."

"I'm satisfied but we have some outages. The costs are going up."

"Pretty seamless, everything makes sense. Wish services were a little less expensive."

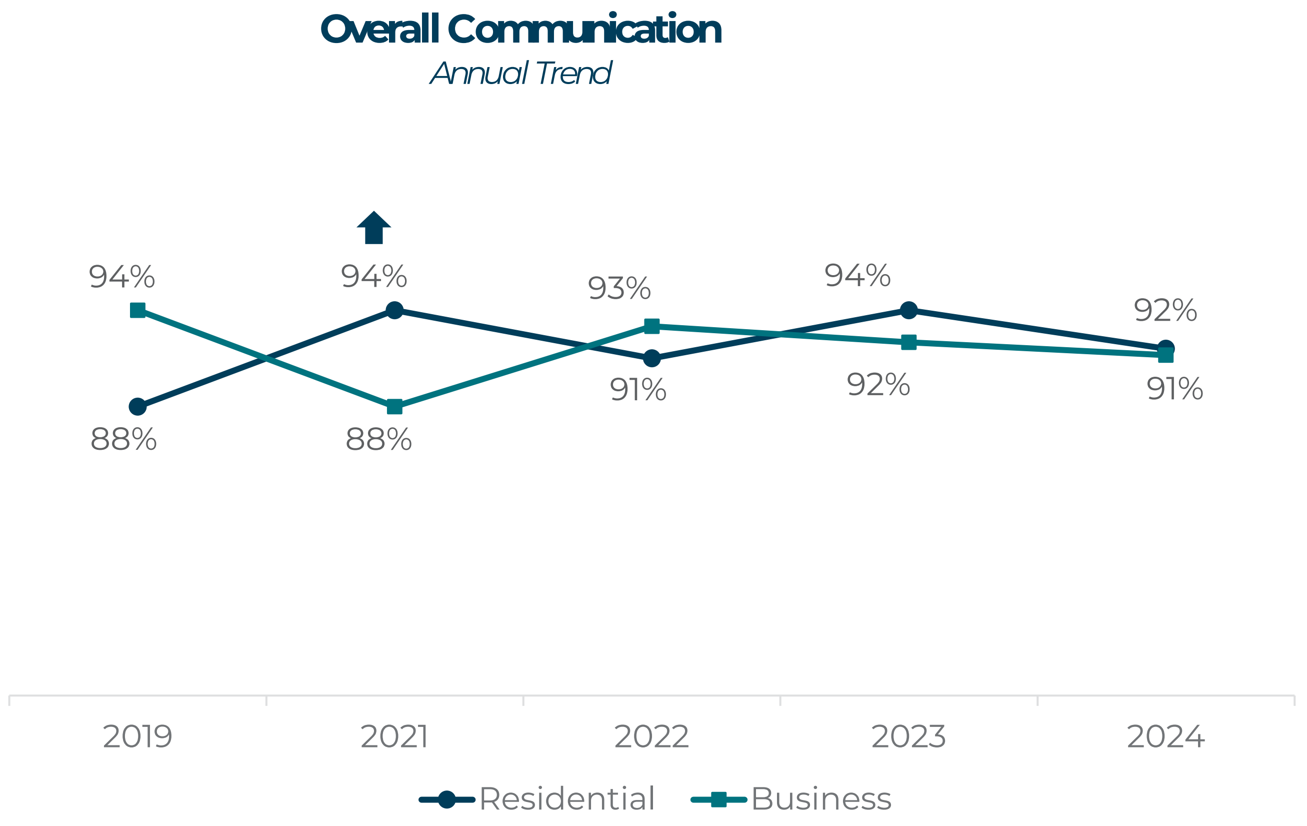
"The cost is a concern and there's a number of times that our hydro flicks off."

"Bills are very expensive, hydro goes out quite a bit, appreciate outage notices but Sundays are difficult for people at home, understand that they do not want outages will affect businesses."

Communication and Billing Evaluations

Overall Communication Trend

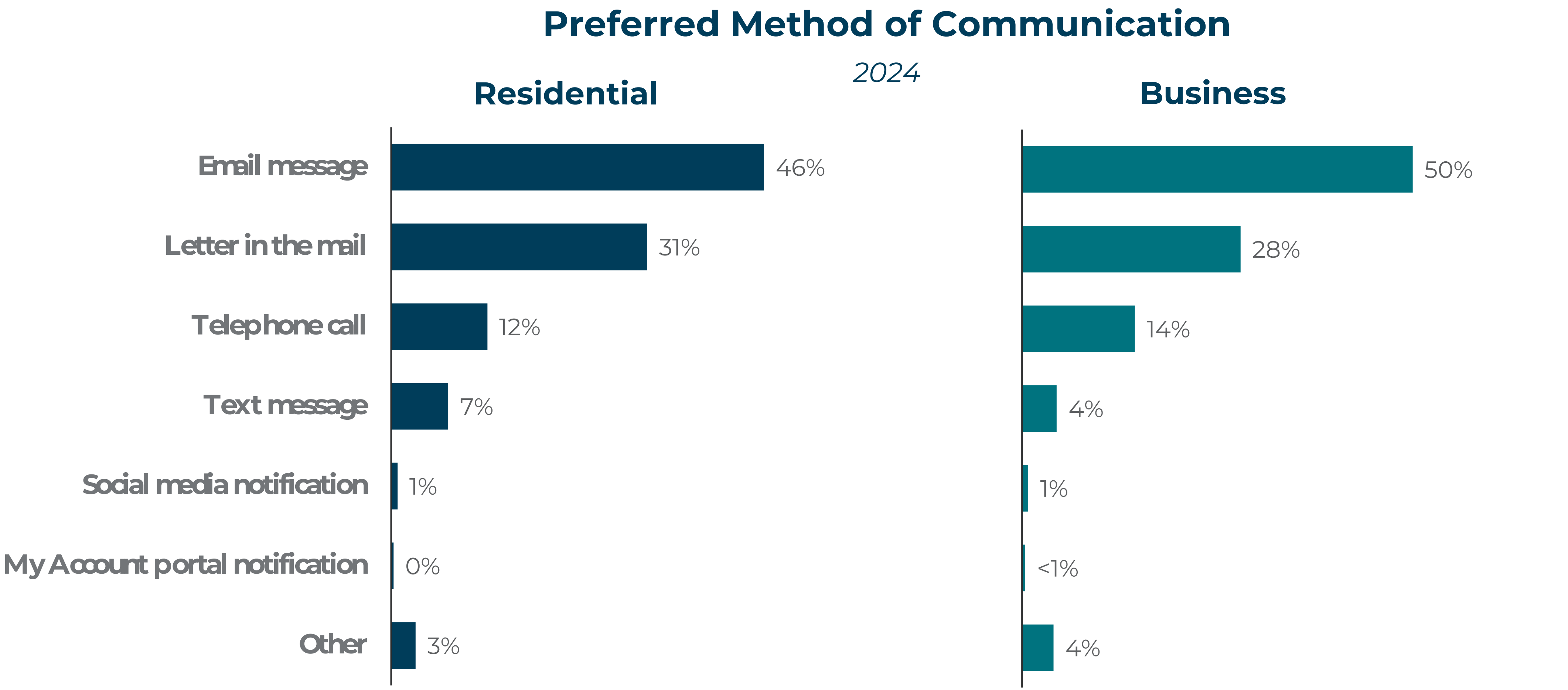
Ratings on *communication* remain relatively stable for both Residential and Business customers this year.



Overall Communication Trends are based on Top 3 Box Scores.
Arrows represent a significant difference from the previous year.

Email continues to be the most favored method of communication

The second choice for both residential and business customers is receiving letters in the mail.



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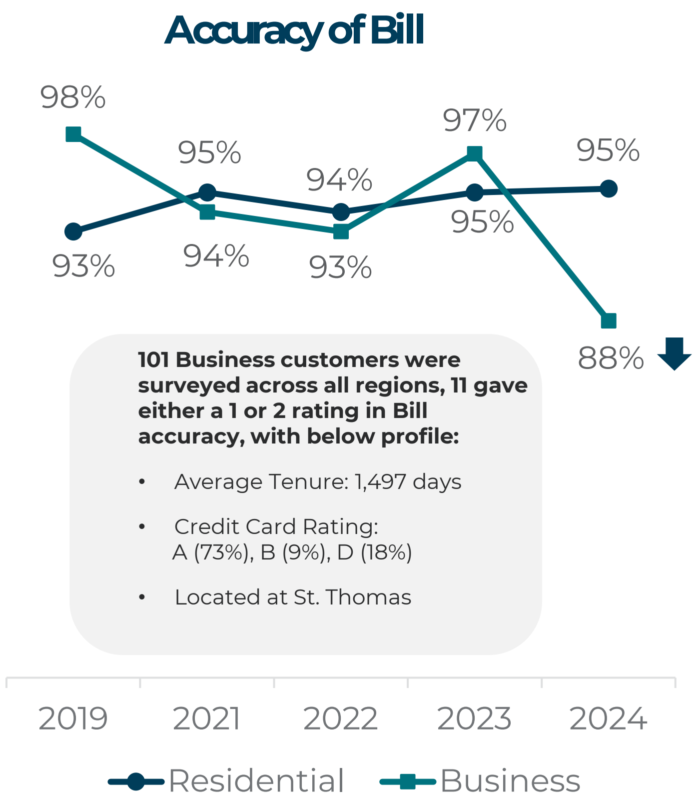
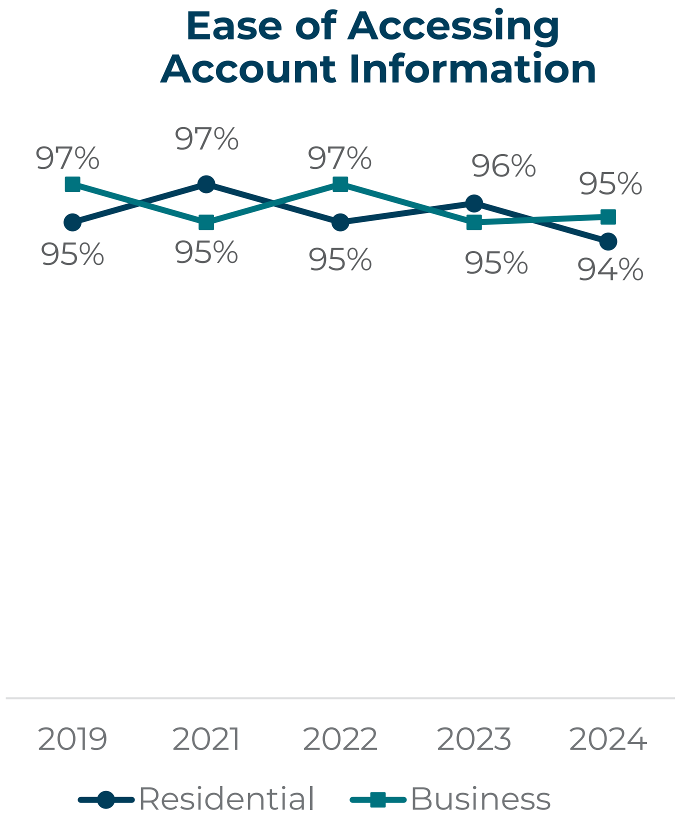
Billing Trends – Residential and Business

Ease of accessing account information remains steady. Business customers report a significant decline in bill accuracy, with the low raters primarily coming from the St. Thomas region.



101 Business customers were surveyed across all regions, 11 gave either a 1 or 2 rating in Bill accuracy, with below profile:

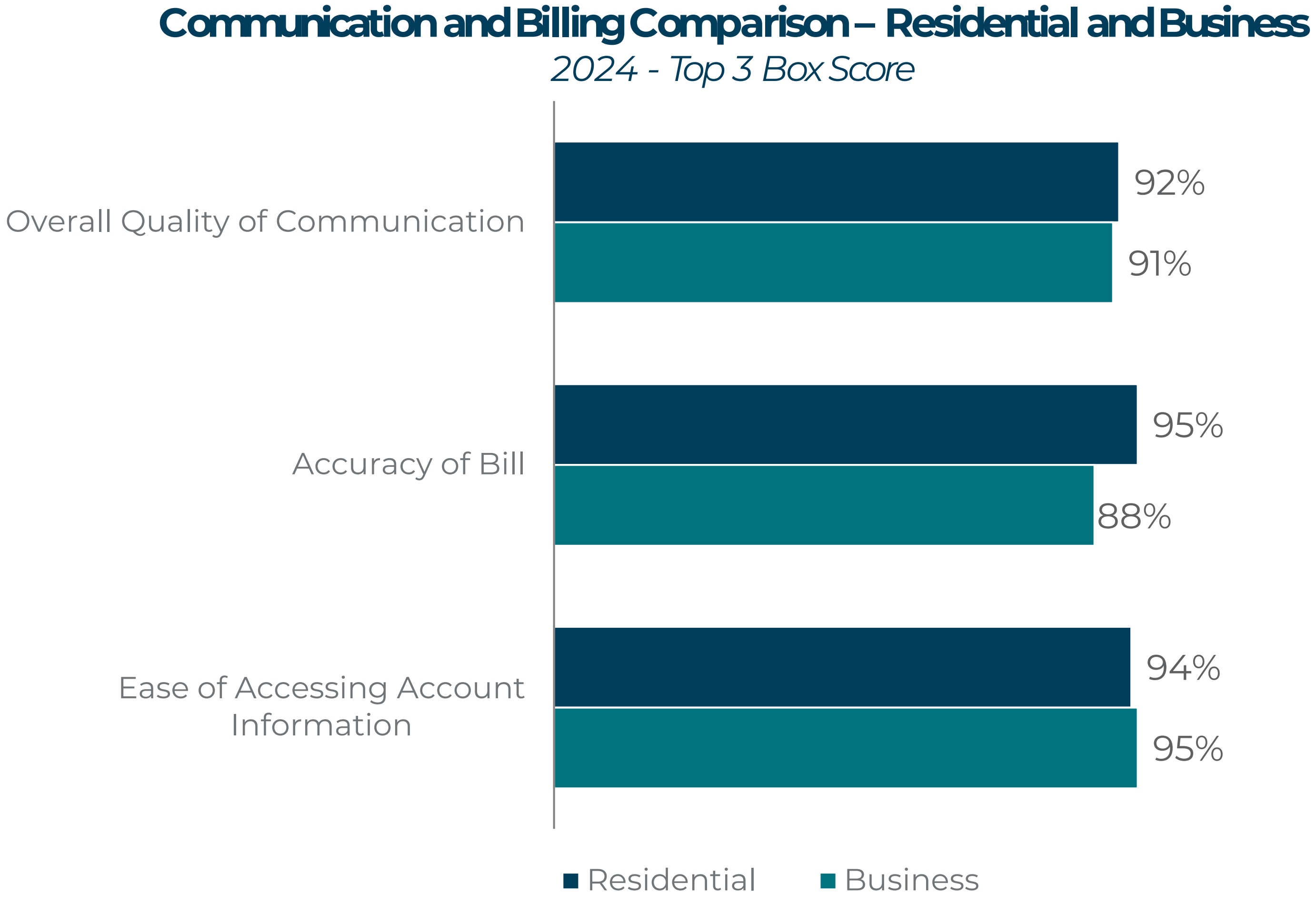
- Average Tenure: 1,497 days
- Credit Card Rating: A (73%), B (9%), D (18%)
- Located at St. Thomas



Billing Trends are based on Top 3 Box Scores. Arrows represent a significant difference from the previous year.

Communication and Billing – Residential and Business

Both business and residential customers have positive and comparable perceptions of communication quality and ease of accessing information. Business customers rate billing accuracy 7 points lower than residential customers.



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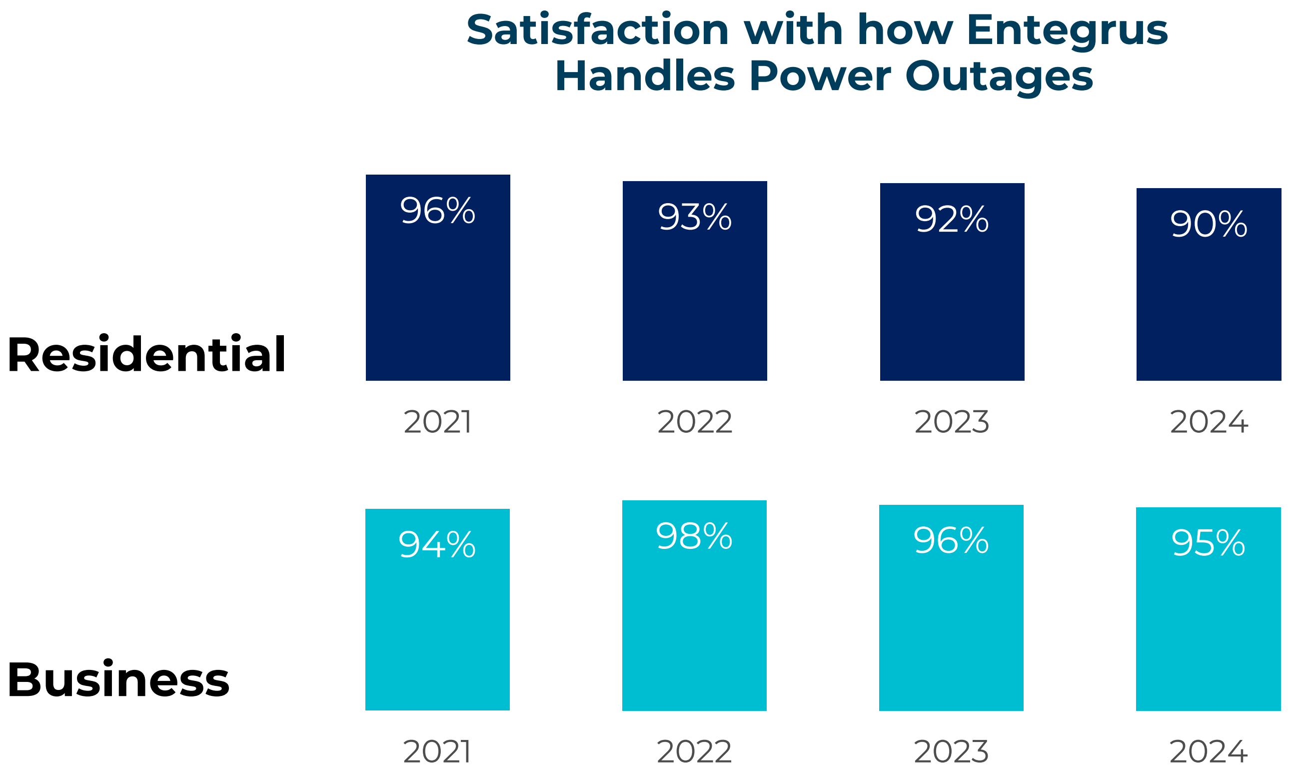
Other Insights

Satisfaction with Power Outage Handling

While satisfaction with Entegrus' handling of power outages or interruptions remains strong, it has gradually declined since 2022 among both residential and business customers.



Satisfaction is based on Top 3 Box Scores. New question added in 2021.

Power outage feedback is generally positive with some points for improvement on communication

Customer Comments about Power Outages

Timeliness and effectiveness of Response to outages

*"We experience very few interruptions at all. The **few we have had have been dealt with in a very short period of time**."*

*"I think **they're always right on top of the power outage** and we don't have to wait that long to have our power back on."*

*"Because they are very clear of how the power outage is in your area, and **they are very quick to get it back up and running**."*

Communication and updates during outages

*"I just **wish there was more timelines provided**. The power eventually comes back on. It could be in two hours, seven minutes, etc. **(Wish) there was more communication on how long it's going to be out**."*

*"A couple times it has gone out and I **haven't received any information**, so it takes time to find out what has happened and how much longer before we get it back"*

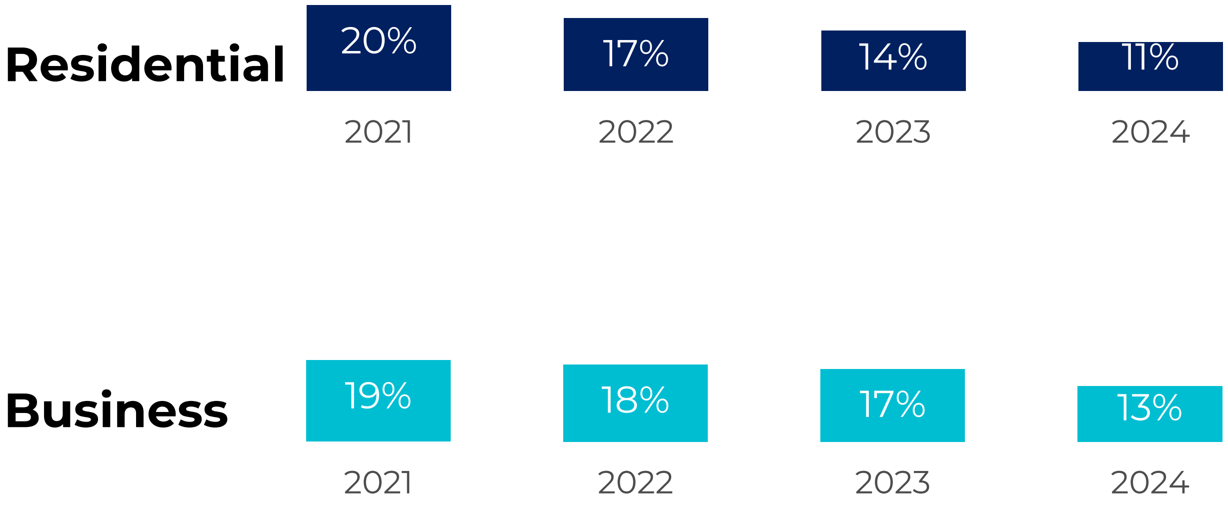
*"Just for the fact that sometimes there isn't great communication. We **have to dig on information about them to even find out about power outages**."*

Base: Customers who rated 4 or 5 in Power Outage Handling question and provided qualitative feedback: n=353. Does not include blank responses.

Likelihood to purchase an electric vehicle

The likelihood of purchasing an EV in the next five years has hit a 4-year low since it was first surveyed in 2021, primarily due to concerns about cost, reliability, and infrastructure availability.

Likelihood to Purchase an Electric Vehicle in Next 5 Years



"We would love to have an electric vehicle when it's affordable but right now they're way too costly."

"I don't know the reliability. There's bugs in it and I would like them to work out the bugs and make it a heck of a lot cheaper..."

"Don't believe that's there's the infrastructure to own an electric vehicle in our area at this time."

"Don't want electric vehicle because batteries cost too much money..."

"I don't think the power grid can sustain the amount of electricity needed for the service and charge the vehicle if everyone will have electric vehicle. I personally don't think that electric vehicle will not going to take off in the next 5 five years."

Likelihood is based on Top 2 Box Scores. New question added in 2021.

2024 Regional Scorecard

2024 Scores (% Top 3 Box) – By Region		Total	Kent	Strathroy	Chatham NW	Chatham SE	Wallace - burg	St. Thomas
	Base	*505*	*113*	*34*	*105*	*92*	*44*	*89*
Overall	Overall Experience	92%	91%	91%	92%	92%	86%	92%
Service Attributes	Overall Quality of Power Service	97%	94%	100%	99%	97%	98%	96%
	Reliability of Service	96%	92%	97%	97%	97%	93%	97%
	Overall Quality of Customer Service	97%	98%	100%	100%	95%	95%	93%
	Value of Service	93%	93%	94%	94%	95%	93%	88%
	User-Friendly Website*	90%	93%	95%	93%	89%	83%	86%
	Information to Manage Energy Consumption**	91%	92%	97%	95%	87%	93%	89%
	Affordability of Service	76%	79%	85%	78%	73%	72%	70%
Communication	Overall Quality of Communication	92%	93%	88%	92%	93%	83%	91%
Billing	Ease of Accessing Account Information	94%	95%	100%	94%	94%	89%	96%
	Accuracy of Bill	94%	95%	100%	95%	95%	95%	87%

Shaded area represents a Potential Opportunity (Score is 5% or more lower than Total)

Please note Elgin, Middlesex and St. Thomas Outer are not shown due to small base sizes (<30).
* New attribute added in 2021. ** Attribute wording updated in 2021.

Thank you

Let’s do something great

Appendix

2024 Customer Profile Data

Customer Tenure	Volume	OSAT *(% Top 3 Box)*	Credit Rating	Volume	OSAT *(% Top 3 Box)*
< 1 year	10%	96%	A	88%	93%
1< 5 years	29%	89%	B	<1%	*
5 < 15 years	29%	92%	C	1%	*
15 < 20 years	10%	98%	D	9%	79%
20 or more years	23%	91%	E+F	<1%	*

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* Please note data is not shown due to small base sizes (<30).

Study Overview

Objectives

- The main objective of the study is to measure customer satisfaction in the areas of service, brand performance, communication and billing with Entegrus.
- A secondary study objective is to document satisfaction metrics for the OEB and scorecard reporting.

Survey Statistics

- A total of 505 surveys were completed in 2024 - 404 residential and 101 business surveys.
- Where applicable, scores have been statistically tested with prior years at the 95% confidence level.

Methodology

- A telephone methodology was used for this study.
- The survey was in field from October 29 to 31, 2024.
- Data collection has been conducted in Canada since 2021.
- Please note that the Top Down study was not completed in 2020 due to COVID.

ATTACHMENT 1-F

Concentrix Transactional Customer Survey

ENTEGRUS®

2024 Entegrus
Transactional Report

December 2024

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Report Overview

1 Key Findings and Performance Updates

2 Representative Evaluations

3 Call Handling Trends

4 Call Reason Insights

5 Appendix

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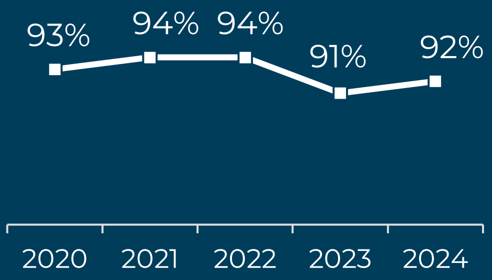
Overall Insights

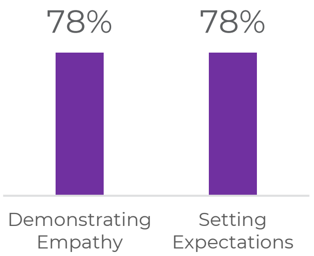
Overall Satisfaction
(Top 3 Box)



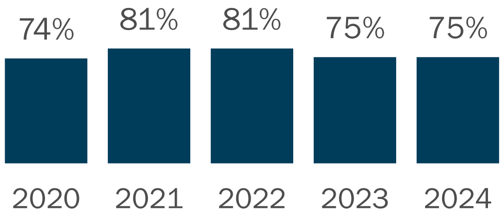
- Both overall satisfaction and representative satisfaction improved compared to last year, indicating positive developments in customer service.
- Call satisfaction levels were maintained over the past year.
- All representative attributes saw improvement from last year, with the highest ratings in courtesy and the lowest in setting expectations and demonstrating empathy.
- First contact resolution remained consistent.
- There was a notable increase in general inquiries related to billing.

Opportunities

Rep Performance
2024 Rating of 'Excellent'



First Contact Resolution
Trend



- **Empower Representatives:** Equip representatives with additional resources and authority to resolve a broader range of customer issues during the initial interaction, which may improve first contact resolution rates.
- **Enhance Training Programs:** Identify opportunities to further improve the lowest-rated representative attributes – specifically, setting expectations and demonstrating empathy.
  - **Set Clear Expectations:** Examine how to establish clear and realistic timing expectations for follow-ups and callbacks with customers.
  - **Role-Playing and Workshops:** Implement role-playing scenarios and empathy training workshops.
  - **Call Critique:** Consider reviewing customer calls by listening to recordings of both well-managed and poorly-handled calls. This can effectively illustrate concepts like empathy and problem solving.
- **Proactive Outreach:** Initiate programs to proactively contact customers who have had billing inquiries or service cancellations, to fully understand their concerns.
- **Targeted Campaigns:** Consider campaigns aimed at understanding customer needs during new account activations and service cadncellations.

2024 Satisfaction Snapshot

Overall Satisfaction

92%

Call Satisfaction

95%

Rep Satisfaction

98%

Reported as %3-5 (Top 3 Box)

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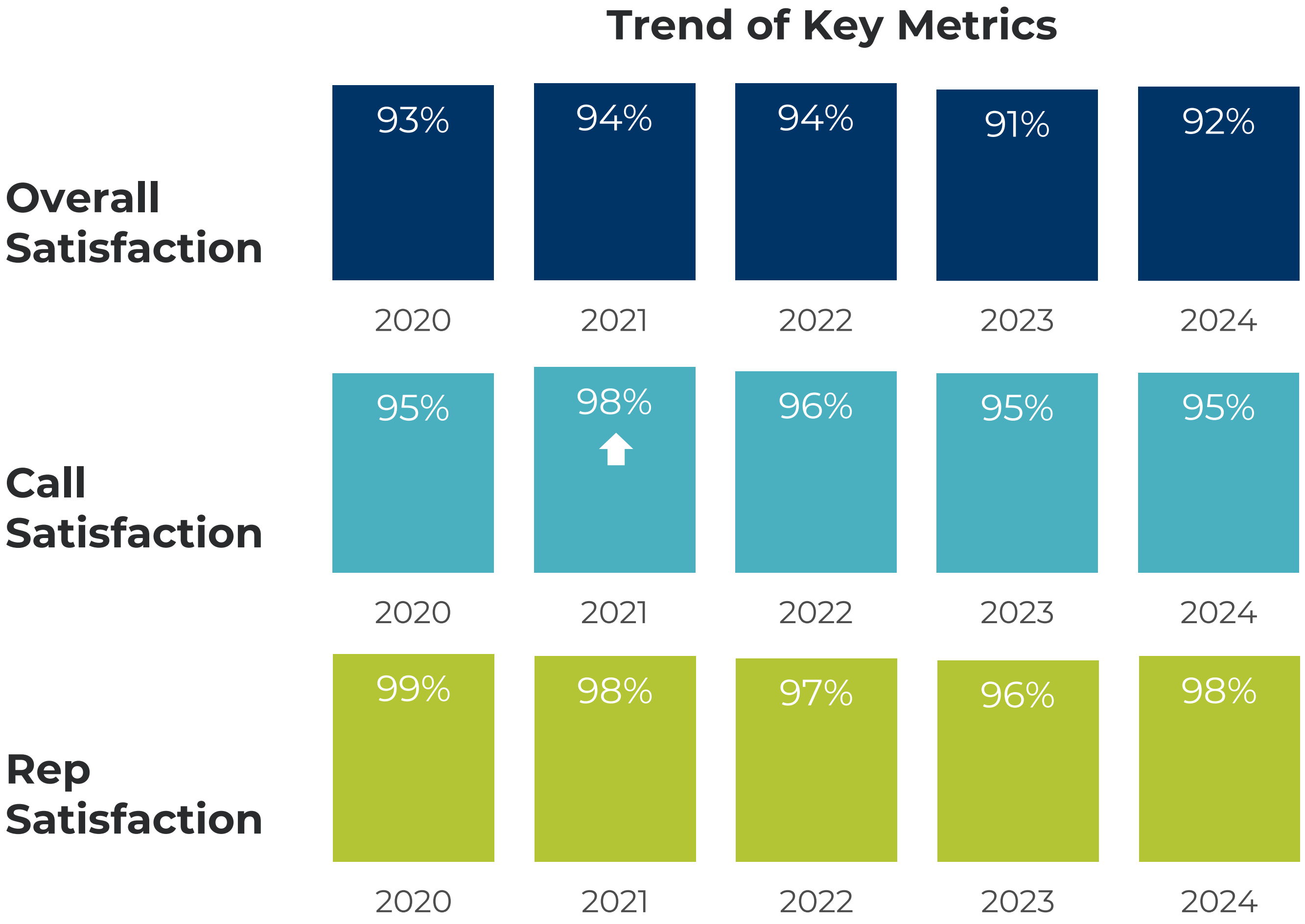
Performance Updates

Overall Satisfaction and Rep Satisfaction are slightly higher this year. Call Satisfaction remained steady with 2023.

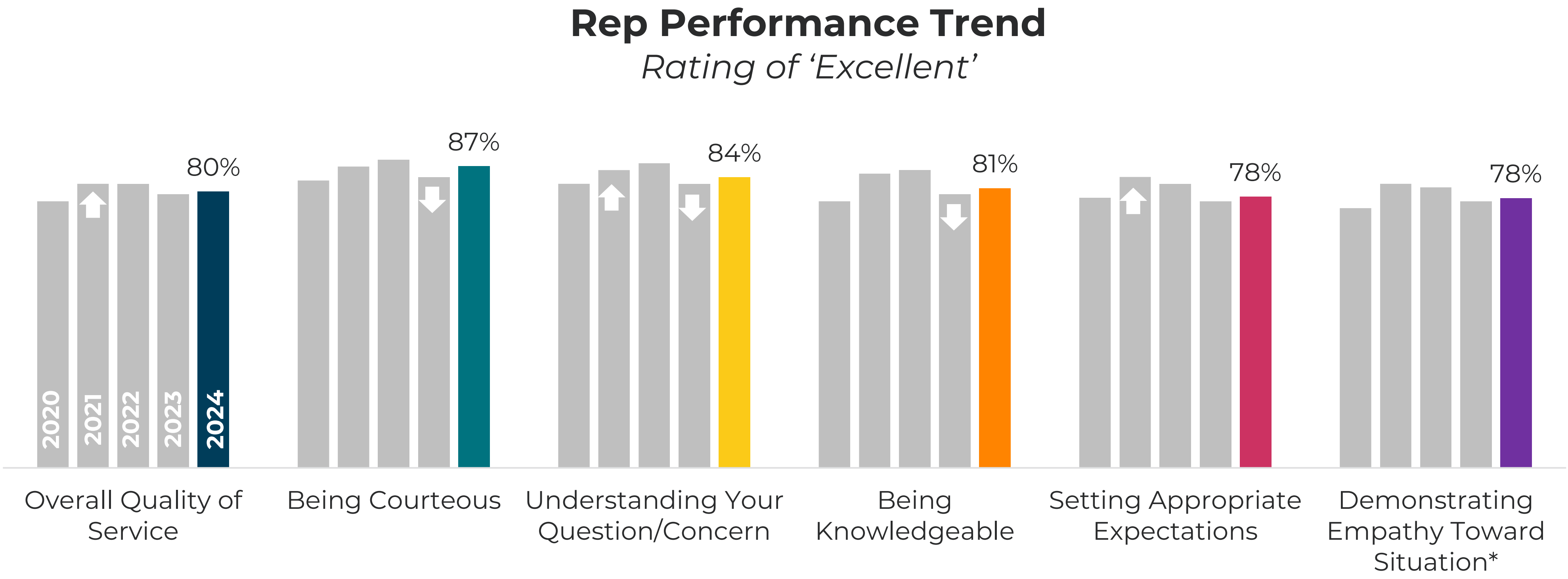


Key metrics are based on Top 3 Box Scores.
Arrows represent a significant difference from the previous year.

Representative Evaluations

Rep performance is slightly higher this year

All representative attributes improved since last year, with the highest scores in courtesy and the lowest in setting expectations and showing empathy.



* Attribute added in 2020.
Arrows represent a significant difference from the previous year.

Representatives receive positive feedback, despite certain concerns being beyond their control

Customer Comments

about

Representatives

"Very knowledgeable, very respectful… it's just they couldn't fix the problem, it was an outstanding bill that needs to be paid off."

"Reps understand the problem and they transferred my call."

"They answered all my questions, and they were able to direct me what to do, and everything went really smooth."

"They were very kind, they listened, and they answered my questions."

"They were caring, compassionate, empathetic, and extremely knowledgeable. They put my mind at ease."

"They were very personable. They understood what I was asking. They gave me very concise answers. They made the call very quick and easy."

"They were very respectful to my situation and very knowledgeable of what to do."

"The person I spoke to was extremely nice, straight to the point, and understanding. Normally, the phone calls are pretty good."

Call Handling Trends

Trend of Call Handling Metrics

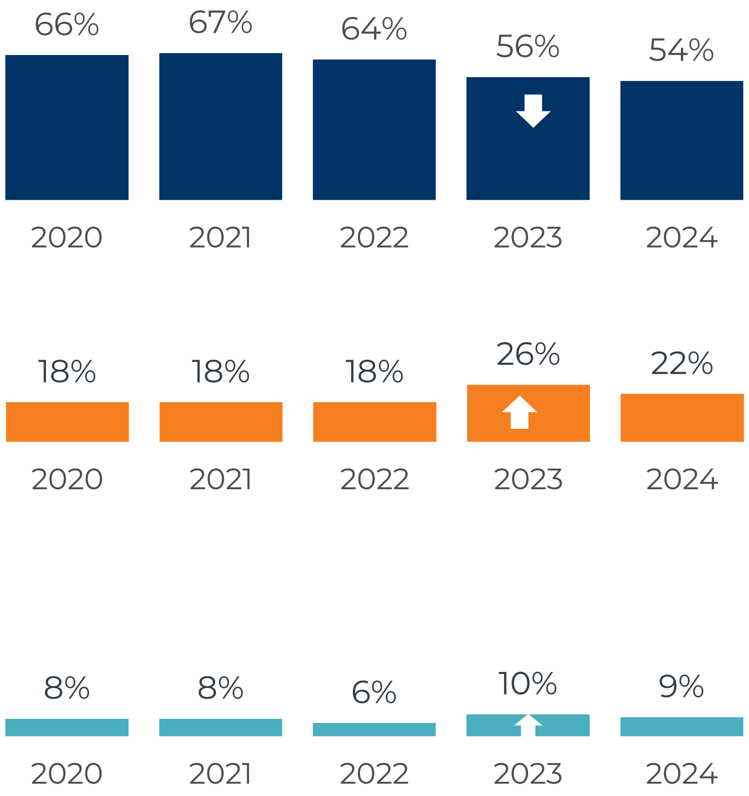
The percent of “no effort” calls slightly decreased this year, attributed to a relatively higher rate of holds and transfers compared to previous years.

Customer Effort Level

(% No Effort*)

Holds

Transfers

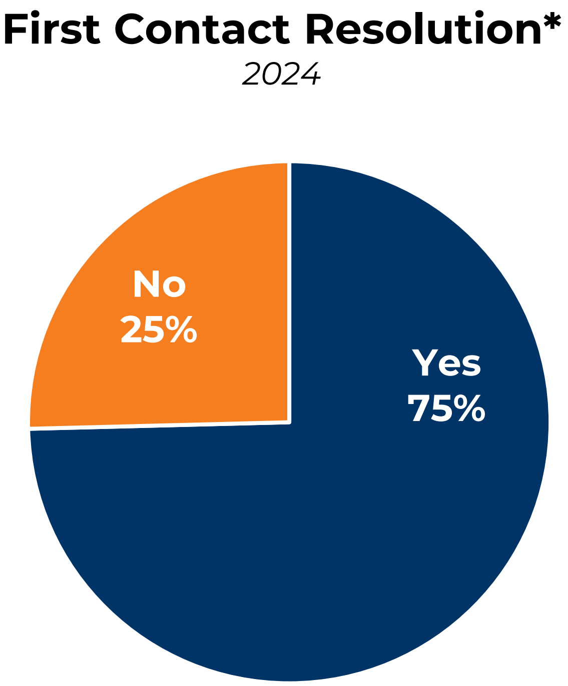


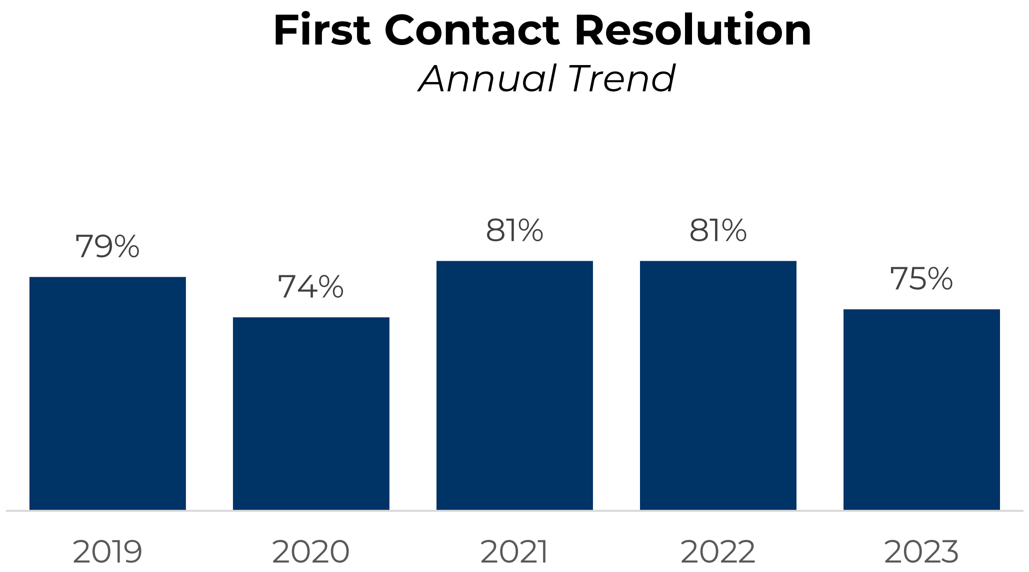
Customer Effort Level	Overall Satisfaction *(Top 3 Box)* When...
No Effort	97%
Low Effort	90%
High Effort	72%

Arrows represent a significant difference from the previous year.
*No effort calls refer to situations where the customer’s issue is resolved without any holds or prior contacts being necessary

First contact resolution remained consistent

3 in 4 report resolution on the first contact in 2024





- FCR includes only hydro-related calls. Calls related solely to water are excluded following a verification process that involves call listening by Entegrus.

In 2024, FCR is lowest for *incorrect bill*, *previous bill too high* and *report outage* calls; however, use caution as base sizes are small for these call types.

- The FCR definition was updated in 2021 to exclude those who said they attempted resolution via phone before calling.

Impact of FCR on Performance

Overall Satisfaction with Entegrus, Call Satisfaction, and Rep Satisfaction weaken when the concerns of customers are not resolved at first contact.

When concerns have been **RESOLVED AT FIRST CONTACT**

FCR

97%	99%	100%
Overall Satisfaction	Call Satisfaction	Rep Satisfaction
vs. Total 2024: 92%	*vs. Total 2024: 95%*	*vs. Total 2024: 98%*

When concerns have **NOT BEEN RESOLVED AT FIRST CONTACT**

Non-FCR

81%	89%	95%
Overall Satisfaction	Call Satisfaction	Rep Satisfaction
vs. Total 2024: 92%	*vs. Total 2024: 95%*	*vs. Total 2024: 98%*

"They sent me to customer service for scheduling, nobody answered so I left a message, and nobody called me back."

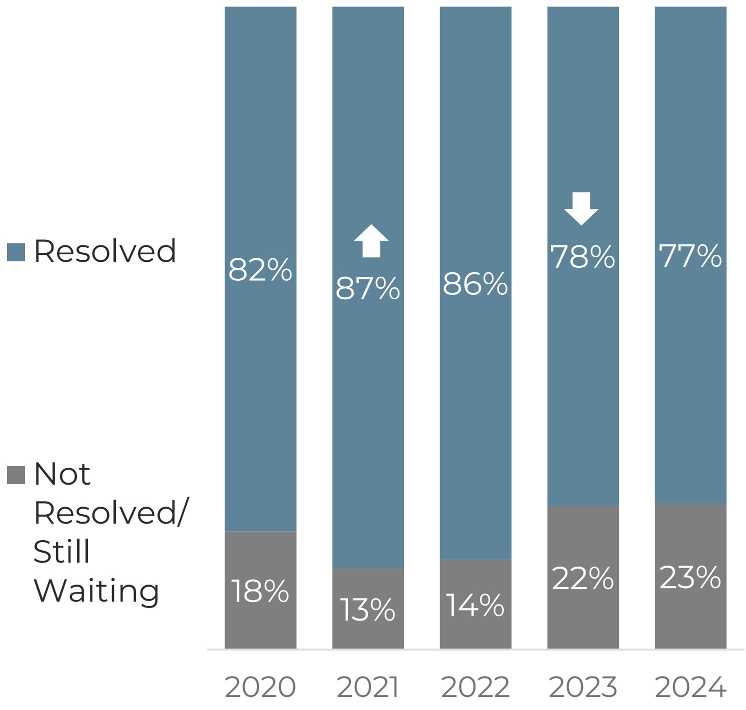
- Non-FCR customer, B2B in Overall Satisfaction

Reported as %3-5 (Top 3 Box)

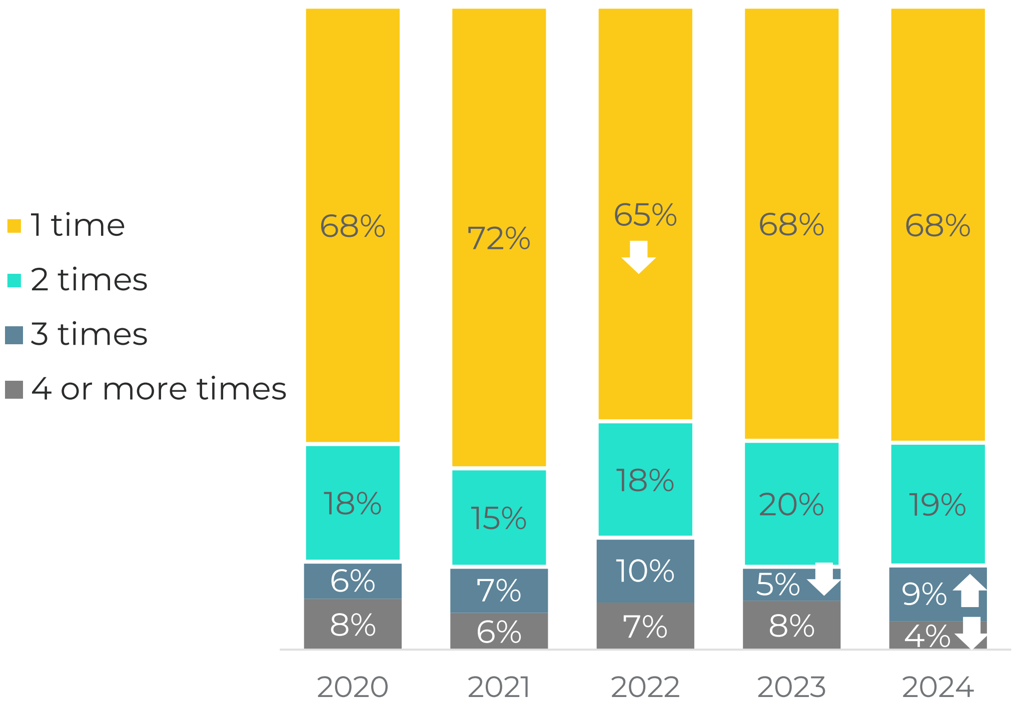
Ease of Resolution

Resolution rate and the frequency of customer calls within the past six months remained relatively stable from 2023.

Issue Resolution



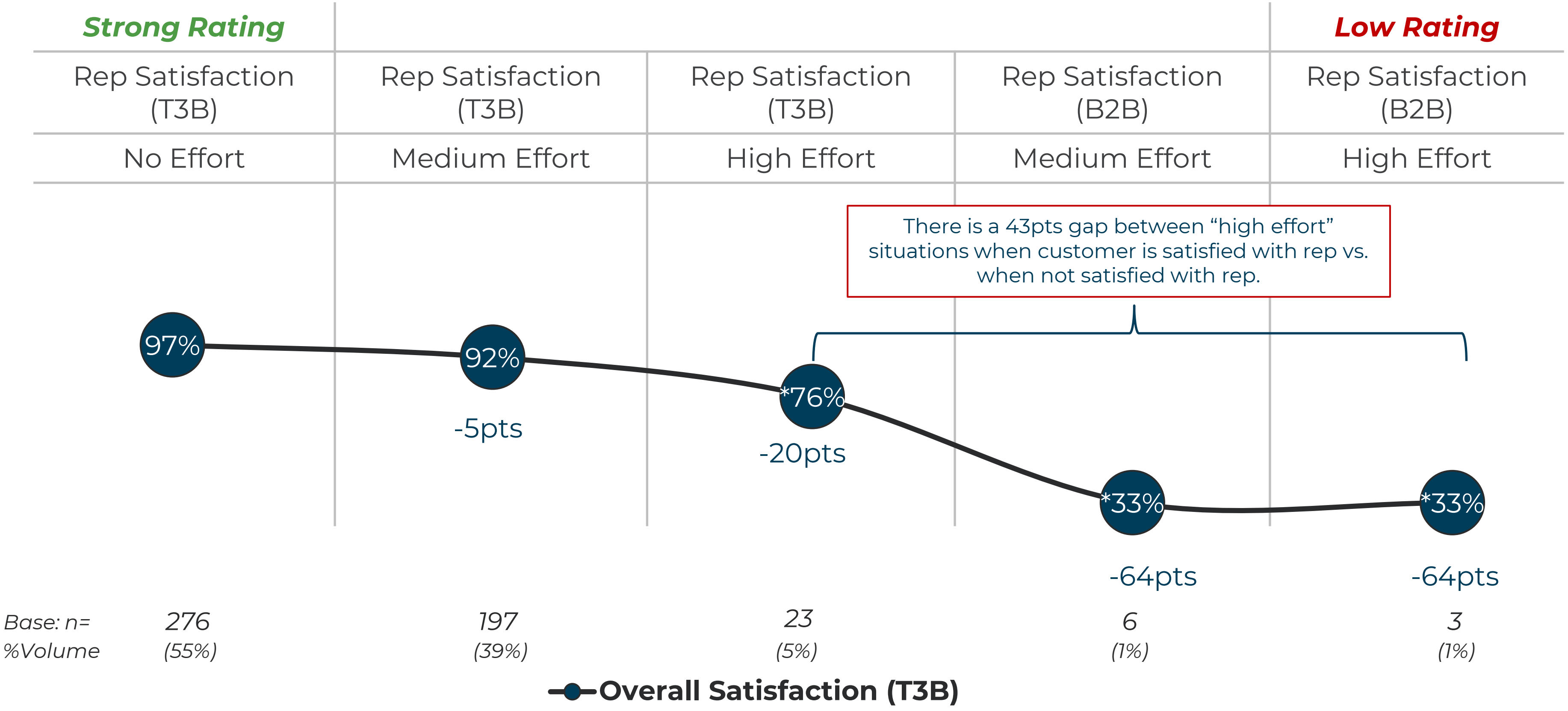
Number of Times you Called in P6M



Arrows represent a significant difference from the previous year.

In high-effort situations, Reps can "save" an interaction with strong performance

For 55% of the calls, Entegrus achieves both rep satisfaction and no effort, indicating that reaching this high standard is feasible



- *Base size < 30. Interpret with caution
- View on Rep Sat (B2B) and No Effort is not shown since n=1 only
- Note: Don't know, Refused and NA are excluded from this analysis

Review customer feedback to pinpoint opportunities for improving resolution process

Customer Comments

About Resolution

“It was answered quickly and accurately. My issue was resolved right away.”

“Because I got all the information, whatever I need, and whatever I was not aware of. They guided me to the correct portal, so I was satisfied with the response. Whatever my issue was, they resolved the issue.”

“Because I called, and they didn't have one person in the office to handle customer service for the day. That ended up costing me a couple of days of progress.”

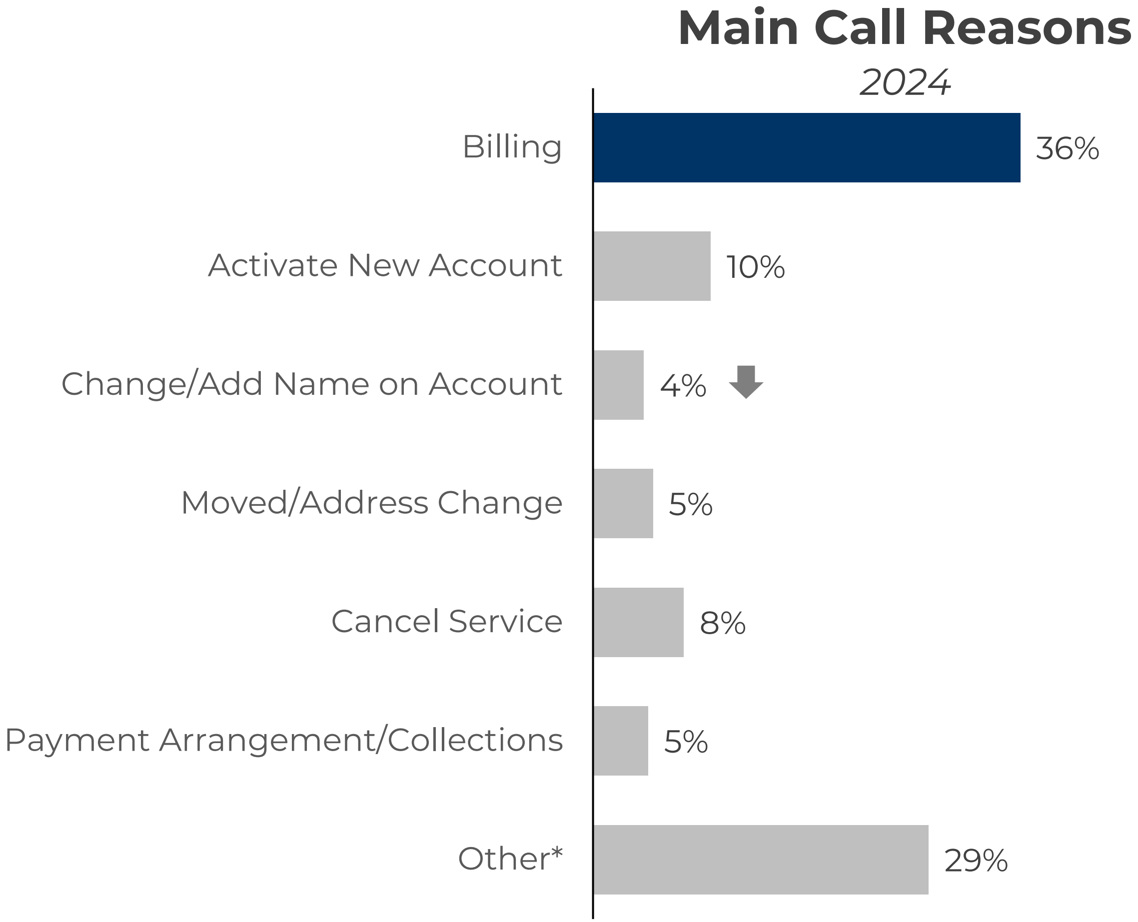
“We moved and contacted to shut the services off, and they weren't shut off and we received a bill for 140 dollars. When I asked how to resolve this issue, they said to send an email, there is no one to talk to.”

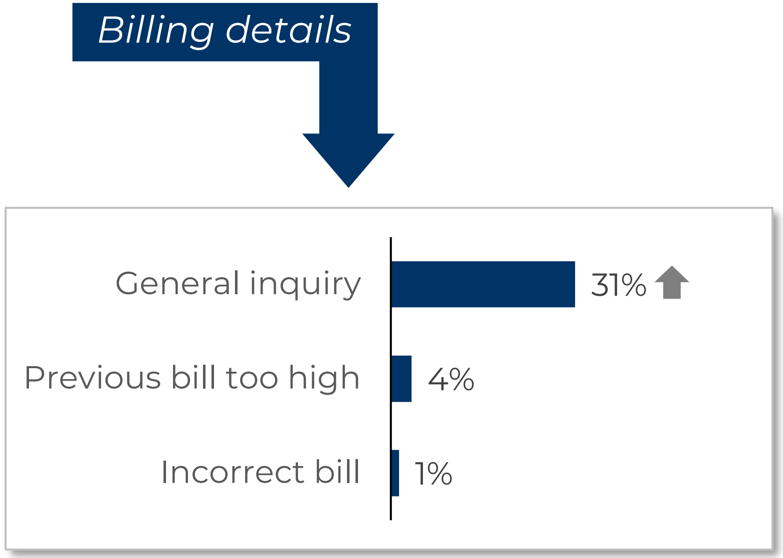
Feedback among those who rated B2B in Overall Satisfaction

Call Reason Insights

Highest volume of calls relates to billing issues

General inquiries on billing notably increased from last year. Others call for new account activations and service cancellations





* Other reasons comprise miscellaneous comments.
Arrows represent a significant difference from the previous year.

Insights into billing inquiry calls

Representatives have shown improvement in demonstrating empathy, setting expectations, and resolving general billing inquiries in 2024.

	2023	2024
Survey Volume	*25%*	*31%*
Overall Satisfaction (Top 3 Box)	94%	95%
Overall Rep (Excellent)	84%	84%
Demonstrating Empathy (Excellent)	**78%**	**81%**
Setting Expectations (Excellent)	**82%**	**85%**
Resolution (Yes)	**81%**	**87%**

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Balancing Benefits and Costs: Customers praise utility initiatives, but express concerns over rates and billing confusion

Customer Comments about Billing, Fees, and Payment

“I'm happy that they allowed me to connect my solar panel system to the grid. I think that will benefit me in the long run and will benefit society as well. I'm glad they're letting people participate in that way.” – Hydro-related inquiry

“I just find their rates are high but everywhere is high nowadays.” – Hydro-related inquiry

“They are always keeping us aware of various options with their brochures, they are always keeping me aware of different pricing available.” – Hydro-related inquiry

“The cost is too high and also, I feel like when I call, I don’t get as much information or the response I was looking for.” – Both water and hydro-related inquiry

“I am not satisfied because I am paying almost the same amount of money even when I am not there.” – Both water and hydro-related inquiry

“Our bill is too high. It's a lot higher than it used to be and I'm not sure why.” – Both water and hydro-related inquiry

“The company does not put payment equally between electricity and water. It causes confusion and imbalanced bills.” – Both water and hydro-related inquiry

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Feedback among those whose call reason is billing-related

Thank you

Let’s do something great

Appendix

Study Overview

Objectives

- The main objective of the study is to measure customer satisfaction with their contact experience with Entegrus.
- A secondary study objective is to document First Contact Resolution (FCR) for the OEB and scorecard reporting.

Survey Statistics

- A total of 514 surveys were completed in 2024.
- Where applicable, scores have been statistically tested with prior waves at the 95% confidence level.

Methodology

- A telephone methodology was used for this study.
- The survey was in field from February 12 - October 25, 2024.
- Data collection has been conducted in Canada since 2021.
- FCR includes only hydro-related calls only. Calls related solely to water are excluded following a verification process that involves call listening by Entegrus.

Derived Effort Model for Entegrus

Issue Resolution, Holds and Prior Contacts determine the level of effort experienced by callers

Entegrus Effort Model

Experience	Points: Yes	Points: No	Weight
Resolved	0	1	x3
Hold	1	0	x2
Prior Contact	1	0	x1

Customer Effort Level

Total Points	
0	Low/No Effort
1-4	Med Effort
5-6	High Effort

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Focus on positive phrasing when a Transfer is necessary

Focus on positive language to emphasize what you **can** do

From negative language...		...to positive language
"**Unfortunately**, I **can't help** you with that."	→	"___ **can take care of that** for you. **Let me help** by connecting you."
"I **have to transfer you** to the Billing department."	→	"I'd **be happy to** connect you with ___ so **they can help** you out!"
"You'll **need to** talk to IT for that."	→	"_____ is the **best able to to help** with that."
"I'm **not allowed to help** you with this, so..."	→	"___ **should be able to assist** with issues like this."
"**I'm sorry**, there's **nothing I can do**, so ___ will **have to** help you"	→	"**Let me help** by connecting you with ___ **so you can get this issue resolved ASAP**!"

When possible, avoid positioning the transfer as something you need to do because you can't help the caller yourself or aren't allowed to.

Instead, frame the transfer itself as helping the caller by connecting them with the person who is best equipped to get them resolution.

Taking Action: Delivering Bad News

Be transparent & direct without over-explaining:

- Actively listen & use probing questions to clarify key details
- Don't avoid giving specifics that might be disappointing
- Offer enough detail to understand the situation, but not so much that you sound like you're making excuses
- Make it clear why this is relevant to them with clear, simple, specific details, and call out any ways it helps/protects them
- Express empathy & recognize the difficulty they face: being honest doesn't mean being blunt or uncaring
- Recap, confirm next steps, & check for any remaining questions

Try to uncover their immediate concern:

- Use probing open-ended questions to better understand what's at the heart of their worry or frustration
- Understanding their main concerns allows you to offer more relevant options and helps convey your desire to help them
- **Example:** For a Price Increase call…
  - Is the price beyond their budget or ability to pay?
  - Are they confused about why their price increased?
  - Do they feel the increase is unfair or excessive?
  - Do they think they could get a better rate elsewhere?
  - Do they think the produce/service doesn't justify the new cost?
  - Do they believe the increase reflects an error?

Use positive language:

- Acknowledge the situation, then focus on what you **can** do instead of what you **can't**
- **Example:** "While we're unable to revert to the old price, **I'd be happy to review the options available** to see if we can work together to see if we can **find another solution that meets your needs** at a more acceptable price point."

Words & phrases to avoid:

- Too many uncertain statements/sounds (uh, um, ah)
- Apologizing for how they feel ("I'm sorry **you're** disappointed")
- Implying it's just out of your hands ("Unfortunately," "I'm afraid," "There's nothing I can do," "My hands are tied")
- Repeating phrases that circle the main point
- Anything that could come across as accusatory or blaming them
- Tip: Practice alternative phrasing, e.g. "Let's discuss alternatives"

Brainstorm potential solutions:

- Actively listen. Ask good, probing questions to control the conversation and better understand what they need.
- Proactively offer any relevant alternatives, then help them assess those options and provide guidance.
- Even if you don't find a solution that they're happy with, you'll have shown flexibility and a desire to help.
- If you **do** find a solution, offer clear next steps & realistic timelines, and avoid giving "homework" if possible.

ATTACHMENT 1-G

Innovative Research Group

Customer Consultation Reports

Needs and Preferences Survey

Phase I Customer Engagement

August 2024

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Table of Contents

Phase I Online Survey Report Overview

Introduction	3
Sample Validation	5
Summary Results	8

Residential Survey Results

Methodology	11
Demographics	12
Detailed Results	15

Small Business Workbook Results

Methodology	63
Firmographics	64
Detailed Results	66

Commercial & Industrial Workbook Results

Methodology	97
Firmographics	98
Detailed Results	100

INNOVATIVE RESEARCH GROUP

Introduction

Phase I Customer Engagement Survey

Entegrus 2026 Cost of Service Rate Application Customer Engagement (Phase I)

Innovative Research Group Inc. (INNOVATIVE) was engaged by Entegrus Powerlines Inc. to assist in meeting its customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors and Chapter 5 Filing Requirements. The information contained within this report is the result of a series of online surveys conducted as part of Phase I of this customer engagement.

Setting the Context

Entegrus is in the early stages of developing its 2026 Cost of Service Rate Application. In order to ensure that Entegrus' plans are responsive to the needs and preferences of customers, a two-phased customer engagement program has been developed. The results within this report reflect the first phase of this engagement.

In Phase I, Entegrus and INNOVATIVE set out to develop a current understanding of customer needs and preferences, as well as gain some preliminary insights on some more specific investments that could be further explored in Phase II.

Phase I of this engagement focused on understanding the range of views that exist within the customer base and how different types of customers perceive certain issues. A key principle of this phase uses random-sampling research methods to ensure a representative sample of customers were engaged, ensuring the generalizability of the findings.

For residential and small business (GS<50kW), responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. Due to the size of the rate classes, Commercial and Large Use were not weighted and are presented in frequencies rather than percentages.

Introduction
Segmenting Customers

Customer Segmentation

In addition to segmenting customers based on where they reside or operate in Entegrus' service territory, it is important to be able to identify factors that may influence customer preferences and distinguish between what is within, and what is outside of Entegrus' influence or control.

Segmentation has been used throughout the residential and small business sections of this report to look beyond the topline numbers to analyze the results for key segments:

1. **Region:** Using customer data provided by Entegrus, we split customers into four regions for analysis; Chatham, St. Thomas, Strathroy, and the "rest" (i.e., outside of the other three regions).

2. **Bill Impact on Finances**: Segmentation that INNOVATIVE refers to as "Bill Impact on Finances" is provided. This segment is determined based on the extent to which customers agree with the following statement:

   a) Residential: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

   b) Small Business*: The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.*

3. **Vulnerable Consumers**: For residential customers, using a combination of household size and combined household income, the report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's *Ontario Electricity Support Program (OESP)* criteria.

4. **Consumption Quartiles**: For residential and small business customers, results are also shown by consumption quartiles, or otherwise, how much electricity the customer consumes in an average month (in KWh). This is used to ensure that no one customer consumption profile is over or underrepresented in the survey results.

Understanding Segmentation

Segmentation is an effective way of looking past the topline numbers and dig deeper into the needs and preferences of the customer segments above. For instance, while it is valuable to know that, overall, 74% of residential customers are satisfied with Entegrus, it is also important to understand whether satisfaction differs based on region or based on perceptions that may be outside of the utility's influence or control. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel about various issues.

Sample Validation

Email Coverage

Sample Validation

To ensure that customers reached by email are representative of the broader population of Entegrus customers, we use Entegrus' complete customer lists to compare known sample variables between those with an email address and the full population of customers.

This allows us to identify any systematic differences between those with an email on file and the full population of customers on known variables that may impact outcomes. All samples that are weighted include quotas by region and (collapsed) consumption quartile to ensure representativeness.

Overall Customer Email Coverage

The table below summarizes the email coverage of each rate class.

Rate Class	Total Records (Meters)	Unique customers*	Customers with an email	Email coverage (out of customers)
Residential	55,179 meters	50,902	20,275	**39.8%**
Small Business (GS<50)	5,745 meters	3,377	1,546	**45.8%**
C&I/Large Use (GS>50)	506 meters	330	173	**52.4%**

*Unique *customers* from the complete list of Entegrus' records (individual meters) are identified by cross-referencing available contact information to identify customers with multiple meters. Customers are assigned to their highest-order rate class in the following order (Large Use, Commercial & Industrial, Small Business (GS<50kW), Residential). For customers with multiple records within the same rate class, the record with the highest average monthly consumption is used for the purpose of assigning sample variables.

Sample Validation

Email Sample vs. Total Customer Accounts

Sample Validation

The information on this page and the one following compares the sample of each rate class with email addresses to the total customer accounts of that rate class across two known variables – distributions of (1) region and (2) average monthly consumption.

(1) Regional Distribution by Rate Class

Communities are grouped into four unique regions within Entegrus' service territory.

Across rate classes, St.Thomas is underrepresented in the email sample due to lower-than-average email coverage. This difference is accounted for in the survey results by setting quotas based on region to ensure the survey results are representative of the Entegrus customer base.

Legend: Difference*
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

Rate Class	Region	Share of full population	Share of email sample	Difference
Residential	Chatham	31%	40%	**+9%**
	St. Thomas	30%	23%	**-8%**
	Strathroy	10%	7%	**-3%**
	Rest	28%	30%	**+2%**
Small Business (GS<50)	Chatham	28%	34%	**+5%**
	St. Thomas	31%	26%	**-5%**
	Strathroy	10%	8%	**-1%**
	Rest	32%	32%	**+1%**
C&I/Large Use (GS>50)	Chatham	34%	37%	**+3%**
	St. Thomas	24%	18%	**-5%**
	Strathroy	12%	5%	**-6%**
	Rest	31%	39%	**+8%**

INNOVATIVE RESEARCH GROUP

Sample Validation

Email Sample vs. Total Customer Accounts Cont'd

(2) Distribution of Consumption Quartile by Rate Class

Across rate classes, the distributions of consumption quartile between the full population and email sample are similar (+- 4%). For C&I/Large Use customers, average monthly demand measured (kW) is higher in the email sample than in the full population.

This difference is accounted for in the survey results by setting quotas based on consumption quartile to ensure the survey results are representative of the Entegrus customer base.

Legend: Difference*
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

Rate Class	Consumption Quartile	Share of full population	Share of email sample	Difference
Residential	First	25%	23%	**-2%**
	Second	25%	25%	**0%**
	Third	25%	26%	**+1%**
	Fourth	25%	26%	**+1%**
	Average Monthly Consumption (kWh)	589.76	598.63	**+2%**
Small Business (GS<50)	First	25%	24%	**-1%**
	Second	25%	24%	**-1%**
	Third	25%	25%	**0%**
	Fourth	25%	27%	**+2%**
	Average Monthly Consumption (kWh)	2,347.17	2,427.65	**+3%**
C&I/Large Use (GS>50)	First	25%	25%	**0%**
	Second	25%	24%	**-1%**
	Third	25%	27%	**+2%**
	Fourth	25%	24%	**-1%**
	Average Monthly Demand (kW)	325.80	365.16	**+12%**

Summary Results
Customer Priorities

(%) indicates total percentages that place specific priority in their top 3. Only 5 most commonly selected general priorities shown.	Rate Class Unweighted n (Weighted in brackets) Residential n=1,733 (1,200)	Small Business n=89 (80)	C&I n=27
General Priorities			
Delivering electricity as reasonable distribution rates	73%	70%	21/27
Ensuring reliable electrical service	57%	63%	17/27
Replacing aging infrastructure	39%	42%	8/27
Ensuring the safety of electricity infrastructure	33%	35%	9/27
Investing in technology to withstand adverse weather	22%	27%	11/27
Reliability Priorities			
Reducing the length of time to restore power during extreme weather events	60%	52%	18/27
Reducing the overall number of outages	58%	73%	15/27
Reducing the overall length of outages	56%	72%	19/27
Reducing the number of outages during extreme weather events	51%	46%	14/27
Improving the quality of power, as judged by momentary interruptions	44%	42%	12/27
Technology Priorities			
New technology that would reduce the number and length of outages	73%	87%	23/27
New technology that can help customers better manage their electricity usage	72%	65%	19/27
New technology that enables customers to access new electricity services	53%	60%	13/27
New technology to reduce the environmental impact of Entegrus' operations	46%	36%	12/27
New technologies that make it easier to interact with Entegrus	24%	27%	3/27

Note: Priority labels have been shortened for brevity.

Summary Results

Investment Trade-Offs

(%) indicates total percentages that selected response. 'Don't know' not shown.	Rate Class Unweighted n (Weighted in brackets) Residential n=1,733 (1,200)	Small Business n=89 (80)	C&I n=27
System Renewal Projects that replace and restore aging infrastructure, like overheard poles & underground cables.			
Invest what it takes	73%	78%	18/27
Defer its investments	16%	14%	6/27
System Service Infrastructure investments to support increased demand for electricity.			
Proactively make investments	63%	61%	16/27
Delay investments	23%	19%	6/27
Grid Modernization New technology that can provide benefits but will cost customers more.			
Invest in new technologies	65%	66%	17/27
Avoid investments in new technologies	20%	18%	7/27
System Monitoring New technology to allow Entegrus to become more targeted in tree maintenance.			
Invest in this technology	67%	74%	18/27
Do not invest in this technology	23%	18%	8/27
Demand Response Likelihood to enrol in an opt-in demand response program (before potential incentive shown).			
Likely (very + somewhat)	39%	41%	7/27
Not likely (not very + not likely at all + never)	31%	28%	17/27
Would need more information	24%	23%	3/27

Top 3 potential customer service offerings of interest by Rate Class

Residential n=1,733 (1,200)	Small Business n=89 (80)	C&I n=27
Unplanned outage alerts via text (35%)	A mobile application (35%)	Online tool to report outages (10/27)
A mobile application (34%)	Unplanned outage alerts via text (34%)	Unplanned outage alerts via text (8/27)
High usage notifications via text (22%)	Online tool to report outages (25%)	A mobile application (7/27)

Note: Response labels have been shortened for brevity.

Residential Customers

Online Survey Results

Online Survey
Survey Design & Methodology

Field Dates

The **Residential Online Survey** was sent to a random selection of Entegrus residential customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **June 17th and July 9th, 2024**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the residential survey was sent to **13,089** customers from *engage@entegrus.com*. Reminder emails were sent on June 25th, July 2nd, and July 8th, 2024 to those who had not yet completed the survey.

Residential Online Survey Completes

A total of **1,733** (unweighted) Entegrus residential customers completed the online survey.

Sample Weighting

The residential online survey sample was weighted down to n=1,200 proportionately by consumption quartiles and region in order to be representative of the broader Entegrus customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Chatham	190 (110)	199 (97)	178 (89)	137 (79)	704 (374)
St. Thomas	81 (80)	111 (95)	105 (97)	88 (96)	385 (368)
Strathroy	27 (21)	17 (27)	23 (33)	23 (36)	90 (117)
Rest	124 (91)	145 (83)	149 (83)	136 (84)	554 (341)
Total	422 (302)	472 (302)	455 (302)	384 (295)	1,733 (1,200)

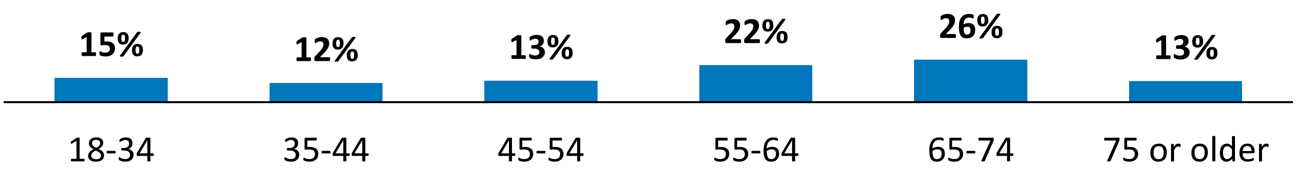
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Survey

Demographic breakdown

Residential

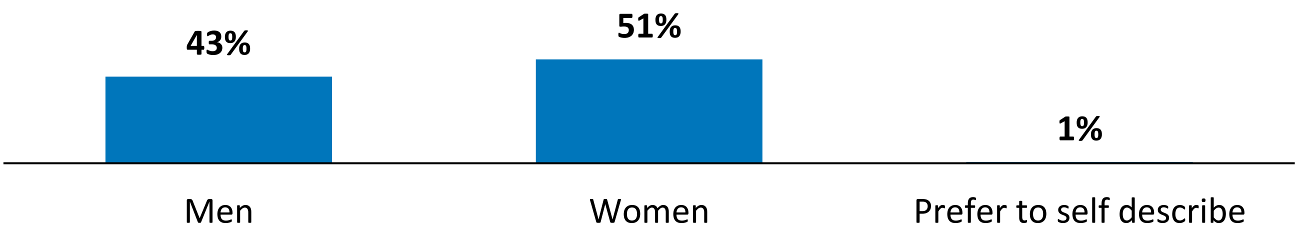
Q Age



“Prefer not to say” (<1%) not shown.

n=1,200

Q Gender



“Prefer not to say” (6%) not shown.

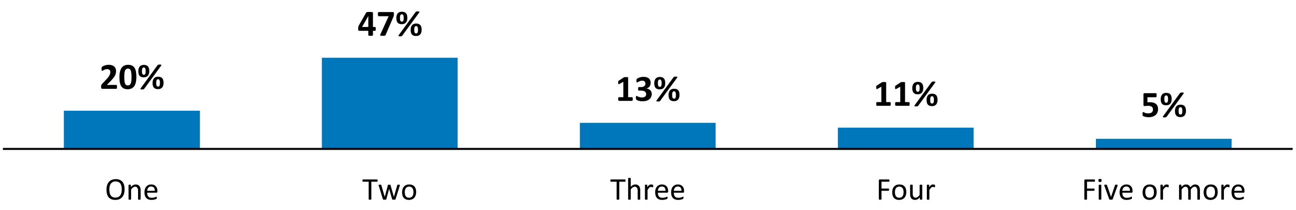
n=1,200

Online Survey

Demographic breakdown

Residential

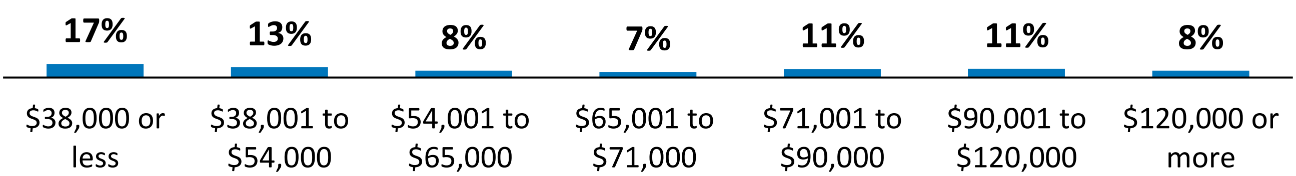
Q Household Size



“Prefer not to say” (4%) not shown.

n=1,200

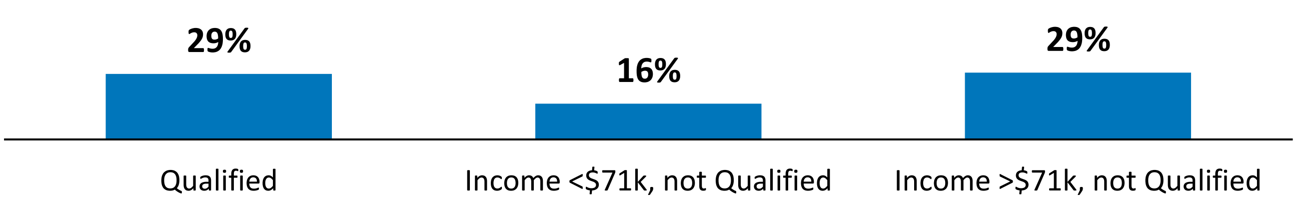
Q After Tax Household Income



“Prefer not to say” (26%) not shown.

n=1,200

Q **LEAP/OESP Qualification** (based on household size and income)



“Prefer not to say” (26%) not shown.

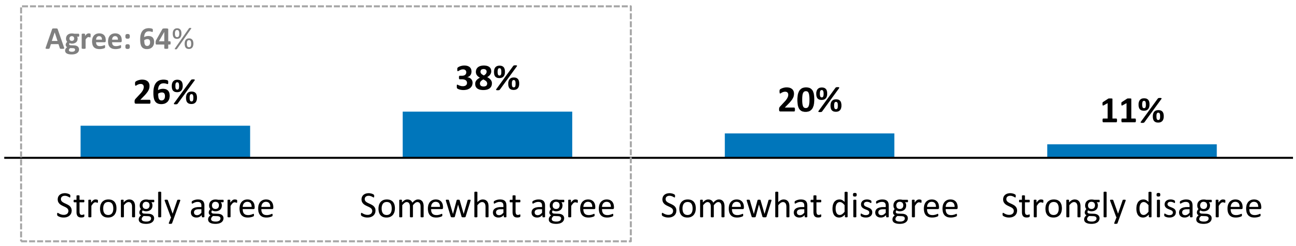
n=1,200

Online Survey
Environmental Controls

Residential

To what extent do you agree or disagree with the following statements?

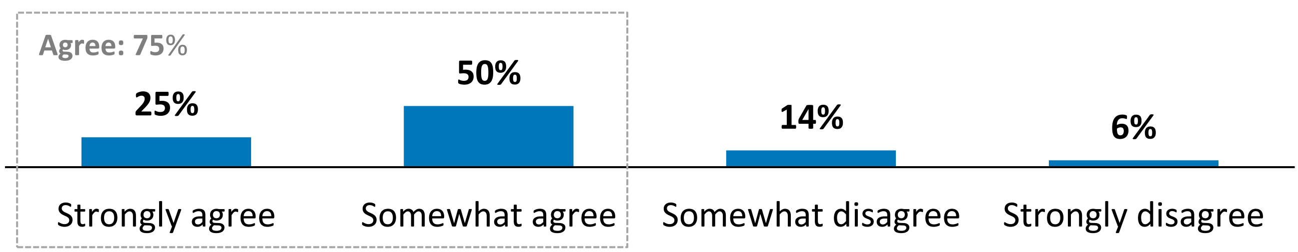
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=1,200

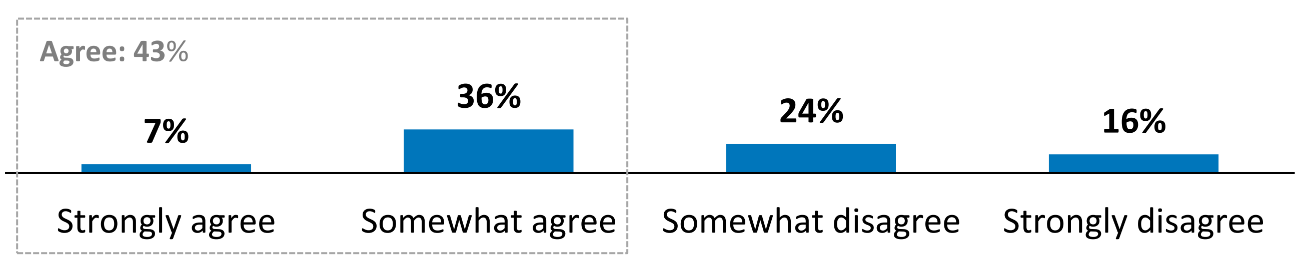
Q Customers are well-served by the electricity system in Ontario.



"Don't know/no opinion" (6%) not shown.

n=1,200

Q Customers are protected with respect to the price we pay for electricity.



"Don't know/no opinion" (17%) not shown.

n=1,200

Online Survey

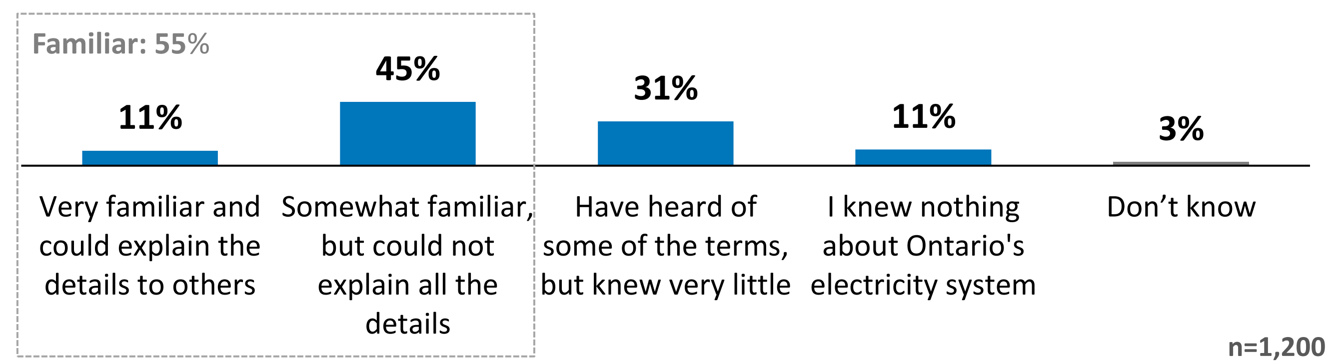
Familiarity with Ontario's Electricity System

Residential

As you may know, Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province
- **Local distribution networks** take the electricity from provincial transmission lines and bring it to your home through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with the various parts of the electricity system and how they work together?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very familiar	12%	11%	7%	10%	10%	12%
Somewhat familiar	46%	41%	49%	45%	42%	49%
Knew very little	28%	33%	33%	32%	33%	28%
Knew nothing	12%	13%	8%	10%	13%	8%
Don't know	2%	3%	3%	3%	2%	3%
Familiar (Very + Somewhat)	**58%**	**52%**	**56%**	**55%**	**52%**	**61%**

Online Survey

Familiarity with Ontario's Electricity System

Residential

Q Before this survey, how familiar were you with the various parts of the electricity system and how they work together?

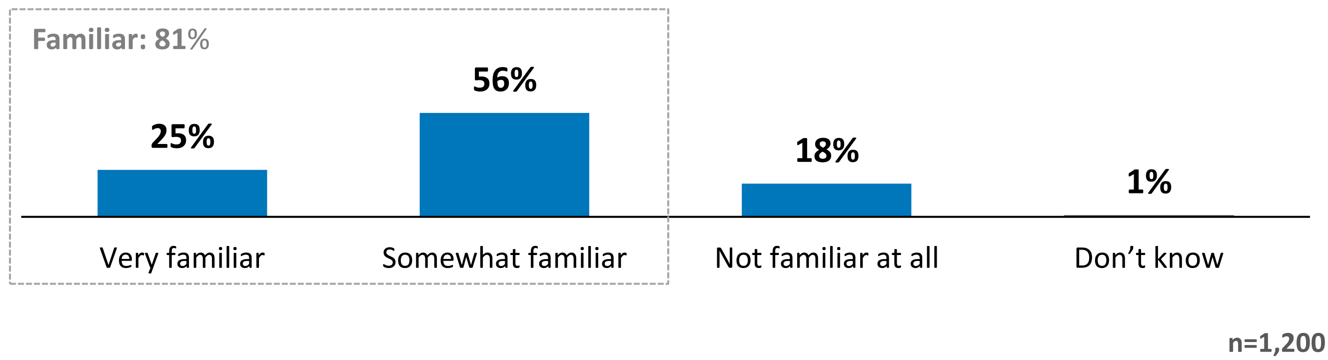
		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very familiar	11%	9%	10%	12%	12%	9%	10%	13%
Somewhat familiar	45%	43%	42%	48%	45%	37%	51%	49%
Knew very little	31%	31%	35%	27%	30%	34%	30%	29%
Knew nothing	11%	13%	10%	12%	11%	17%	9%	8%
Don't know	3%	5%	3%	1%	2%	3%	1%	1%
Familiar (Very + Somewhat)	**55%**	**52%**	**52%**	**60%**	**57%**	**46%**	**60%**	**62%**

Online Survey
Familiarity with Entegrus

Residential

Entegrus manages all aspects of the electricity distribution business throughout 17 communities in Southwestern Ontario. This is the network that takes the electricity from high-voltage transmission towers and brings it to your home or business through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with **Entegrus**, which operates the electricity distribution system in your community?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very familiar	27%	22%	22%	28%	25%	26%
Somewhat familiar	57%	55%	59%	55%	55%	57%
Not familiar at all	15%	22%	18%	16%	19%	16%
Don't know	<1%	1%	1%	1%	1%	1%
Familiar (Very + Somewhat)	**85%**	**76%**	**81%**	**83%**	**80%**	**83%**

Online Survey

Familiarity with Entegrus

Residential

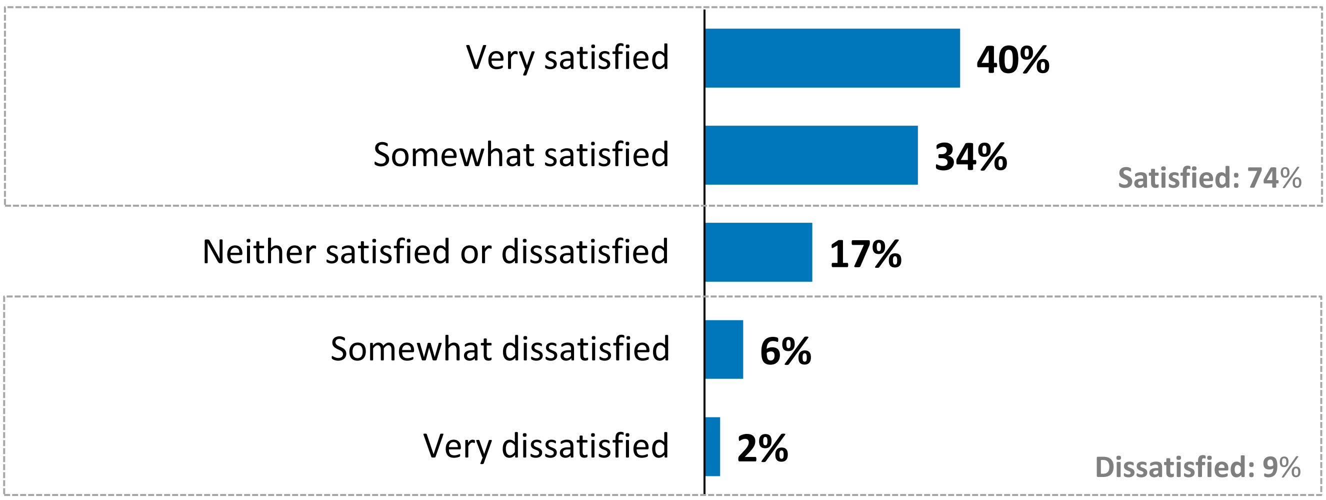
Q Before this survey, how familiar were you with **Entegrus**, which operates the electricity distribution system in your community?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very familiar	25%	21%	23%	27%	31%	25%	23%	30%
Somewhat familiar	56%	55%	58%	56%	55%	54%	59%	56%
Not familiar at all	18%	23%	19%	17%	13%	20%	18%	14%
Don't know	1%	2%	1%	<1%	1%	2%	<1%	<1%
Familiar (Very + Somewhat)	**81%**	**75%**	**81%**	**83%**	**87%**	**79%**	**82%**	**85%**

Online Survey
Overall Satisfaction with Entegrus

Residential

Q Thinking specifically about the services provided to you and your community by **Entegrus**, overall, how satisfied or dissatisfied are you with the services that you receive?



"Don't know" (1%) not shown.

n=1,200

	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very satisfied	44%	35%	46%	39%	35%	50%
Somewhat satisfied	33%	34%	33%	33%	35%	32%
Neither satisfied nor dissatisfied	15%	21%	12%	17%	18%	14%
Somewhat dissatisfied	5%	6%	5%	8%	8%	2%
Very dissatisfied	2%	3%	3%	2%	3%	1%
Don't know	1%	1%	--	1%	<1%	1%
Satisfied (Very + Somewhat)	**78%**	**70%**	**79%**	**72%**	**70%**	**82%**
Dissatisfied (Very + Somewhat)	**7%**	**9%**	**8%**	**10%**	**12%**	**3%**

Online Survey

Overall Satisfaction with Entegrus

Residential

Q Thinking specifically about the services provided to you and your community by **Entegrus**, overall, how satisfied or dissatisfied are you with the services that you receive?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very satisfied	40%	44%	44%	38%	35%	42%	44%	42%
Somewhat satisfied	34%	31%	31%	37%	35%	30%	31%	36%
Neither satisfied nor dissatisfied	17%	17%	17%	16%	18%	18%	18%	12%
Somewhat dissatisfied	6%	5%	5%	6%	9%	7%	5%	7%
Very dissatisfied	2%	2%	2%	2%	3%	3%	2%	3%
Don't know	1%	1%	1%	1%	<1%	<1%	--	<1%
Satisfied (Very + Somewhat)	**74%**	**75%**	**75%**	**75%**	**70%**	**72%**	**75%**	**78%**
Dissatisfied (Very + Somewhat)	**9%**	**7%**	**7%**	**8%**	**12%**	**10%**	**7%**	**9%**

Online Survey

How Entegrus can improve its services

Residential

Q Is there anything in particular you would like **Entegrus** to do to improve its services to you?

Response	%
Lower rates/bills/too expensive	14.3%
Improve reliability of service/reduce outages/disruptions	6.0%
Satisfied with services/no issues/complaints	2.8%
Improve/update infrastructure (e.g. bury lines)	2.5%
Reduce delivery fee/service charges	2.4%
Billing improvements - timing/payments/bill format	2.1%
Improve communication during outages	2.0%
Improve customer service	1.2%
More transparency around costs/bills	1.1%
Consistent/better meter readings	1.0%
Line management (e.g. tree trimming, branch clearing, vegetation)	0.9%
Offer programs for seniors/low-income/discounts/subsidies	0.8%
Improve overall communications	0.8%
Educating customers	0.6%
Improve response time for outages	0.5%
Keep pricing affordable/reasonable	0.5%
Offer/improve green energy options	0.5%
Provide incentives/rebates	0.2%
Other	0.7%
None/Don’t know	59.1%

Note: Only responses >0.1% shown

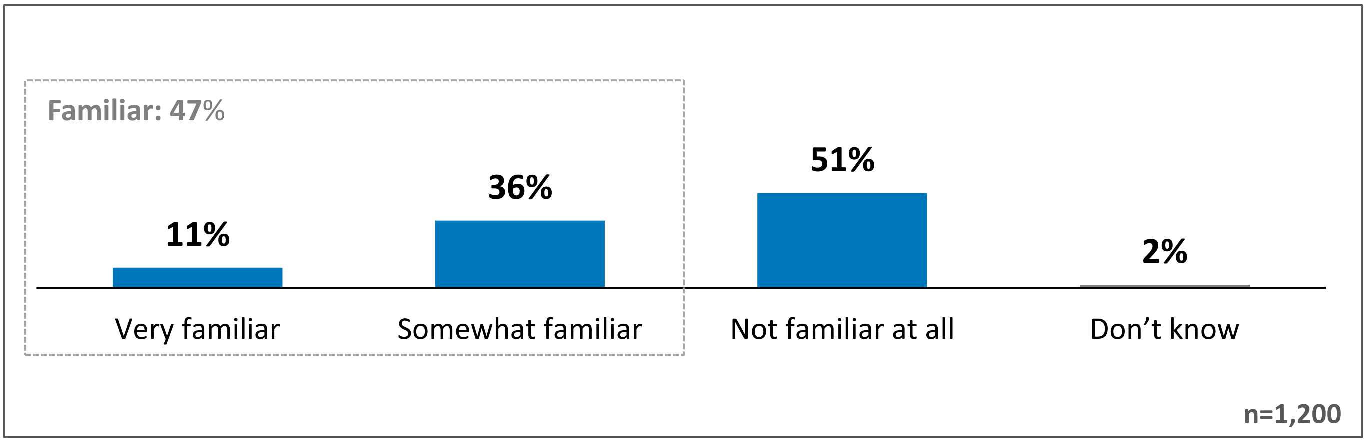
Online Survey
Bill Remittance Familiarity

While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – **Entegrus** retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.

Distribution makes up about **22%** of the typical residential customer's bill.

The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Entegrus**?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very familiar	12%	9%	10%	12%	11%	11%
Somewhat familiar	39%	34%	41%	34%	38%	34%
Not familiar at all	49%	54%	44%	53%	50%	54%
Don't know	<1%	3%	4%	1%	2%	2%
Familiar (Very + Somewhat)	**51%**	**43%**	**52%**	**46%**	**48%**	**45%**

Online Survey

Bill Remittance Familiarity

Residential

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Entegrus**?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very familiar	11%	12%	10%	11%	10%	11%	12%	11%
Somewhat familiar	36%	30%	39%	37%	40%	34%	36%	39%
Not familiar at all	51%	56%	50%	51%	48%	54%	51%	48%
Don't know	2%	2%	2%	2%	2%	2%	<1%	1%
Familiar (Very + Somewhat)	**47%**	**42%**	**48%**	**48%**	**50%**	**44%**	**48%**	**50%**

INNOVATIVE RESEARCH GROUP

Residential Customers

Priorities & Preferences

Online Survey

Importance of Customer Priorities

Residential

Now, let's talk about our second topic – outcomes.

Everyday **Entegrus** interacts with hundreds of its customers through multiple channels and touchpoints, including surveys, the call centre and social media.

Through these ongoing interactions with customers, a number of company goals have been identified as priorities for **Entegrus**.

Shortened General Outcomes Priorities Response Labels	Full General Outcomes Priorities Response Labels
Delivering electricity at reasonable distribution rates	Delivering electricity at reasonable distribution rate
Ensuring reliable electrical service	Ensuring reliable electrical service
Investing in technology to withstand adverse weather	Investing in new technology that could lead to benefits such as better withstanding the impacts of adverse weather
Replacing aging infrastructure	Replacing aging infrastructure that is beyond its useful life
Quality customer service and communications	Providing quality customer service and enhanced communications
Helping customers with conservation and usage	Helping customers with conservation and changing their electricity usage
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure
Expanding grid to reduce impact on climate change	Expanding the electricity grid so that customers can reduce their impact on climate change by using electricity to replace fossil fuels (e.g., replacing gas-powered vehicles with electric vehicles or natural gas heating with heat pumps)
Enabling customers to access new electricity services	Enabling customers to access new electricity services (e.g., electricity storage, power walls and distributed generation, such as solar panels)

Online Survey

Importance of Customer Priorities

Residential

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Entegrus** priorities to you as a customer?

Delivering electricity at reasonable distribution rates [average = **9.4**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Don't know	Extremely important
	1%	<1%	<1%	<1%	1%	3%	1%	3%	5%	9%	76%	2%	

Ensuring reliable electrical service [average = **9.3**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Don't know	Extremely important
	<1%	<1%	<1%	<1%	<1%	3%	1%	3%	7%	11%	72%	2%	

Ensuring the safety of electricity infrastructure [average = **8.9**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Don't know	Extremely important
	1%	<1%	<1%	1%	1%	6%	2%	4%	10%	12%	60%	2%	

Replacing aging infrastructure [average = **8.6**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Don't know	Extremely important
	1%	<1%	<1%	1%	1%	7%	3%	8%	14%	14%	50%	1%	

Quality customer service and communications [average = **8.5**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Don't know	Extremely important
	1%	<1%	1%	1%	1%	7%	4%	8%	13%	14%	50%	1%	

Note: Priority labels have been shortened for brevity. See slide 25 for full label text.
"Don't know" is not included in the calculation of means.

Online Survey

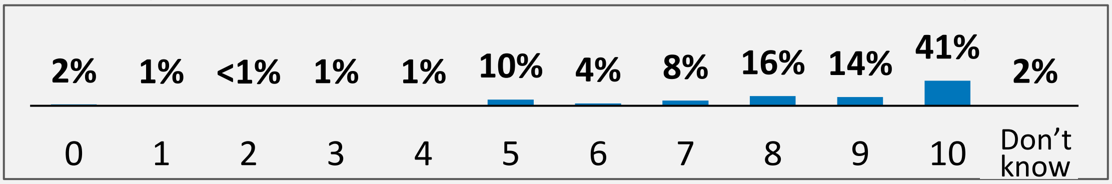
Importance of Customer Priorities (Cont'd)

Residential

Q Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Entegrus** priorities to you as a customer?

Investing in technology to withstand adverse weather [average = **8.1**]

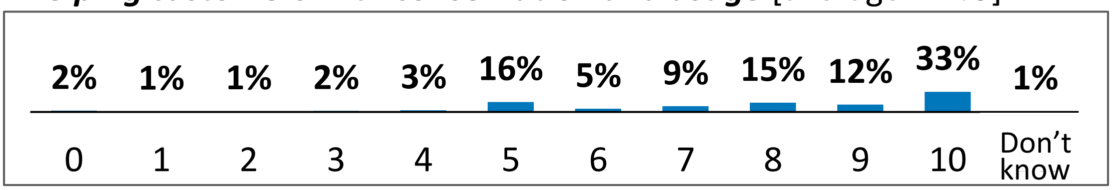
Not at all important



Extremely important

Helping customers with conservation and usage [average = **7.6**]

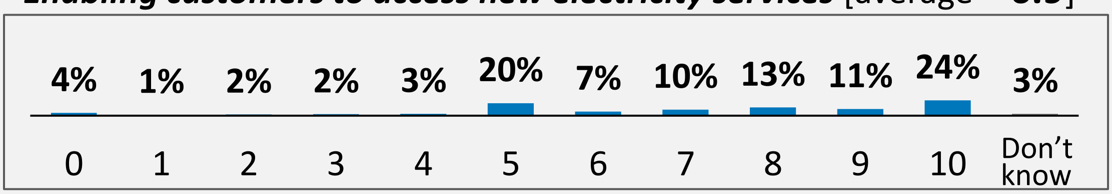
Not at all important



Extremely important

Enabling customers to access new electricity services [average = **6.9**]

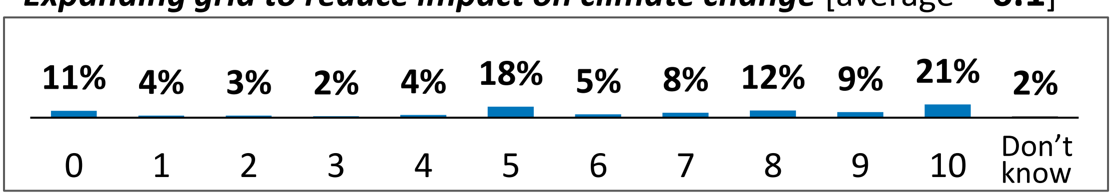
Not at all important



Extremely important

Expanding grid to reduce impact on climate change [average = **6.1**]

Not at all important



Extremely important

Note: Priority labels have been shortened for brevity. See slide 25 for full label text.
"Don't know" is not included in the calculation of means.

Online Survey

Importance of Customer Priorities – Average Scores

Residential

Q

Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Entegrus** priorities to you as a customer?

Average Score	Region					Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Delivering electricity at reasonable distribution rates	9.4	9.4	9.4	9.8	9.3	9.4	9.4
Ensuring reliable electrical service	9.3	9.3	9.4	9.6	9.3	9.2	9.6
Ensuring the safety of electricity infrastructure	8.9	9.0	8.9	9.0	8.8	8.7	9.2
Replacing aging infrastructure	8.6	8.7	8.6	8.7	8.6	8.5	8.9
Quality customer service and communications	8.5	8.6	8.4	8.8	8.5	8.4	8.7
Investing in technology to withstand adverse weather	8.1	8.3	8.0	8.2	8.0	8.0	8.4
Helping customers with conservation and usage	7.6	7.6	7.6	7.5	7.5	7.6	7.5
Enabling customers to access new electricity services	6.9	7.1	7.0	6.8	6.8	7.0	6.9
Expanding grid to reduce impact on climate change	6.1	6.2	6.6	5.9	5.6	5.9	6.6

Note: Priority labels have been shortened for brevity. See slide 25 for full label text.
"Don't know" is not included in the calculation of means. "Don't know" not shown.

Online Survey

Importance of Customer Priorities – Average Scores

Residential

Q Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Entegrus** priorities to you as a customer?

Average Score	Overall	Consumption Quartiles: Low	Medium-Low	Medium-High	High	LEAP/OESP Qualification: Qualified	<$71k Not Qualified	>$71k Not Qualified
Delivering electricity at reasonable distribution rates	9.4	9.2	9.4	9.4	9.5	9.4	9.2	9.5
Ensuring reliable electrical service	9.3	9.3	9.3	9.4	9.4	9.2	9.4	9.5
Ensuring the safety of electricity infrastructure	8.9	8.9	8.9	9.0	8.7	8.9	8.9	9.0
Replacing aging infrastructure	8.6	8.6	8.7	8.7	8.5	8.5	8.6	8.8
Quality customer service and communications	8.5	8.5	8.6	8.5	8.5	8.7	8.5	8.4
Investing in technology to withstand adverse weather	8.1	8.0	8.3	8.3	7.9	7.9	8.2	8.3
Helping customers with conservation and usage	7.6	7.5	7.7	7.5	7.7	7.9	7.5	7.5
Enabling customers to access new electricity services	6.9	6.7	7.0	6.9	7.1	7.0	7.0	7.1
Expanding grid to reduce impact on climate change	6.1	6.1	6.2	6.0	6.3	6.1	6.2	6.3

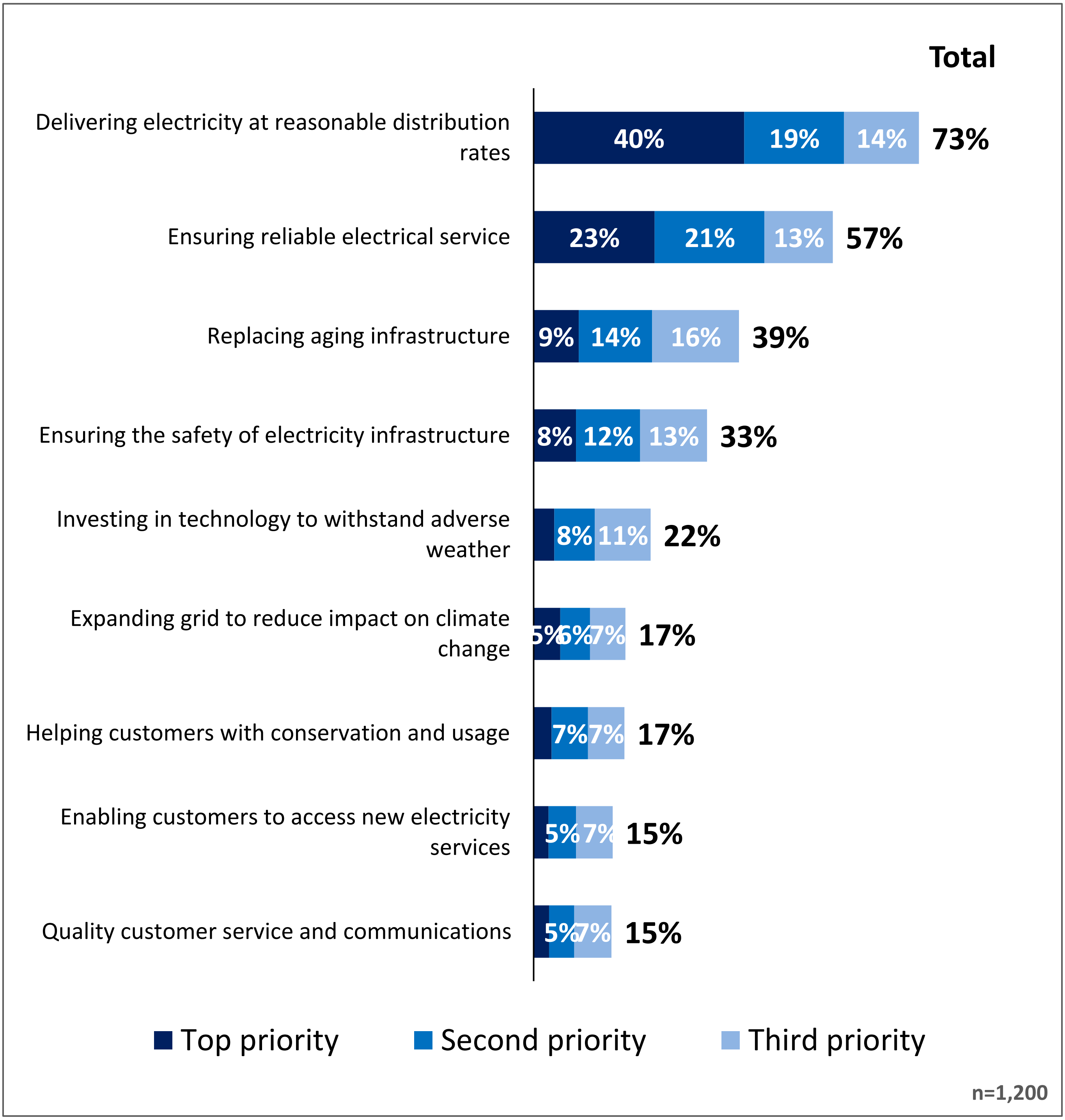
Note: Priority labels have been shortened for brevity. See slide 25 for full label text.
"Don't know" is not included in the calculation of means. "Don't know" not shown.

Online Survey

Ranking Customer Priorities

Residential

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Entegrus** should focus on? And what do you consider the third most important priority?



Note: Priority labels have been shortened for brevity. See slide 25 for full label text. Data labels are removed where 4% or less. "Don't know" is not shown.

Online Survey

Ranking Customer Priorities – Summary

Residential

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Entegrus** should focus on? And what do you consider the third most important priority?

% who select as top 3 priority	Region					Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Delivering electricity at reasonable distribution rates	73%	73%	70%	74%	75%	76%	66%
Ensuring reliable electrical service	57%	58%	49%	64%	61%	54%	61%
Replacing aging infrastructure	39%	39%	38%	34%	42%	37%	43%
Ensuring the safety of electricity infrastructure	33%	33%	34%	31%	32%	31%	36%
Investing in technology to withstand adverse weather	22%	24%	21%	20%	22%	21%	25%
Expanding grid to reduce impact on climate change	17%	17%	21%	20%	13%	16%	19%
Helping customers with conservation and usage	17%	16%	19%	13%	17%	21%	11%
Enabling customers to access new electricity services	15%	15%	15%	20%	13%	16%	13%
Quality customer service and communications	15%	15%	15%	17%	14%	16%	13%

Note: Priority labels have been shortened for brevity. See slide 25 for full label text. "Don't know" is not shown.

Online Survey
Ranking Customer Priorities – Summary

Residential

Q

Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Entegrus** should focus on? And what do you consider the third most important priority?

% who select as top 3 priority	Consumption Quartiles					LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Delivering electricity at reasonable distribution rates	73%	73%	73%	70%	77%	76%	71%	71%
Ensuring reliable electrical service	57%	56%	53%	57%	60%	53%	59%	57%
Replacing aging infrastructure	39%	43%	39%	40%	34%	37%	42%	40%
Ensuring the safety of electricity infrastructure	33%	33%	34%	35%	28%	33%	34%	30%
Investing in technology to withstand adverse weather	22%	23%	23%	21%	21%	20%	21%	26%
Expanding grid to reduce impact on climate change	17%	14%	17%	19%	19%	14%	19%	22%
Helping customers with conservation and usage	17%	15%	18%	16%	20%	21%	17%	16%
Enabling customers to access new electricity services	15%	14%	16%	13%	16%	13%	17%	18%
Quality customer service and communications	15%	13%	15%	16%	15%	16%	16%	11%

Note: Priority labels have been shortened for brevity. See slide 25 for full label text. “Don’t know” is not shown.

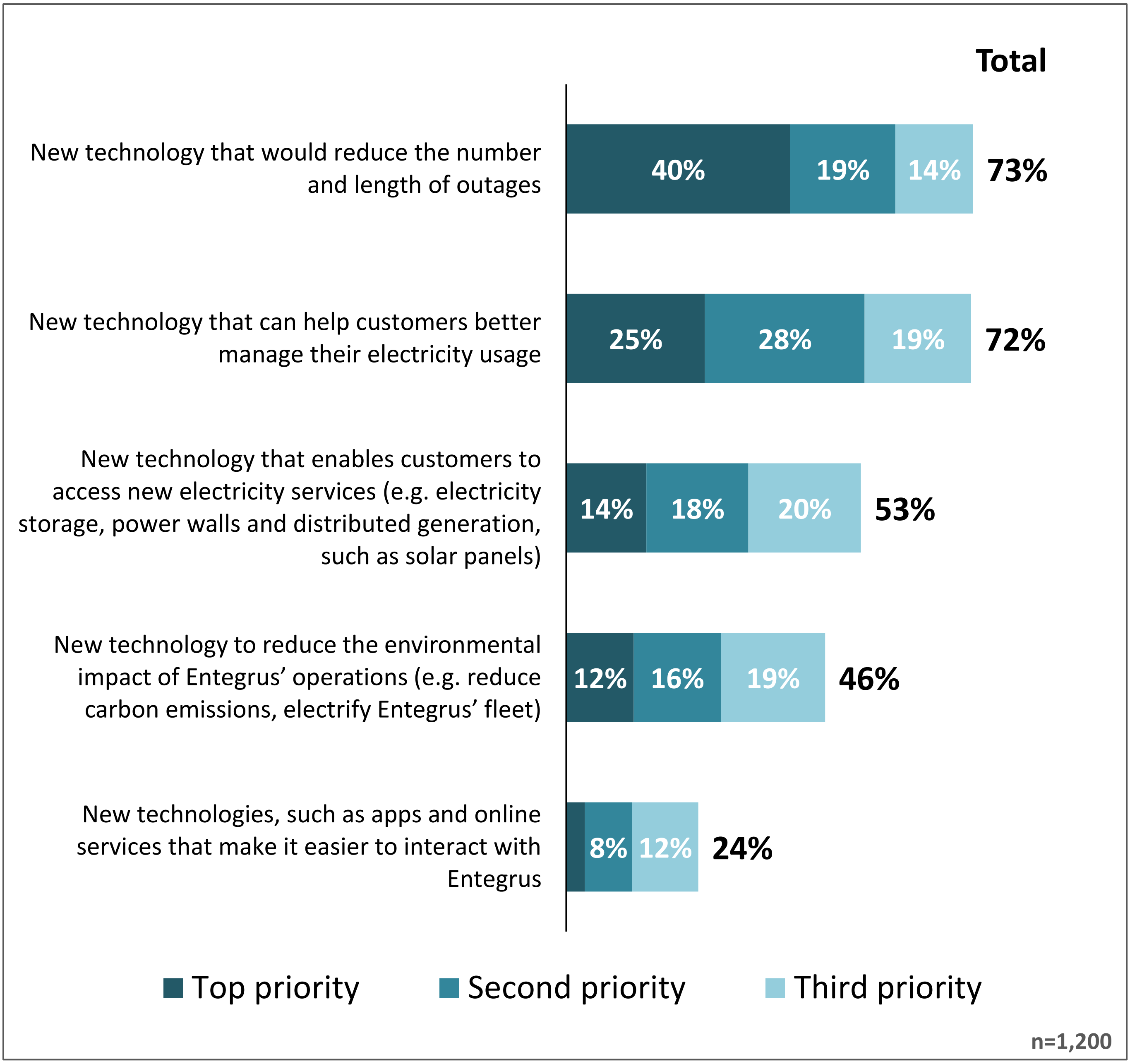
Online Survey

Ranking Investments in New Technology

Residential

Investments in new technology can help **Entegrus** address a range of issues. These include reliability, efficiency, customer service, **Entegrus'** impact on the environment, new service offerings and tools to manage electricity usage.

Q Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Entegrus** should focus on? And what do you consider the third most important priority?



Note: Data labels are removed where 4% or less. "Don't know" not shown.

Online Survey

Ranking Investments in New Technology – Summary

Residential

Q

Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Entegrus** should focus on? And what do you consider the third most important priority?

% who select as top 3 priority	Region					Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
New technology that would reduce the number and length of outages	73%	75%	65%	81%	75%	70%	77%
New technology that can help customers better manage their electricity usage	72%	70%	76%	65%	73%	74%	69%
New technology that enables customers to access new electricity services	53%	54%	55%	45%	51%	52%	53%
New technology to reduce the environmental impact of Entegrus' operations	46%	47%	49%	51%	40%	44%	51%
New technologies, such as apps and online services that make it easier to interact with Entegrus	24%	23%	21%	32%	24%	26%	20%

Note: Priority labels have been shortened for brevity. See slide 33 for full label text. "Don't know" is not shown.

Online Survey

Ranking Investments in New Technology – Summary

Residential

Q

Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Entegrus** should focus on? And what do you consider the third most important priority?

% who select as top 3 priority		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
New technology that would reduce the number and length of outages	73%	73%	69%	76%	72%	68%	73%	77%
New technology that can help customers better manage their electricity usage	72%	70%	76%	71%	72%	74%	75%	70%
New technology that enables customers to access new electricity services	53%	47%	55%	56%	52%	48%	54%	60%
New technology to reduce the environmental impact of Entegrus' operations	46%	47%	45%	47%	45%	46%	50%	47%
New technologies, such as apps and online services that make it easier to interact with Entegrus	24%	22%	23%	24%	25%	23%	22%	26%

Note: Priority labels have been shortened for brevity. See slide 33 for full label text. "Don't know" is not shown.

Online Survey
Additional Priority Areas

Residential

Q Can you think of any other important priorities that **Entegrus** should be focusing on?

Response	%
Reducing costs for customers	8.6%
Address climate change/environment/renewable energy	2.3%
Reliable electrical service	1.3%
No issues/other priorities	1.1%
Programs for seniors/low-income households	1.1%
Better customer service	1.0%
Electric vehicle (EV) infrastructure investment	0.9%
Improve transparency for bills/investments	0.9%
Updating aging infrastructure	0.8%
Improve communication with customers	0.7%
Proactive planning/action for the future	0.6%
Efficient business practices	0.5%
Insight/incentives on managing usage	0.4%
Line maintenance	0.3%
Prioritizing safety	0.2%
More educational resources	0.2%
Bury wires underground	0.2%
Improve website/online services	0.2%
Hire more employees/local workers	0.1%
Maintain cybersecurity	0.1%
Other	2.4%
None/Don't know	76.1%

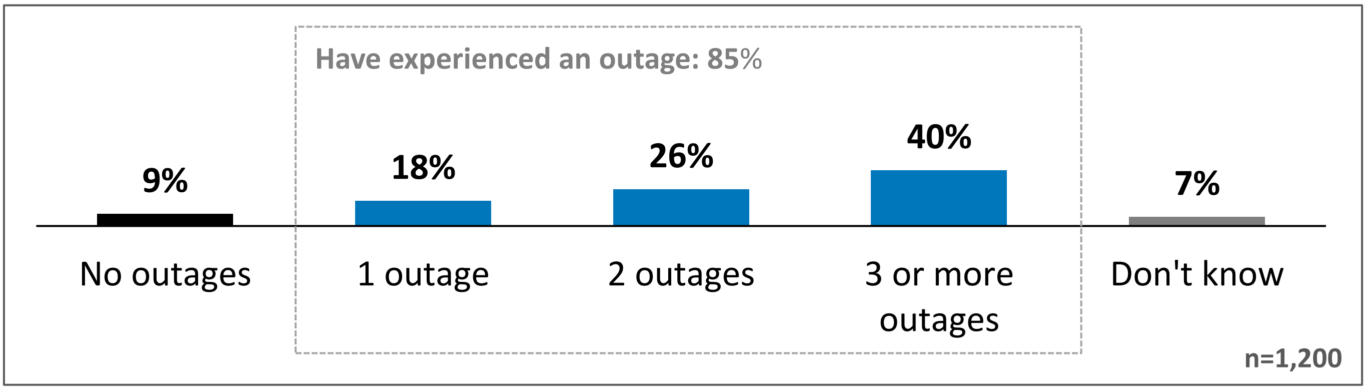
Note: Only responses >0.1% shown

Online Survey
Reliability Experience

Residential

Now, let's talk about the reliability of electricity service you receive.

Q Have you experienced any power outages at **home in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
No outages	5%	12%	12%	8%	10%	7%
1 outage	20%	20%	11%	17%	16%	22%
2 outages	27%	26%	25%	26%	27%	26%
3 or more outages	43%	34%	48%	41%	41%	39%
Don't know	5%	8%	4%	8%	7%	6%
Have experienced at least 1 outage	**90%**	**80%**	**84%**	**84%**	**83%**	**87%**

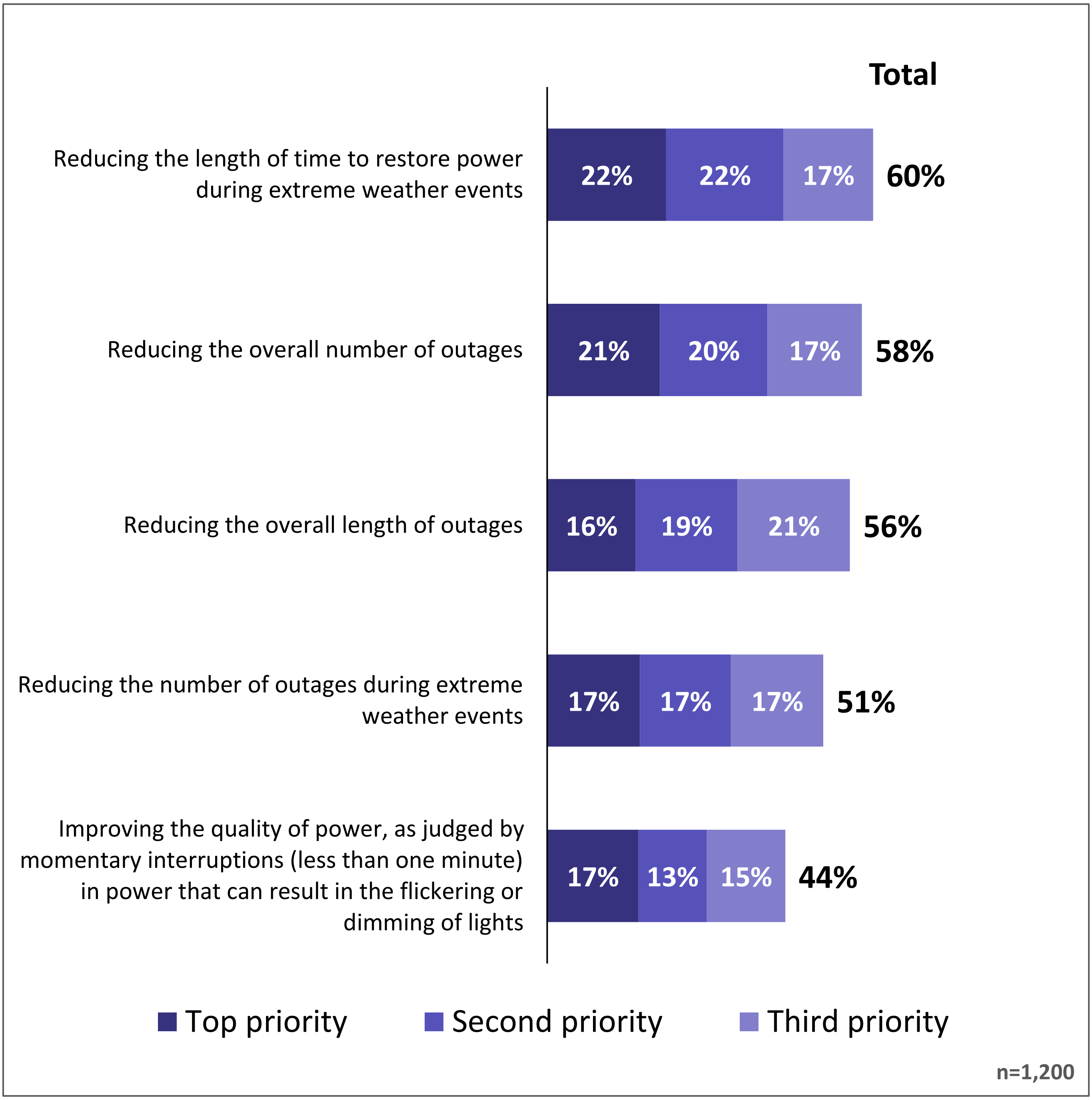
	Consumption Quartiles				LEAP/OESP Qualification		
	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
No outages	9%	7%	10%	8%	9%	9%	8%
1 outage	21%	18%	16%	17%	19%	21%	20%
2 outages	28%	22%	26%	29%	26%	25%	28%
3 or more outages	32%	42%	44%	42%	39%	40%	40%
Don't know	9%	10%	4%	4%	7%	5%	4%
Have experienced at least 1 outage	**82%**	**83%**	**86%**	**88%**	**84%**	**87%**	**87%**

Online Survey

Ranking Reliability Preferences

Residential

Q When it comes to reliability, there are a number of areas that **Entegrus** can focus on. Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Entegrus** should focus on? And what do you consider the third most important priority?



Note: "Don't know" not shown.

Online Survey

Ranking Reliability Preferences – Summary

Residential

Q

When it comes to reliability, there are a number of areas that **Entegrus** can focus on. Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Entegrus** should focus on? And what do you consider the third most important priority?

% who select as top 3 priority		Region				Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Reducing the length of time to restore power during extreme weather events	60%	65%	55%	60%	60%	61%	58%
Reducing the overall number of outages	58%	57%	57%	65%	58%	58%	57%
Reducing the overall length of outages	56%	61%	49%	63%	56%	56%	55%
Reducing the number of outages during extreme weather events	51%	53%	49%	47%	52%	50%	52%
Improving the quality of power, as judged by momentary interruptions	44%	39%	48%	46%	44%	43%	45%

Note: Priority labels have been shortened for brevity. See slide 38 for full label text. "Don't know" is not shown.

Online Survey

Ranking Reliability Preferences – Summary

Residential

Q

When it comes to reliability, there are a number of areas that **Entegrus** can focus on. Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Entegrus** should focus on? And what do you consider the third most important priority?

% who select as top 3 priority		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Reducing the length of time to restore power during extreme weather events	60%	63%	58%	59%	60%	57%	63%	63%
Reducing the overall number of outages	58%	55%	57%	61%	59%	57%	56%	60%
Reducing the overall length of outages	56%	56%	51%	58%	58%	54%	59%	58%
Reducing the number of outages during extreme weather events	51%	51%	52%	53%	49%	53%	59%	53%
Improving the quality of power, as judged by momentary interruptions	44%	41%	44%	44%	46%	43%	41%	47%

Note: Priority labels have been shortened for brevity. **See slide 38 for full label text.** **"Don't know" is not shown.**

Residential Customers

Investment Trade-Offs

Online Survey

Investment Trade-Offs – System Renewal

Residential

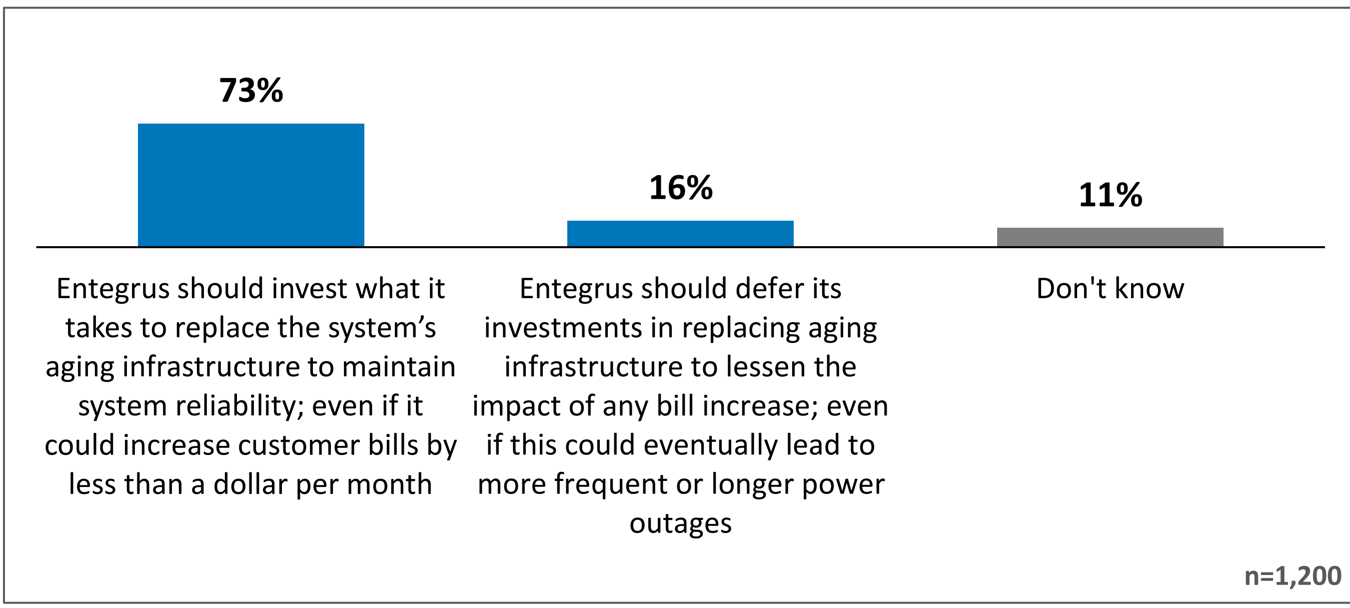
Now let's turn to our third topic – investment trade-offs.

Entegrus is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to know your preferences when it comes to finding the right balance between costs and other outcomes.

There are three investment categories that we would like to discuss.

The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

Q Regarding investments in aging infrastructure, which of the following statements best represents your point of view?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Invest what it takes	74%	72%	70%	74%	66%	86%
Defer investments	14%	16%	16%	17%	21%	5%
Don't know	11%	12%	13%	10%	13%	9%

Online Survey

Investment Trade-Offs – System Renewal

Residential

Q Regarding investments in aging infrastructure, which of the following statements best represents your point of view?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Invest what it takes	73%	73%	74%	74%	72%	65%	77%	80%
Defer investments	16%	15%	15%	14%	18%	21%	12%	14%
Don't know	11%	12%	11%	12%	11%	14%	10%	6%

Online Survey

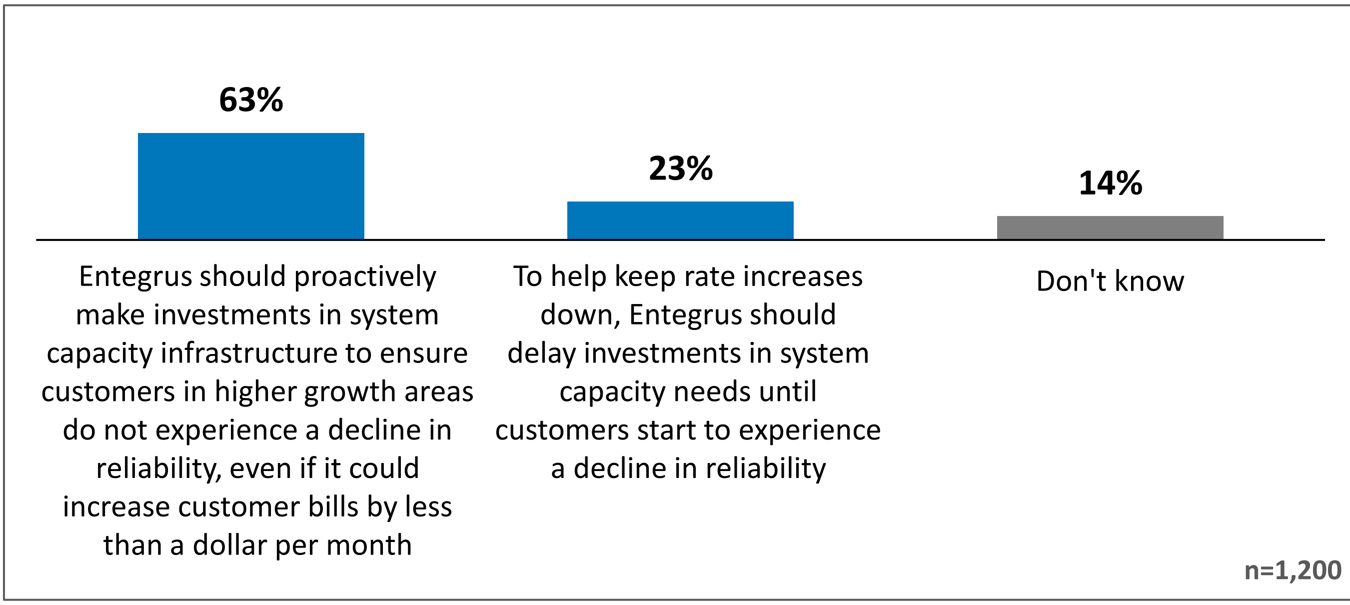
Investment Trade-Offs – System Service

Residential

The second investment category focuses on growth and greater demand for electricity in various parts of **Entegrus'** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

Q With this in mind, which of the following statements best represents your point of view?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Proactive investments in system capacity	66%	64%	61%	61%	56%	77%
Delay capacity investments until reliability declines	21%	21%	21%	27%	30%	10%
Don't know	14%	15%	18%	12%	14%	14%

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Online Survey

Investment Trade-Offs – System Service

Residential

Q With this in mind, which of the following statements best represents your point of view?

	Overall	Consumption Quartiles: Low	Medium-Low	Medium-High	High	LEAP/OESP Qualification: Qualified	<$71k Not Qualified	>$71k Not Qualified
Proactive investments in system capacity	63%	64%	64%	65%	60%	56%	66%	72%
Delay capacity investments until reliability declines	23%	21%	23%	21%	26%	29%	21%	20%
Don't know	14%	15%	13%	14%	14%	15%	12%	8%

Online Survey
Investment Trade-Offs – Grid Modernization

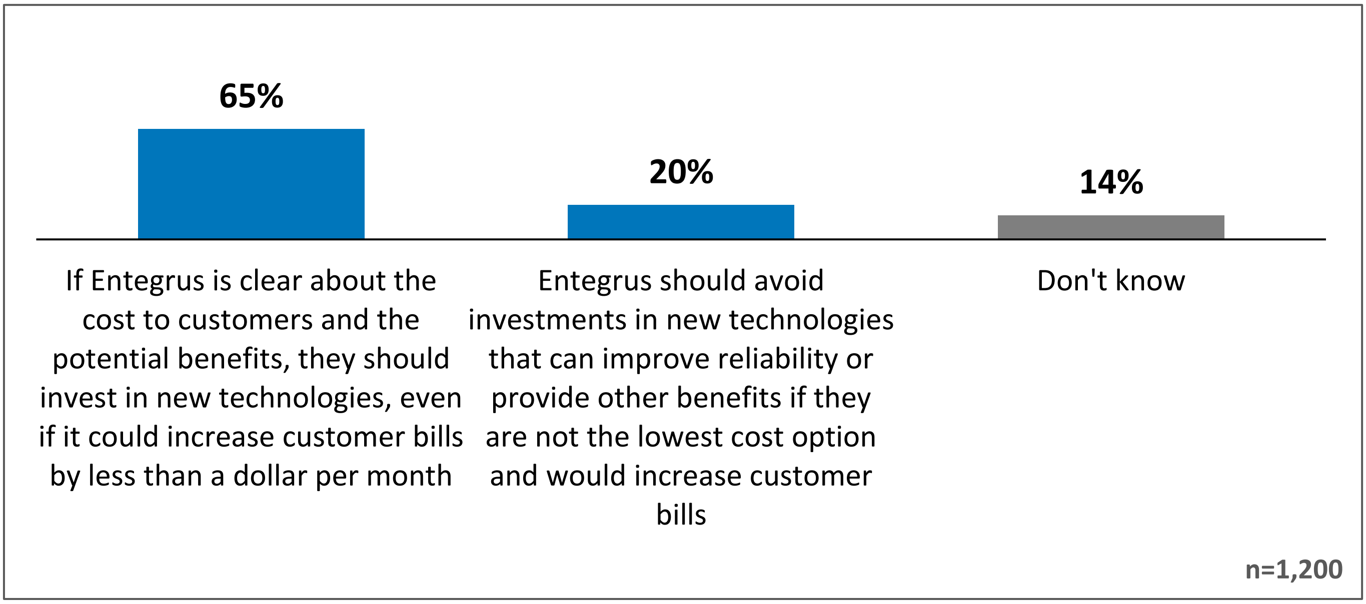
Entegrus can invest in technology that can lead to a wide range of benefits including reliability, efficiency, customer service, and reducing environmental impacts.

Entegrus generally invests in technology when it provides equal or improved service at the least cost.

However, there are times when **Entegrus** identifies *new* technology that can improve reliability or provide other benefits, but it will cost customers more.

For instance, advanced customer meters that can measure when different appliances or equipment are running, allowing **Entegrus** to provide customers with better advice on how to reduce their energy consumption and costs.

Q Regarding these types of investments, which of the following best represents your view?



Online Survey

Investment Trade-Offs – Grid Modernization

Residential

Q Regarding these types of investments, which of the following best represents your view?

		Region				Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Invest in new technologies	65%	68%	63%	66%	65%	61%	74%
Avoid investments in new technologies	20%	19%	21%	18%	22%	25%	13%
Don't know	14%	14%	16%	16%	13%	15%	14%

	Consumption Quartiles				LEAP/OESP Qualification		
	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Invest in new technologies	64%	67%	67%	64%	60%	71%	72%
Avoid investments in new technologies	20%	19%	19%	24%	23%	15%	19%
Don't know	17%	14%	14%	12%	17%	14%	9%

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Residential Customers

Specific Investments

Online Survey

Specific Investments – System Monitoring

Now let's turn to our final topic – specific investment decisions that Entegrus would like your feedback on.

The first potential investment is in emerging technology to better monitor **Entegrus**' distribution system.

Specifically, **Entegrus** serves 17 communities and has thousands of trees across its service territory and in proximity to its lines.

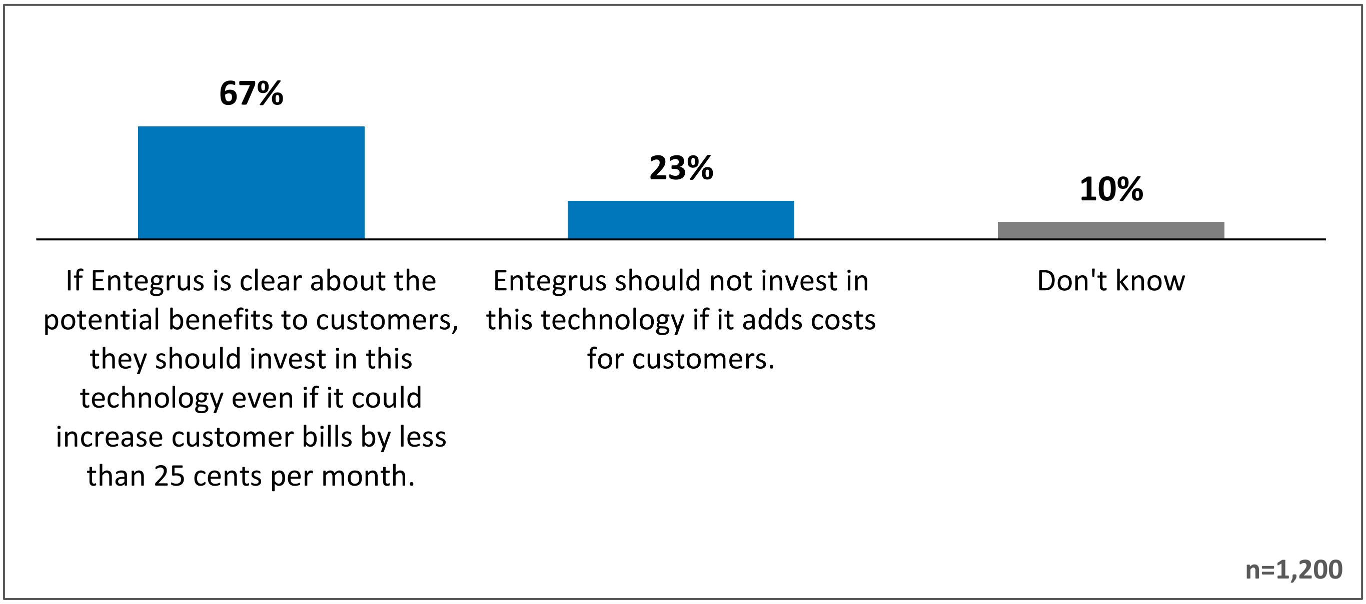
On a regular basis, **Entegrus** must ensure those trees remain a safe distance from electrical equipment like poles and wires. On a multi-year cycle, **Entegrus** goes community-by-community to trim trees and other vegetation. In a typical year, outages due to tree contacts account for approximately 7-19% of all customer outages.

New technology is emerging that would allow **Entegrus** to become more targeted in the trees that are selected for maintenance. This technology uses high resolution satellite imagery to build a 3D model of **Entegrus**' service territory and lines, allowing detailed measurements within centimeters.

This technology will allow precise planning for arborists that minimizes the magnitude of trimming required, but it would cost more upfront to implement.

While the benefits wouldn't be immediate, in the long-run, **Entegrus** believes that it could result in reducing the number of outages caused by tree contacts.

Q Regarding investments in technology to change the way **Entegrus** monitors and maintains trees and vegetation, which of the following best represents your view?



Online Survey

Specific Investments – System Monitoring

Residential

Q Regarding investments in technology to change the way **Entegrus** monitors and maintains trees and vegetation, which of the following best represents your view?

		Region				Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Should invest in this technology	67%	70%	64%	74%	65%	62%	77%
Should not invest in this technology	23%	21%	23%	19%	25%	29%	11%
Don't know	10%	10%	12%	7%	10%	9%	12%

	Consumption Quartiles				LEAP/OESP Qualification		
	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Should invest in this technology	68%	67%	66%	67%	64%	70%	73%
Should not invest in this technology	20%	23%	24%	24%	25%	20%	21%
Don't know	12%	10%	10%	9%	11%	10%	7%

Online Survey

Specific Investments – Demand Response

Residential

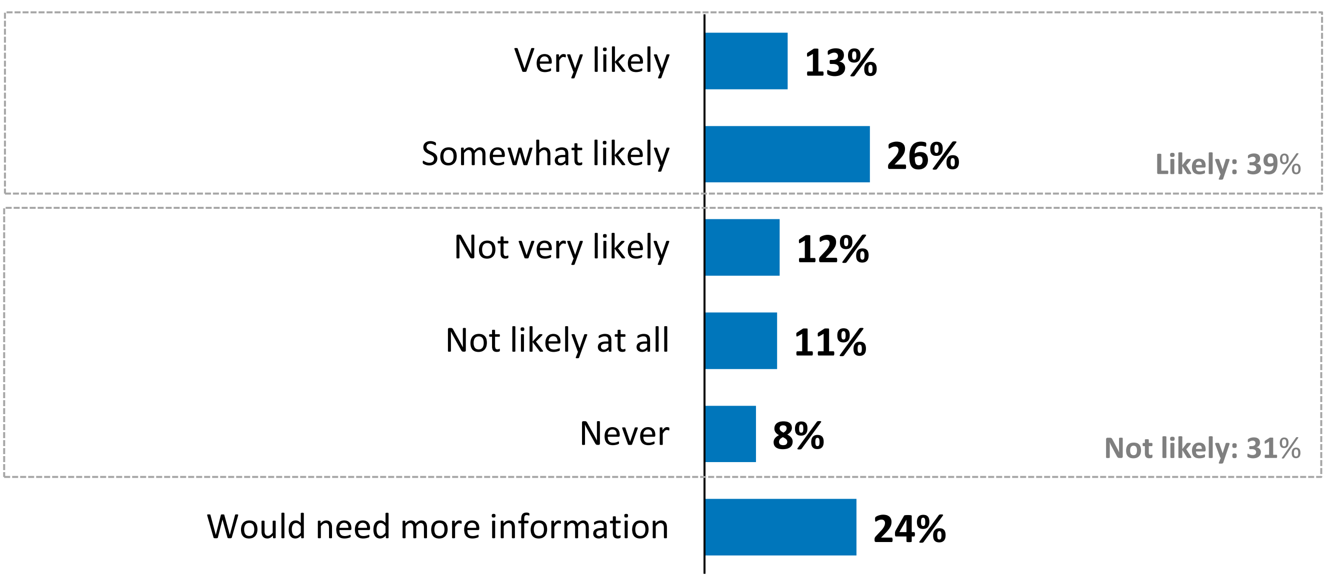
The second investment is in response to growing demand.

Electricity demand is on the rise across **Entegrus'** service territory. This increasing demand, resulting from industrial and residential growth, as well as the changing ways we use electricity, will require electricity companies like **Entegrus** to make significant investments in the grid.

One way to delay the need for system capacity upgrades is to offer incentives to customers for enrolling one or more of their energy intensive devices such as a furnace, air conditioner, hot water tank, pool pump, or electric vehicle charger with **Entegrus**.

For example, you could enrol your air conditioner and allow **Entegrus** to slightly modify its set point in the summer when demand for electricity is high.

Q If **Entegrus** were to introduce an **opt-in program** that offered incentives for enrolling one or more of your energy intensive devices, how likely would you be to enrol?



"Don't know" (6%) not shown.

n=1,200

Online Survey

Specific Investments – Demand Response

Residential

Q If **Entegrus** were to introduce an **opt-in program** that offered incentives for enrolling one or more of your energy intensive devices, how likely would you be to enrol?

	Region					Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very likely	13%	14%	15%	15%	10%	15%	9%
Somewhat likely	26%	26%	27%	24%	26%	25%	28%
Not very likely	12%	15%	10%	15%	9%	10%	15%
Not likely at all	11%	12%	9%	11%	13%	11%	12%
Never	8%	8%	7%	9%	10%	8%	8%
Would need more information	24%	21%	27%	17%	27%	24%	23%
Don't know	6%	5%	6%	8%	5%	6%	5%
Likely (Very + Somewhat)	**39%**	**40%**	**42%**	**39%**	**36%**	**40%**	**37%**
Not Likely (Not very likely + Not likely at all+ Never)	**31%**	**34%**	**26%**	**36%**	**32%**	**29%**	**35%**

Online Survey

Specific Investments – Demand Response

Residential

Q If **Entegrus** were to introduce an **opt-in program** that offered incentives for enrolling one or more of your energy intensive devices, how likely would you be to enrol?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very likely	13%	11%	14%	11%	16%	17%	12%	16%
Somewhat likely	26%	22%	29%	27%	26%	23%	30%	34%
Not very likely	12%	13%	14%	11%	10%	11%	14%	9%
Not likely at all	11%	12%	8%	14%	11%	9%	10%	12%
Never	8%	7%	8%	8%	9%	6%	8%	10%
Would need more information	24%	27%	22%	24%	22%	26%	23%	17%
Don't know	6%	7%	5%	5%	5%	8%	3%	2%
Likely (Very + Somewhat)	**39%**	**33%**	**43%**	**38%**	**43%**	**40%**	**42%**	**50%**
Not Likely (Not very likely + Not likely at all+ Never)	**31%**	**32%**	**30%**	**33%**	**30%**	**26%**	**32%**	**31%**

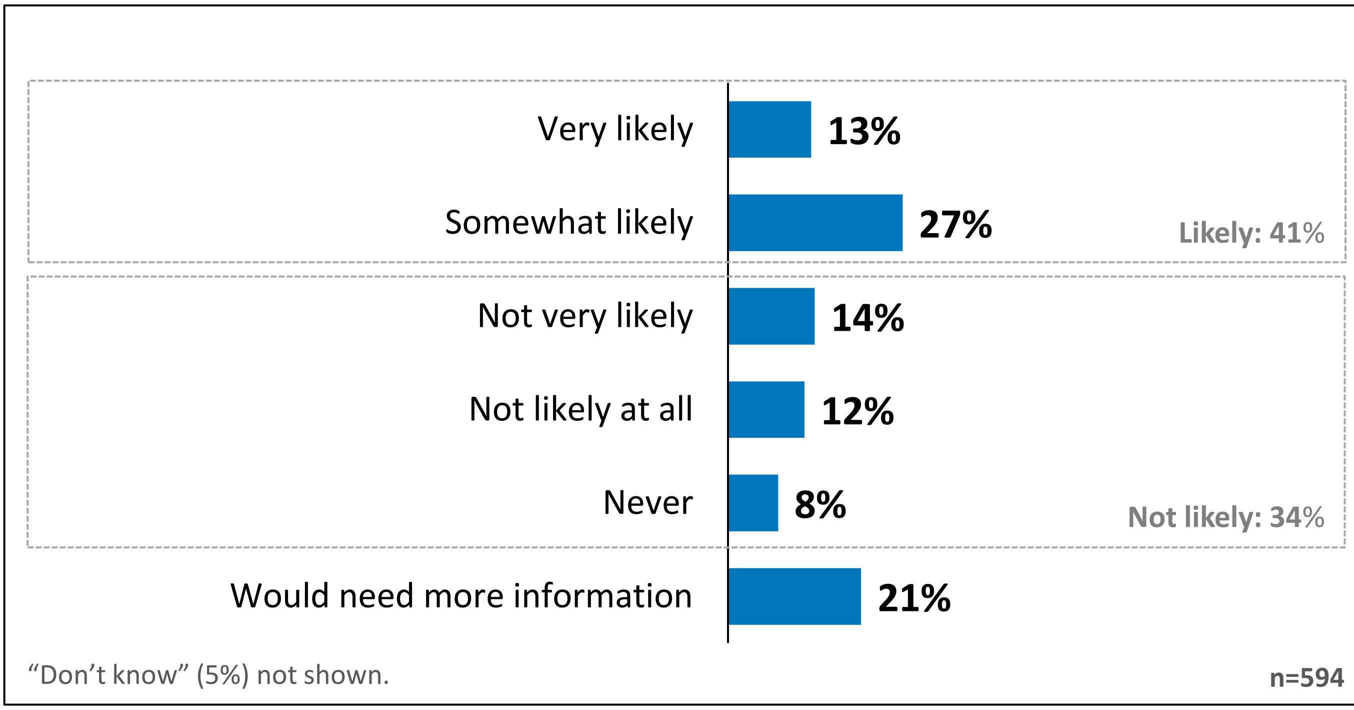
Online Survey

Specific Investments – Demand Response

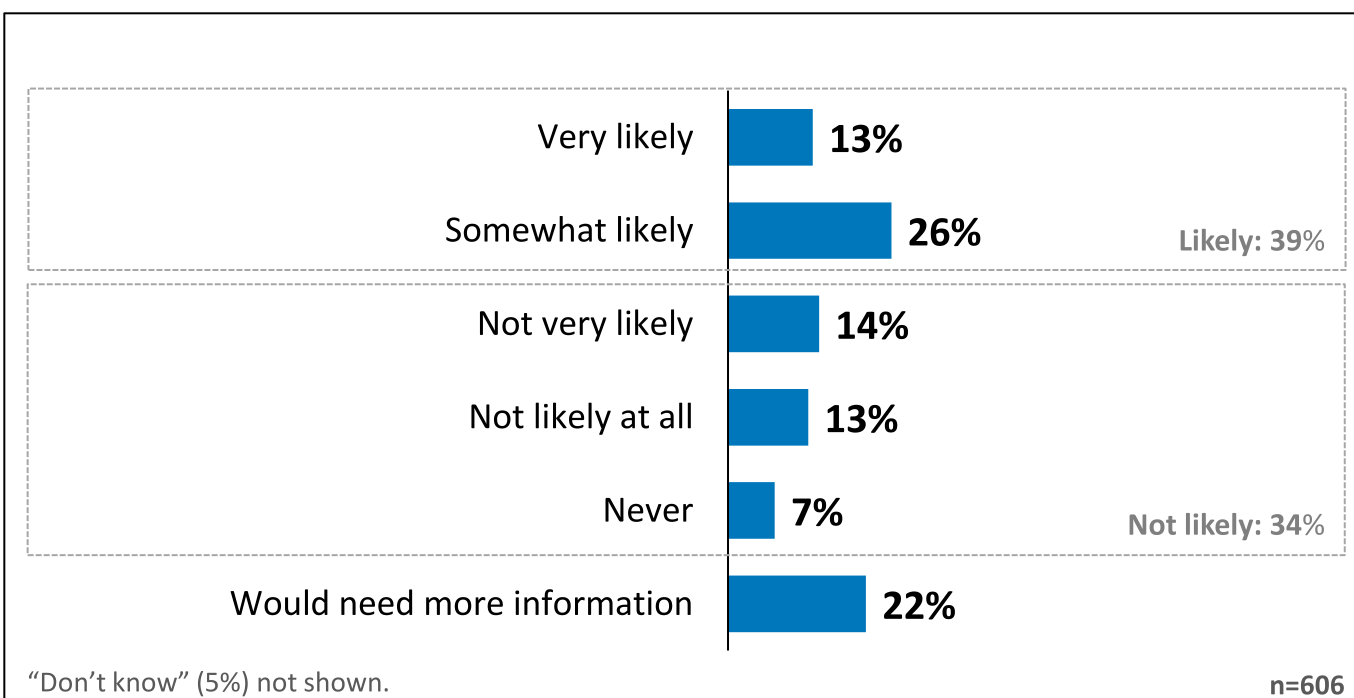
Residential

Q If Entegrus were to offer you **a one-time financial incentive of 50 dollars to participate/ 2 dollars for each month that you participate** in a program like this, how likely would you be to enrol?

A one-time financial incentive of 50 dollars to participate



2 dollars for each month that you participate



Online Survey

Specific Investments – Demand Response

Residential

Q

If Entegrus were to offer you **a one-time financial incentive of 50 dollars to participate** in a program like this, how likely would you be to enrol?

		Region				Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very likely	13%	13%	18%	8%	10%	15%	10%
Somewhat likely	27%	27%	27%	35%	27%	28%	27%
Not very likely	14%	17%	11%	11%	13%	12%	16%
Not likely at all	12%	12%	13%	11%	11%	10%	15%
Never	8%	7%	7%	9%	10%	8%	8%
Would need more information	21%	20%	19%	14%	26%	21%	20%
Don’t know	5%	5%	4%	11%	4%	6%	3%
Likely (Very + Somewhat)	**41%**	**40%**	**45%**	**43%**	**36%**	**43%**	**37%**
Not Likely (Not very likely + Not likely at all+ Never)	**34%**	**36%**	**32%**	**31%**	**34%**	**30%**	**39%**

Online Survey

Specific Investments – Demand Response

Residential

Q If Entegrus were to offer you **a one-time financial incentive of 50 dollars to participate** in a program like this, how likely would you be to enrol?

	Consumption Quartiles					LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very likely	13%	9%	15%	14%	15%	17%	16%	14%
Somewhat likely	27%	27%	32%	25%	27%	29%	29%	30%
Not very likely	14%	19%	12%	12%	12%	13%	17%	12%
Not likely at all	12%	10%	11%	15%	13%	6%	10%	15%
Never	8%	7%	8%	8%	9%	6%	9%	10%
Would need more information	21%	23%	18%	22%	21%	23%	18%	18%
Don't know	5%	6%	4%	5%	4%	7%	3%	2%
Likely (Very + Somewhat)	**41%**	**35%**	**46%**	**39%**	**42%**	**46%**	**45%**	**44%**
Not Likely (Not very likely + Not likely at all+ Never)	**34%**	**36%**	**31%**	**35%**	**33%**	**25%**	**35%**	**36%**

Online Survey

Specific Investments – Demand Response

Residential

Q If Entegrus were to offer you **2 dollars for each month that you participate** in a program like this, how likely would you be to enrol?

	Region					Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very likely	13%	11%	14%	17%	13%	15%	11%
Somewhat likely	26%	28%	25%	25%	24%	27%	24%
Not very likely	14%	16%	16%	12%	11%	12%	19%
Not likely at all	13%	13%	10%	13%	16%	13%	12%
Never	7%	7%	8%	9%	7%	6%	9%
Would need more information	22%	20%	22%	21%	23%	23%	19%
Don't know	5%	4%	5%	2%	7%	5%	6%
Likely (Very + Somewhat)	**39%**	**40%**	**40%**	**42%**	**36%**	**42%**	**34%**
Not Likely (Not very likely + Not likely at all+ Never)	**34%**	**36%**	**33%**	**34%**	**34%**	**31%**	**41%**

Online Survey

Specific Investments – Demand Response

Residential

Q If Entegrus were to offer you **2 dollars for each month that you participate** in a program like this, how likely would you be to enrol?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very likely	13%	12%	13%	9%	20%	17%	11%	17%
Somewhat likely	26%	24%	28%	26%	25%	25%	24%	34%
Not very likely	14%	14%	16%	14%	13%	12%	16%	9%
Not likely at all	13%	13%	6%	18%	14%	10%	12%	13%
Never	7%	7%	6%	11%	5%	5%	6%	9%
Would need more information	22%	24%	24%	19%	19%	23%	29%	15%
Don't know	5%	6%	6%	3%	4%	8%	2%	2%
Likely (Very + Somewhat)	**39%**	**35%**	**42%**	**35%**	**44%**	**41%**	**35%**	**51%**
Not Likely (Not very likely + Not likely at all+ Never)	**34%**	**34%**	**29%**	**42%**	**32%**	**28%**	**33%**	**32%**

Online Survey

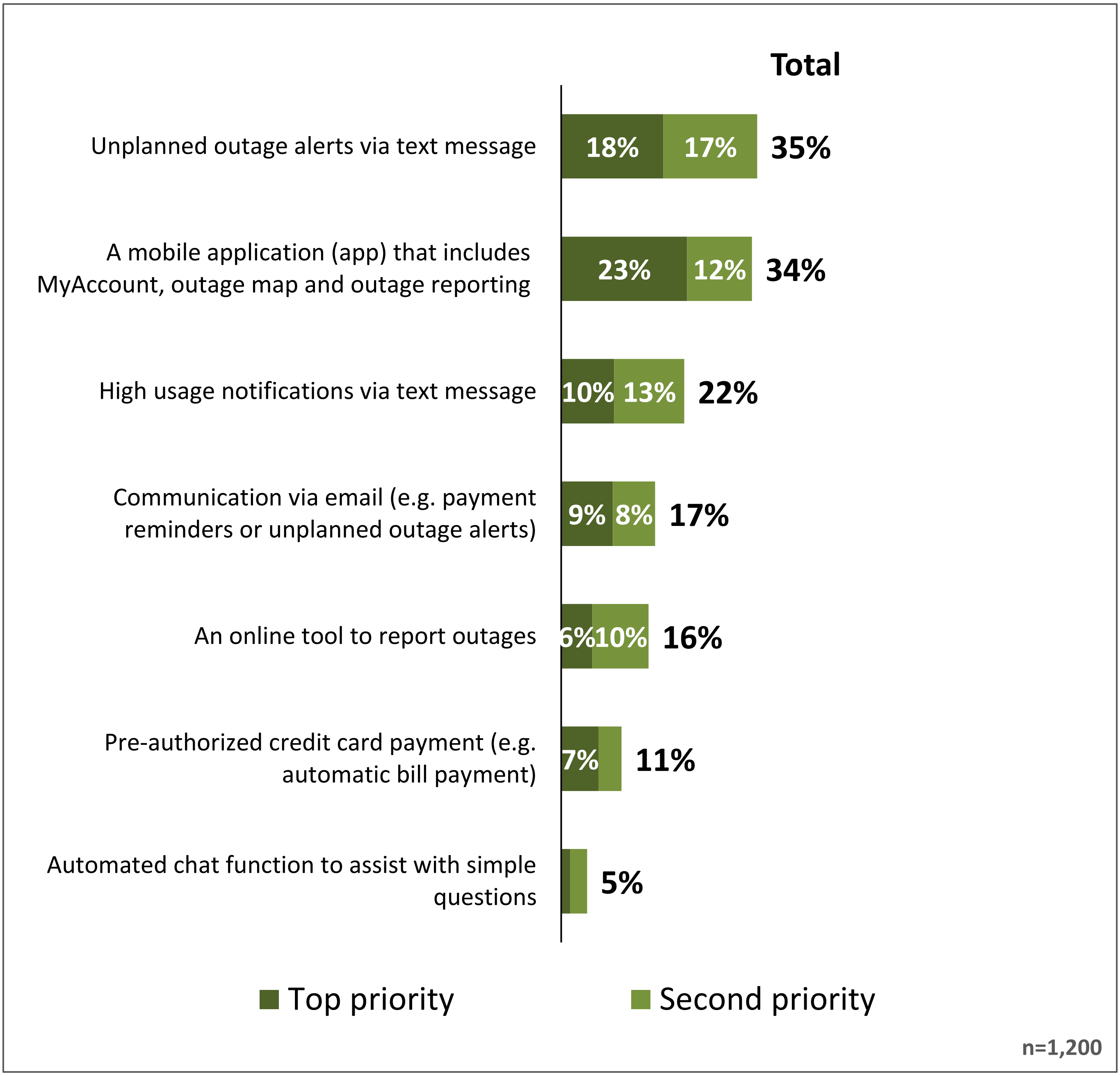
Residential

Specific Investments – Expanded Customer Service Offerings

The final series of investments are related to potential expanded customer service offerings.

There are several ways that **Entegrus** can expand its service offerings to customers. Of course, each of these expanded offerings come at a cost to customers.

Q Which of the following expanded customer service offerings would you be **most interested** in? And which would you be the next most interested in?



Note: Data labels are removed where 4% or less. "Don't know" and "None of the above" are not shown.

Online Survey

Specific Investments – Expanded Customer Service Offerings

Residential

Q Which of the following expanded customer service offerings would you be **most interested** in? And which would you be the next most interested in?

% who select as top 2 priority	Overall	Region				Bill Impact	
		Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Unplanned outage alerts via text message	35%	39%	33%	33%	34%	34%	38%
A mobile application (app)	34%	34%	36%	41%	31%	35%	34%
High usage notifications via text message	22%	21%	28%	17%	18%	24%	19%
Communication via email	17%	18%	15%	14%	18%	17%	16%
An online tool to report outages	16%	17%	9%	21%	20%	16%	15%
Pre-authorized credit card payment	11%	10%	13%	12%	9%	9%	14%
Automated chat function	5%	5%	5%	3%	5%	6%	2%

Note: Priority labels have been shortened for brevity. See slide 59 for full label text.
"Don't know" and "None of the above" are not shown.

Online Survey

Specific Investments – Expanded Customer Service Offerings

Residential

Q Which of the following expanded customer service offerings would you be **most interested** in? And which would you be the next most interested in?

% who select as top 2 priority		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Unplanned outage alerts via text message	35%	36%	32%	36%	37%	33%	36%	38%
A mobile application (app)	34%	26%	31%	36%	44%	28%	35%	47%
High usage notifications via text message	22%	18%	25%	22%	25%	21%	22%	27%
Communication via email	17%	20%	16%	18%	13%	20%	17%	14%
An online tool to report outages	16%	19%	13%	15%	16%	16%	21%	15%
Pre-authorized credit card payment	11%	12%	12%	10%	9%	9%	12%	15%
Automated chat function	5%	4%	6%	5%	4%	4%	6%	5%

Note: Priority labels have been shortened for brevity. See slide 59 for full label text.
"Don't know" and "None of the above" are not shown.

INNOVATIVE RESEARCH GROUP

Small Business Customers

Online Survey Results

Field Dates

The **Small Business Online Survey** was sent to a random selection of Entegrus Small Business customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **June 17th and July 8th, 2024**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the Small Business survey was sent to **1,539** customers from *engage@entegrus.com*. Reminder emails were sent on June 25th, July 2nd, and July 8th, 2024 to those who had not yet completed the survey.

Small Business Online Survey Completes

A total of **89** (unweighted) Entegrus Small Business customers completed the online survey.

Sample Weighting

The Small Business online survey sample was weighted to n=80 proportionately by collapsed consumption quartiles within region in order to be representative of the broader Entegrus customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by collapsed consumption quartile and region.

Region	Consumption Quartiles		Total
	Low-Medium (First + Second)	Medium-High (Third + Fourth)	
Chatham	15(10)	18 (13)	33 (23)
St. Thomas	9 (13)	10 (12)	19 (25)
Strathroy	2 (3)	2 (3)	4 (6)
Rest	21 (14)	12 (12)	33 (26)
Total	47 (41)	42 (39)	89 (80)

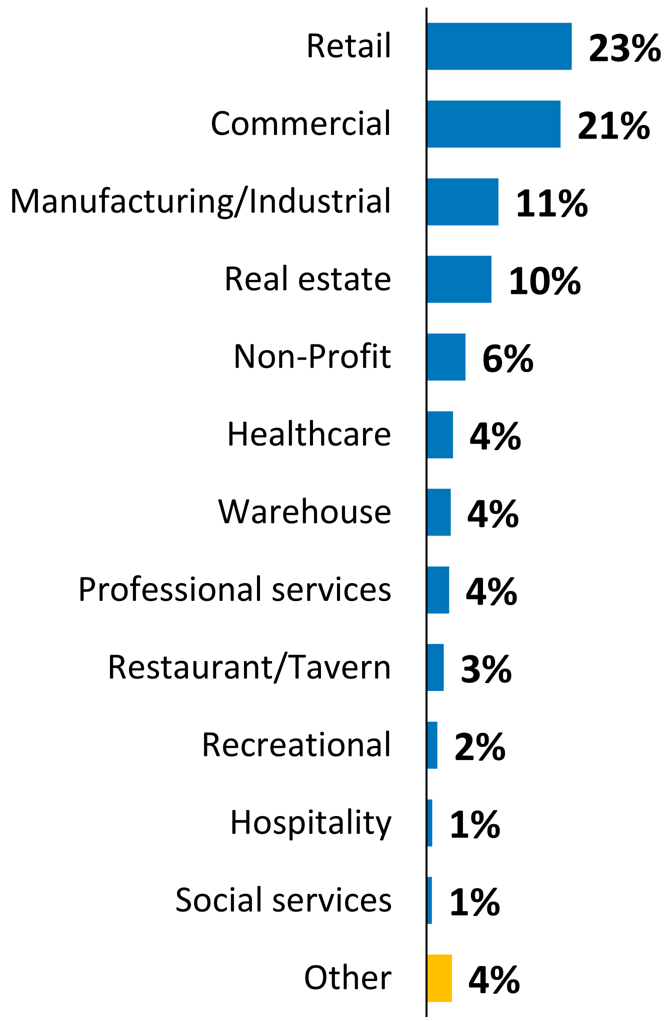
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Survey

Firmographic Breakdown

Small Business

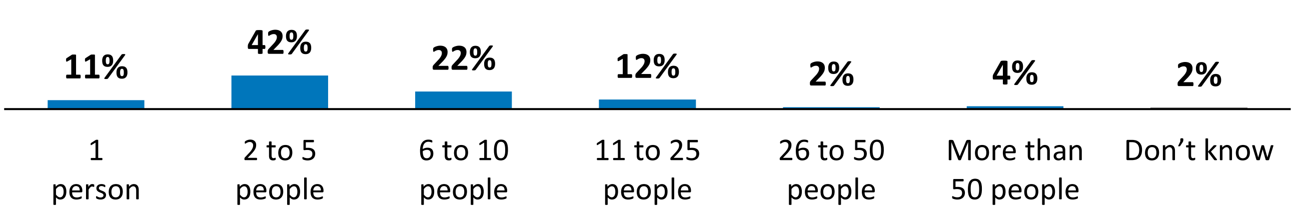
Q Business Sector



"Prefer not to say" (7%) not shown.

n=80

Q Business Size



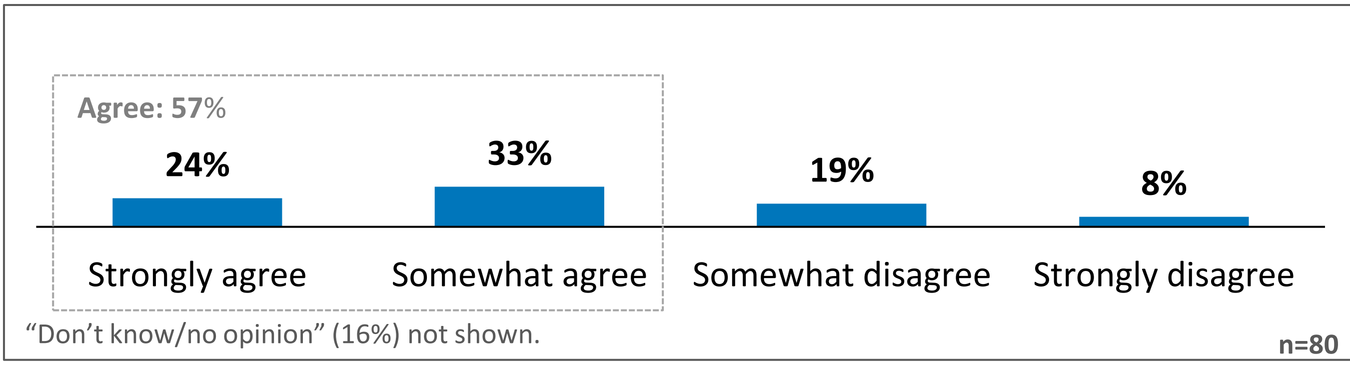
"Prefer not to say" (4%) not shown.

n=80

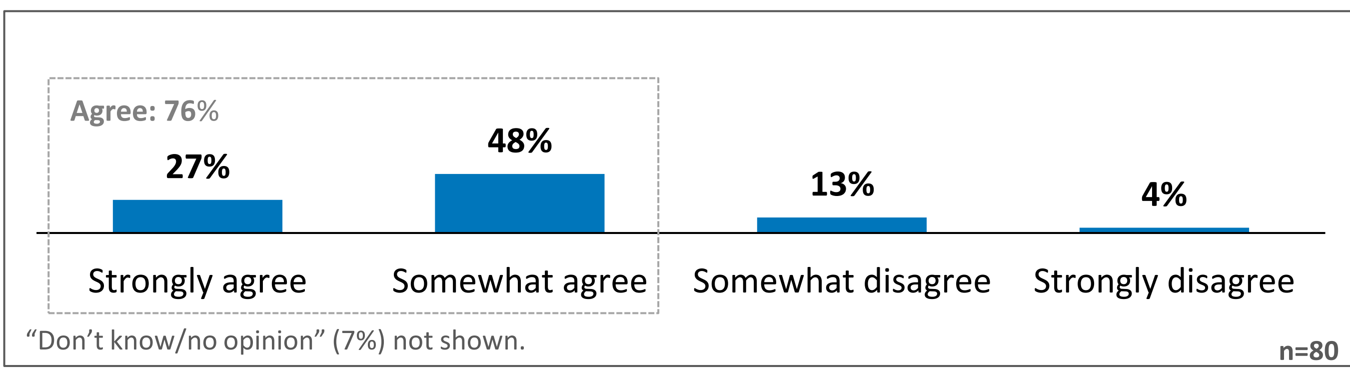
Online Survey
Environmental Controls

To what extent do you agree or disagree with the following statements?

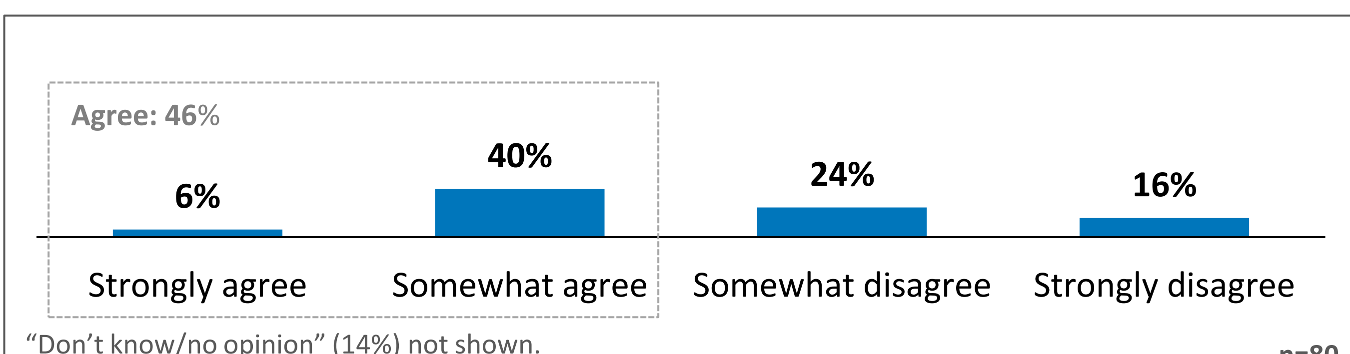
Q The cost of my organization’s electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



Q Customers are well-served by the electricity system in Ontario.



Q Customers are protected with respect to the price we pay for electricity.



Online Survey

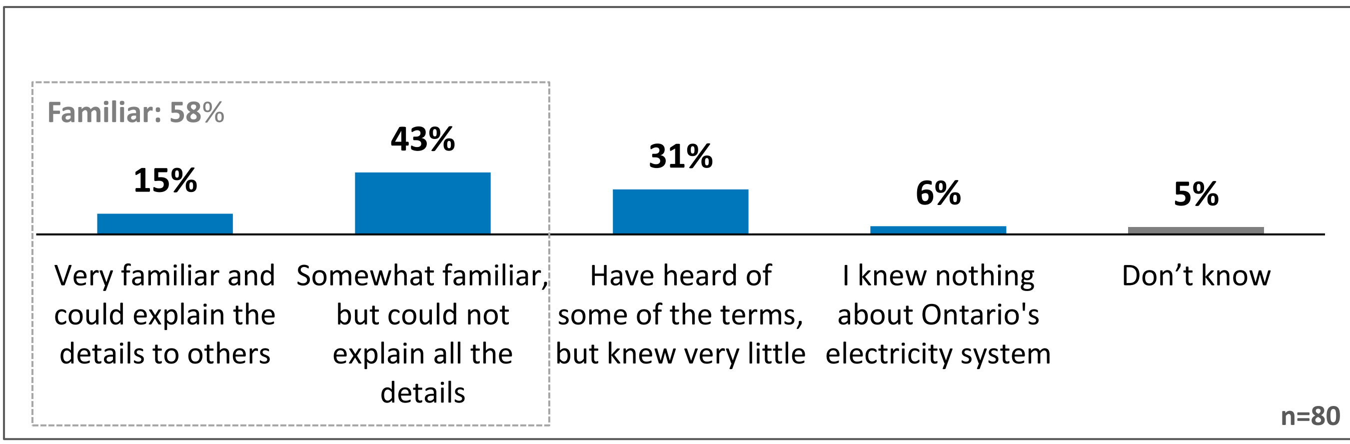
Familiarity with Ontario's Electricity System

Small Business

As you may know, Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province
- **Local distribution networks** take the electricity from provincial transmission lines and bring it to your home through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with the various parts of the electricity system and how they work together?



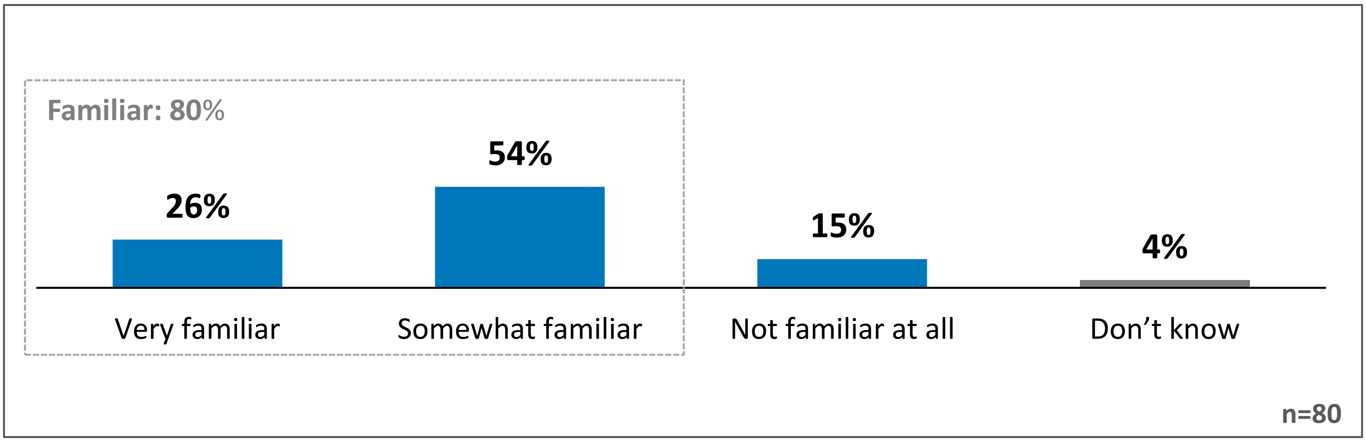
	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Very familiar	14%	15%	14%	15%
Somewhat familiar	41%	46%	44%	42%
Knew very little	35%	28%	29%	34%
Knew nothing	9%	3%	5%	7%
Don't know	2%	9%	7%	2%
Familiar (Very + Somewhat)	**55%**	**61%**	**59%**	**57%**

Online Survey
Familiarity with Entegrus

Small Business

Entegrus manages all aspects of the electricity distribution business throughout 17 communities in Southwestern Ontario. This is the network that takes the electricity from high-voltage transmission towers and brings it to your home or business through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with **Entegrus**, which operates the electricity distribution system in your community?



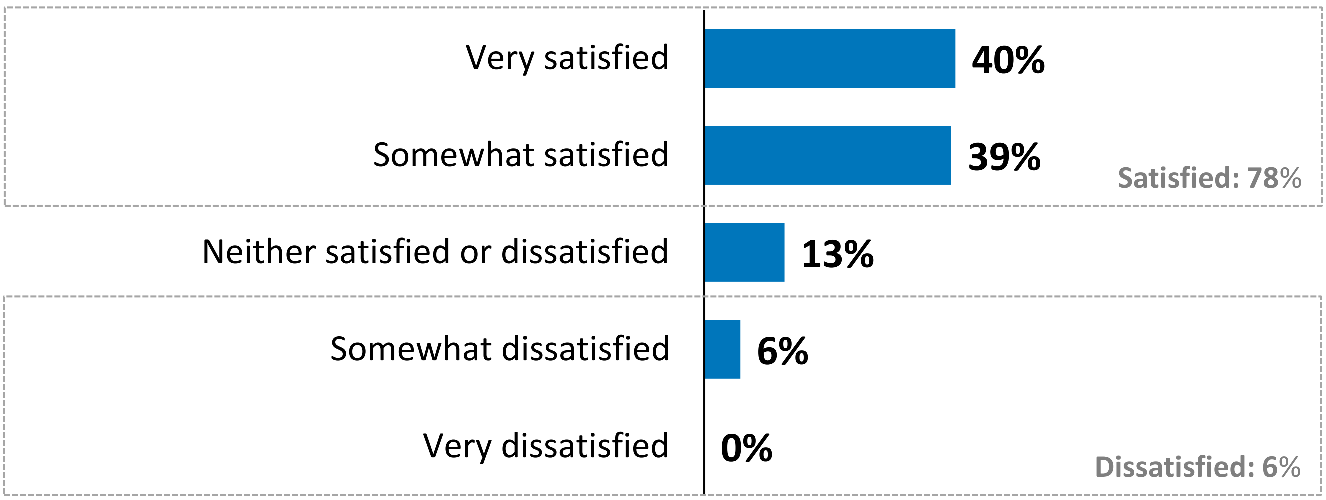
	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Very familiar	28%	24%	28%	24%
Somewhat familiar	48%	61%	47%	65%
Not familiar at all	23%	8%	18%	12%
Don't know	2%	7%	7%	--
Familiar (Very + Somewhat)	**75%**	**86%**	**74%**	**88%**

Online Survey

Overall Satisfaction with Entegrus

Small Business

Q Thinking specifically about the services provided to you and your community by **Entegrus**, overall, how satisfied or dissatisfied are you with the services that you receive?



"Don't know" (3%) not shown.

n=80

	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Very satisfied	36%	43%	41%	38%
Somewhat satisfied	37%	41%	35%	44%
Neither satisfied nor dissatisfied	19%	6%	12%	13%
Somewhat dissatisfied	9%	3%	7%	4%
Very dissatisfied	--	--	--	--
Don't know	--	7%	6%	--
Satisfied (Very + Somewhat)	**72%**	**85%**	**75%**	**82%**
Dissatisfied (Very + Somewhat)	**9%**	**3%**	**7%**	**4%**

Online Survey

How Entegrus can improve its services

Small Business

Q Is there anything in particular you would like **Entegrus** to do to improve its services to you?

Response	%
Improve customer service	5.0%
Lower rates/bills/too expensive	3.9%
Reduce delivery fee/service charges	2.6%
Improve reliability of service/reduce outages/disruptions	2.5%
Improve communication during outages	1.9%
Offer/improve green energy options	1.9%
Improve/update infrastructure (e.g. bury lines)	1.7%
Satisfied with services/no issues/complaints	0.9%
Other	0.9%
None/Don't know	78.8%

Note: Only responses >0.1% shown

Online Survey

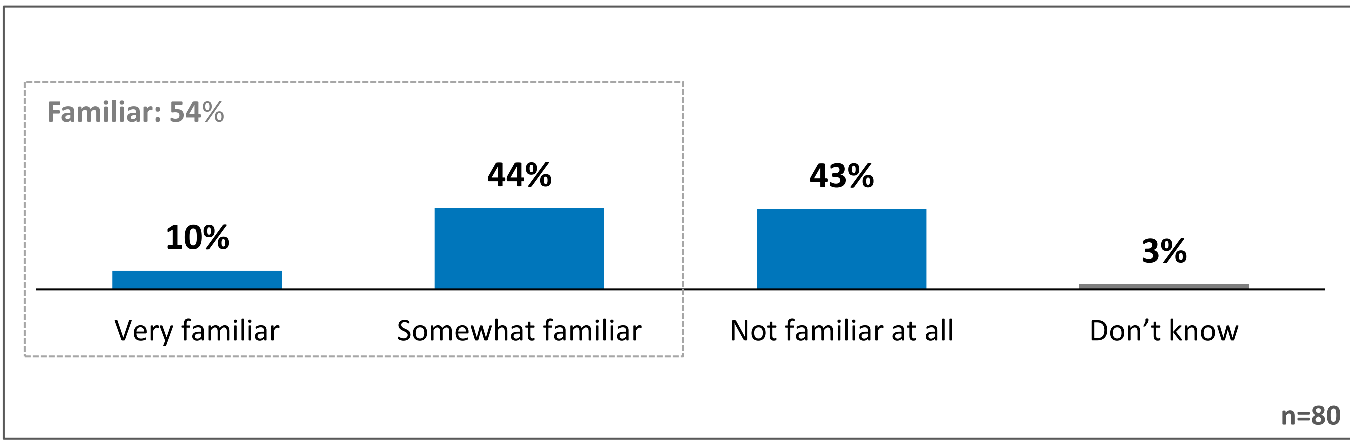
Bill Remittance Familiarity

While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – **Entegrus** retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.

Distribution makes up about **22%** of the typical small business customer's bill.

The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Entegrus**?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Very familiar	10%	10%	9%	12%
Somewhat familiar	45%	43%	46%	41%
Not familiar at all	43%	44%	41%	47%
Don't know	2%	4%	5%	--
Familiar (Very + Somewhat)	**55%**	**53%**	**54%**	**53%**

Small Business Customers

Priorities & Preferences

Online Survey
Importance of Customer Priorities

Small Business

Now, let's talk about our second topic – outcomes.

Everyday **Entegrus** interacts with hundreds of its customers through multiple channels and touchpoints, including surveys, the call centre and social media.

Through these ongoing interactions with customers, a number of company goals have been identified as priorities for **Entegrus**.

Shortened General Outcomes Priorities Response Labels	Full General Outcomes Priorities Response Labels
Delivering electricity at reasonable distribution rates	Delivering electricity at reasonable distribution rates
Ensuring reliable electrical service	Ensuring reliable electrical service
Investing in technology to withstand adverse weather	Investing in new technology that could lead to benefits such as better withstanding the impacts of adverse weather
Replacing aging infrastructure	Replacing aging infrastructure that is beyond its useful life
Quality customer service and communications	Providing quality customer service and enhanced communications
Helping customers with conservation and usage	Helping customers with conservation and changing their electricity usage
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure
Expanding grid to reduce impact on climate change	Expanding the electricity grid so that customers can reduce their impact on climate change by using electricity to replace fossil fuels (e.g., replacing gas-powered vehicles with electric vehicles or natural gas heating with heat pumps)
Enabling customers to access new electricity services	Enabling customers to access new electricity services (e.g., electricity storage, power walls and distributed generation, such as solar panels)

Online Survey

Importance of Customer Priorities

Small Business

Q Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Entegrus** priorities to you as a customer?

Delivering electricity at reasonable distribution rates [average = **9.2**]

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	0%	2%	0%	0%	0%	4%	0%	3%	6%	17%	67%	2%	**Extremely important**

Ensuring reliable electrical service [average = **9.2**]

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	0%	0%	0%	0%	0%	6%	0%	4%	10%	12%	66%	2%	**Extremely important**

Ensuring the safety of electricity infrastructure [average = **8.8**]

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	0%	0%	0%	0%	0%	8%	3%	9%	11%	14%	52%	2%	**Extremely important**

Quality customer service and communications [average = **8.3**]

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	1%	1%	3%	0%	1%	10%	4%	4%	13%	16%	44%	3%	**Extremely important**

Replacing aging infrastructure [average = **8.2**]

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	3%	0%	0%	1%	0%	10%	2%	8%	16%	19%	37%	3%	**Extremely important**

Note: Priority labels have been shortened for brevity. See slide 72 for full label text.
"Don't know" is not included in the calculation of means.

Online Survey

Importance of Customer Priorities (Cont'd)

Small Business

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Entegrus** priorities to you as a customer?

Investing in technology to withstand adverse weather [average = **7.7**]

	0	1	2	3	4	5	6	7	8	9	10	Don't know
	3%	1%	1%	2%	0%	13%	4%	11%	15%	16%	31%	4%

Not at all important (0) – **Extremely important** (10)

Helping customers with conservation and usage [average = **7.1**]

	0	1	2	3	4	5	6	7	8	9	10	Don't know
	2%	1%	1%	3%	2%	20%	7%	16%	17%	11%	20%	2%

Not at all important (0) – **Extremely important** (10)

Enabling customers to access new electricity services [average = **6.9**]

	0	1	2	3	4	5	6	7	8	9	10	Don't know
	5%	2%	3%	0%	0%	20%	9%	12%	17%	10%	20%	3%

Not at all important (0) – **Extremely important** (10)

Expanding grid to reduce impact on climate change [average = **5.8**]

	0	1	2	3	4	5	6	7	8	9	10	Don't know
	11%	1%	6%	2%	5%	24%	8%	11%	9%	10%	12%	2%

Not at all important (0) – **Extremely important** (10)

Note: Priority labels have been shortened for brevity. See slide 72 for full label text.
"Don't know" not included in calculation of means.

Online Survey

Importance of Customer Priorities – Average Scores

Small Business

Q Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Entegrus** priorities to you as a customer?

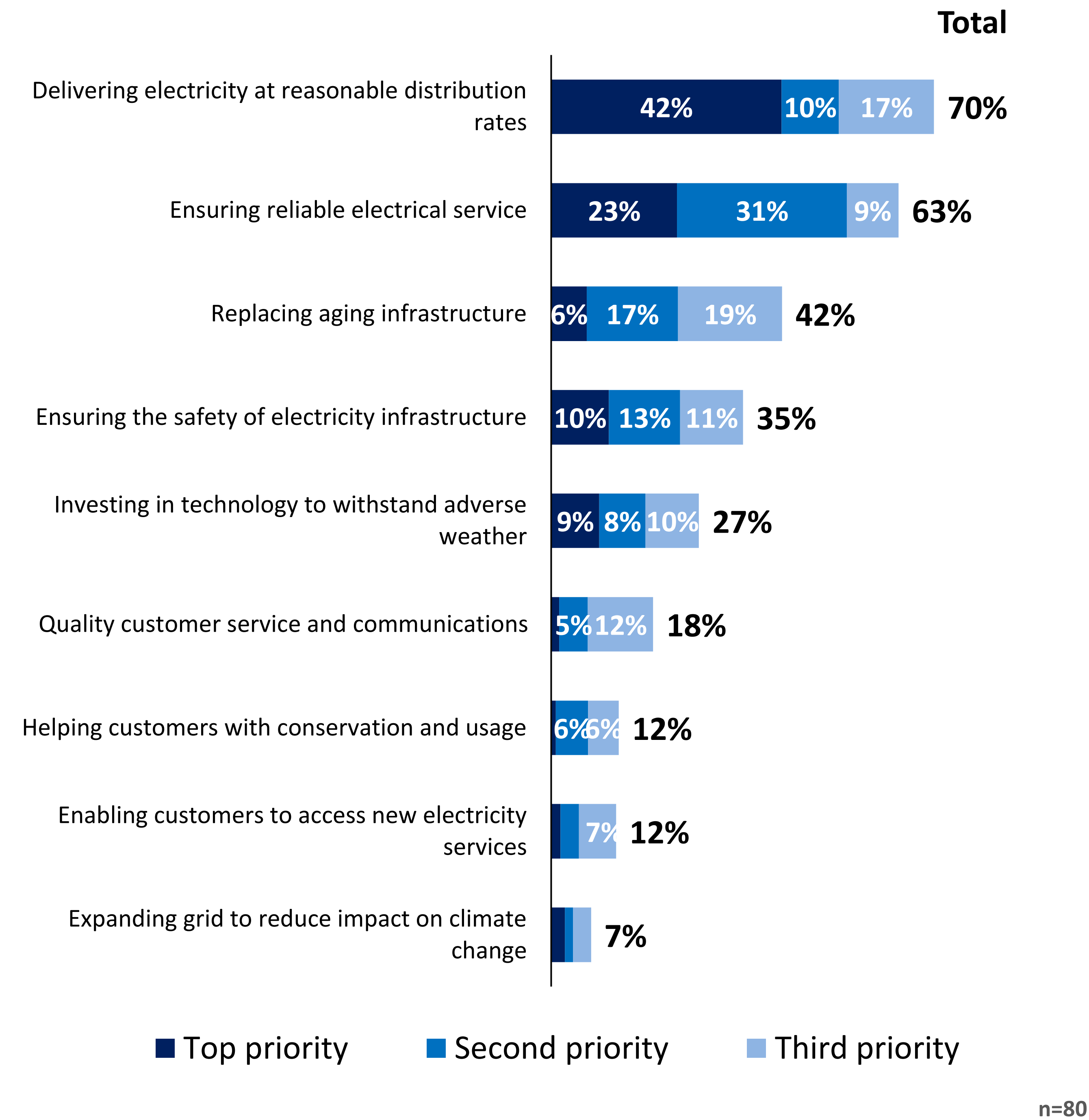
Average Score	Overall	Collapsed Consumption Quartiles: Low-Medium	Collapsed Consumption Quartiles: Medium-High	Bill Impact: Major Impact	Bill Impact: No Major Impact
Delivering electricity at reasonable distribution rates	9.2	9.0	9.4	9.5	8.9
Ensuring reliable electrical service	9.2	9.1	9.4	9.4	9.1
Ensuring the safety of electricity infrastructure	8.8	8.7	8.9	9.0	8.6
Quality customer service and communications	8.3	7.9	8.8	8.6	8.0
Replacing aging infrastructure	8.2	8.2	8.2	8.4	8.0
Investing in technology to withstand adverse weather	7.7	7.7	7.8	7.9	7.5
Helping customers with conservation and usage	7.1	6.7	7.6	7.6	6.5
Enabling customers to access new electricity services	6.9	6.7	7.2	7.7	6.0
Expanding grid to reduce impact on climate change	5.8	5.8	5.7	6.0	5.4

Note: Priority labels have been shortened for brevity. See slide 72 for full label text.
"Don't know" is not included in the calculation of means. "Don't know" not shown.

Online Survey
Ranking Customer Priorities

Small Business

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Entegrus** should focus on? And what do you consider the third most important priority?



Note: Priority labels have been shortened for brevity. See slide 72 for full label text. Data labels are removed where 4% or less. "Don't know" is not shown.

Online Survey

Ranking Customer Priorities – Summary

Small Business

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Entegrus** should focus on? And what do you consider the third most important priority?

% who select as top 3 priority		Collapsed Consumption Quartiles		Bill Impact	
	Overall	Low-Medium	Medium-High	Major Impact	No Major Impact
Delivering electricity at reasonable distribution rates	70%	70%	69%	70%	69%
Ensuring reliable electrical service	63%	72%	53%	63%	64%
Replacing aging infrastructure	42%	46%	38%	44%	40%
Ensuring the safety of electricity infrastructure	35%	31%	39%	31%	39%
Investing in technology to withstand adverse weather	27%	22%	31%	26%	27%
Quality customer service and communications	18%	8%	29%	17%	20%
Helping customers with conservation and usage	12%	10%	14%	18%	5%
Enabling customers to access new electricity services	12%	19%	5%	15%	8%
Expanding grid to reduce impact on climate change	7%	9%	6%	8%	6%

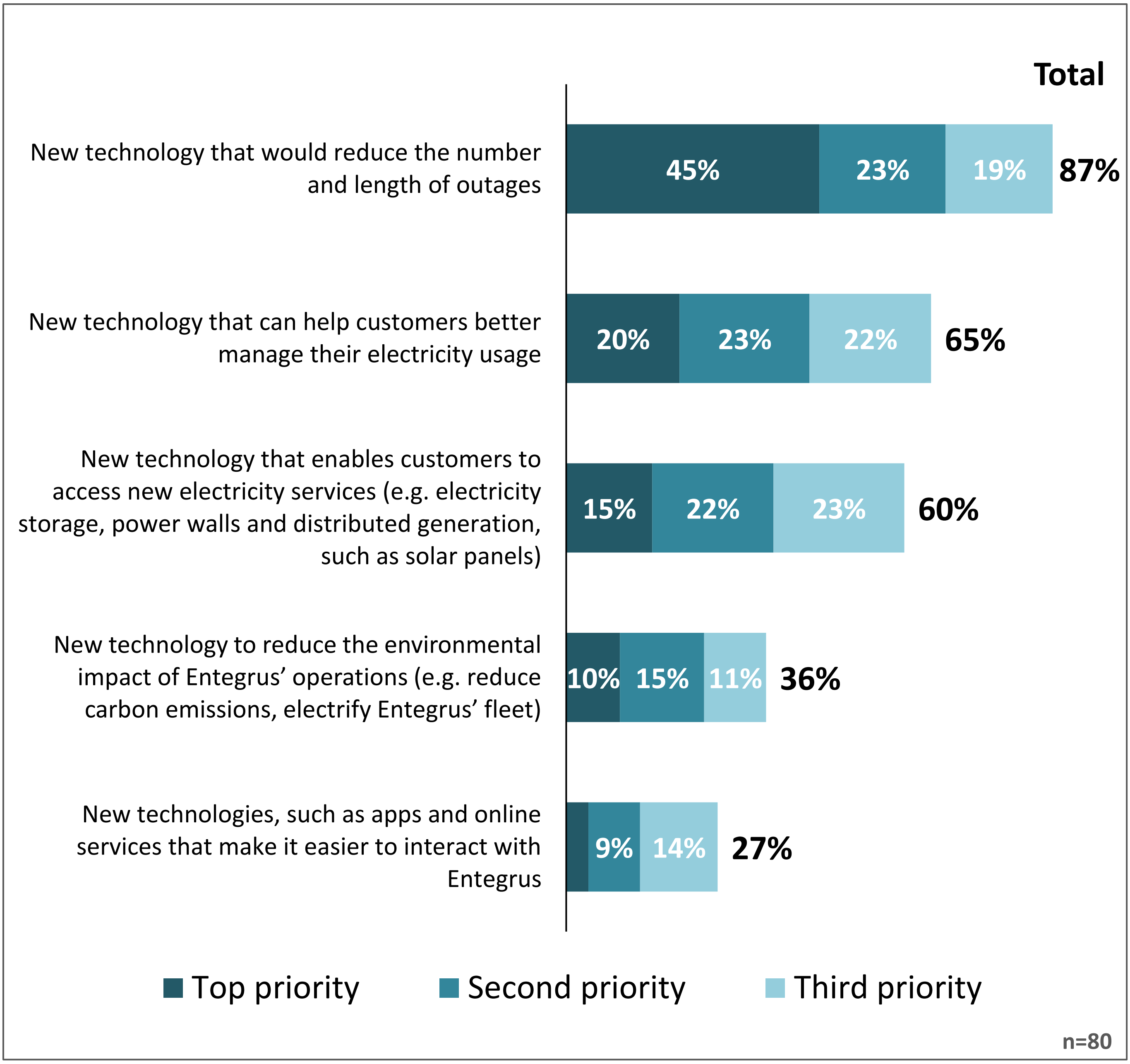
Note: Priority labels have been shortened for brevity. See slide 72 for full label text. "Don't know" is not shown.

Online Survey
Ranking Investments in New Technology

Small Business

Investments in new technology can help **Entegrus** address a range of issues. These include reliability, efficiency, customer service, **Entegrus'** impact on the environment, new service offerings and tools to manage electricity usage.

Q Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Entegrus** should focus on? And what do you consider the third most important priority?



Note: Data labels are removed where 4% or less. "Don't know" not shown.

Online Survey

Ranking Investments in New Technology – Summary

Small Business

Q

Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Entegrus** should focus on? And what do you consider the third most important priority?

% who select as top 3 priority	Collapsed Consumption Quartiles			Bill Impact	
	Overall	Low-Medium	Medium-High	Major Impact	No Major Impact
New technology that would reduce the number and length of outages	87%	86%	88%	89%	84%
New technology that can help customers better manage their electricity usage	65%	69%	61%	70%	59%
New technology that enables customers to access new electricity services	60%	64%	57%	61%	59%
New technology to reduce the environmental impact of Entegrus' operations	36%	36%	35%	32%	40%
New technologies, such as apps and online services that make it easier to interact with Entegrus	27%	22%	32%	29%	24%

Note: Priority labels have been shortened for brevity. See slide 78 for full label text. "Don't know" is not shown.

Online Survey
Additional Priority Areas

Small Business

Q Can you think of any other important priorities that **Entegrus** should be focusing on?

Response	%
Reducing costs for customers	4.3%
Updating aging infrastructure	2.8%
Address climate change/environment/renewable energy	1.9%
No issues/other priorities	1.4%
Proactive planning/action for the future	1.2%
Community involvement	0.9%
Line maintenance	0.8%
Electric vehicle (EV) infrastructure investment	0.8%
Efficient business practices	0.8%
Other	0.8%
None/Don't know	84.2%

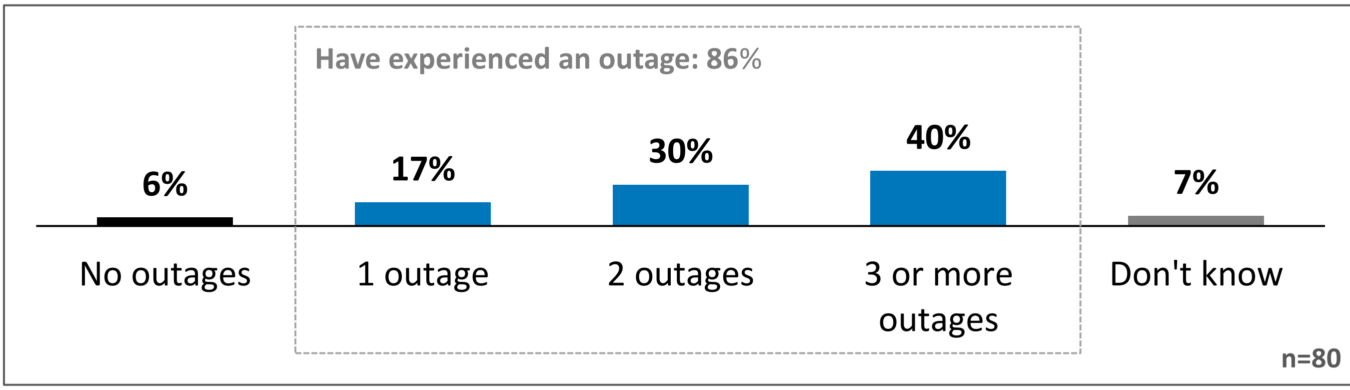
Note: Only responses >0.1% shown

Online Survey
Reliability Experience

Small Business

Now, let's talk about the reliability of electricity service your organization receives.

Q Have you experienced any power outages at **your organization in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
No outages	3%	9%	6%	6%
1 outage	14%	20%	12%	23%
2 outages	30%	29%	37%	21%
3 or more outages	48%	32%	34%	47%
Don't know	5%	10%	11%	3%
Have experienced at least 1 outage	**92%**	**81%**	**83%**	**91%**

INNOVATIVE RESEARCH GROUP

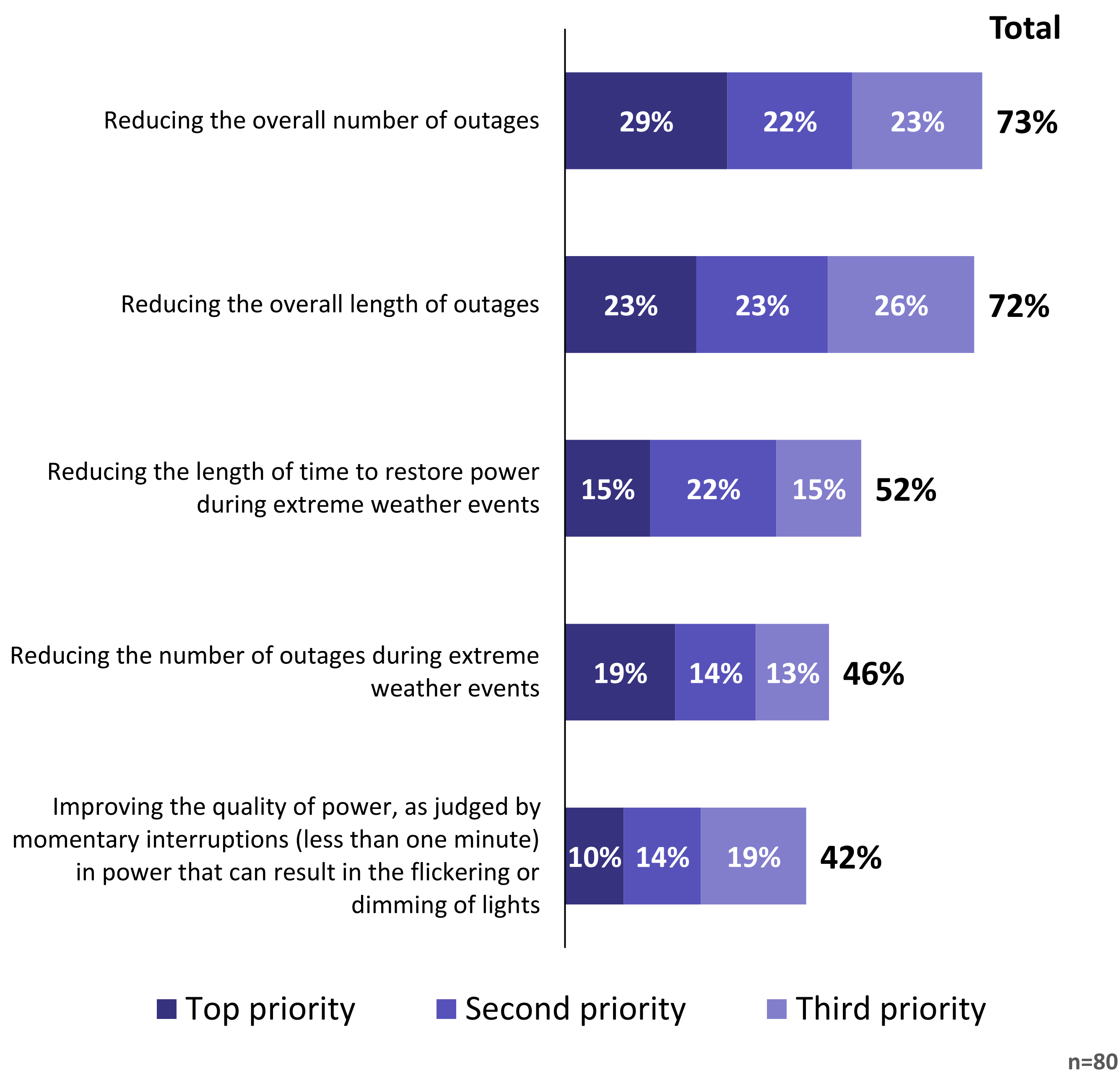
Online Survey

Ranking Reliability Preferences

Small Business

Q

When it comes to reliability, there are a number of areas that **Entegrus** can focus on. Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Entegrus** should focus on? And what do you consider the third most important priority?



Note: “Don’t know” not shown.

Online Survey

Ranking Reliability Preferences – Summary

Small Business

Q

When it comes to reliability, there are a number of areas that **Entegrus** can focus on. Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Entegrus** should focus on? And what do you consider the third most important priority?

% who select as top 3 priority		**Collapsed Consumption Quartiles**		**Bill Impact**	
	Overall	Low-Medium	Medium-High	Major Impact	No Major Impact
Reducing the overall number of outages	73%	80%	67%	71%	76%
Reducing the overall length of outages	72%	69%	75%	74%	70%
Reducing the length of time to restore power during extreme weather events	52%	48%	56%	49%	56%
Reducing the number of outages during extreme weather events	46%	50%	43%	43%	51%
Improving the quality of power, as judged by momentary interruptions	42%	43%	42%	44%	40%

Note: Priority labels have been shortened for brevity. See slide 82 for full label text. "Don't know" is not shown.

Innovative Research Group

Small Business Customers

Investment Trade-Offs

Online Survey

Investment Trade-Offs – System Renewal

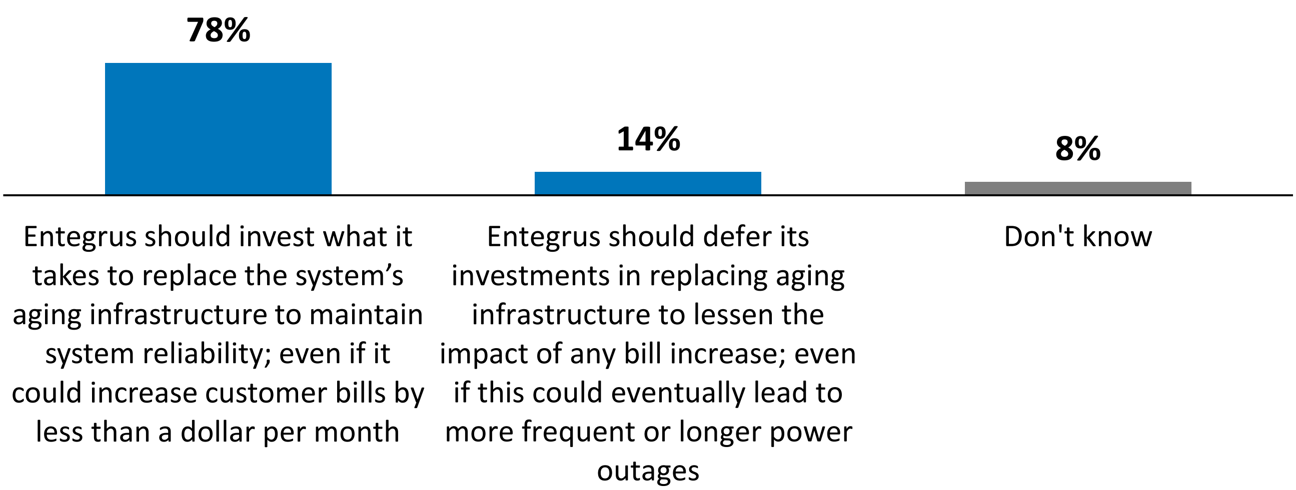
Now let's turn to our third topic – investment trade-offs.

Entegrus is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to know your preferences when it comes to finding the right balance between costs and other outcomes.

There are three investment categories that we would like to discuss.

The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

Q Regarding investments in aging infrastructure, which of the following statements best represents your point of view?



n=80

	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Invest what it takes	76%	80%	75%	83%
Defer investments	17%	10%	15%	12%
Don't know	7%	9%	10%	6%

Online Survey

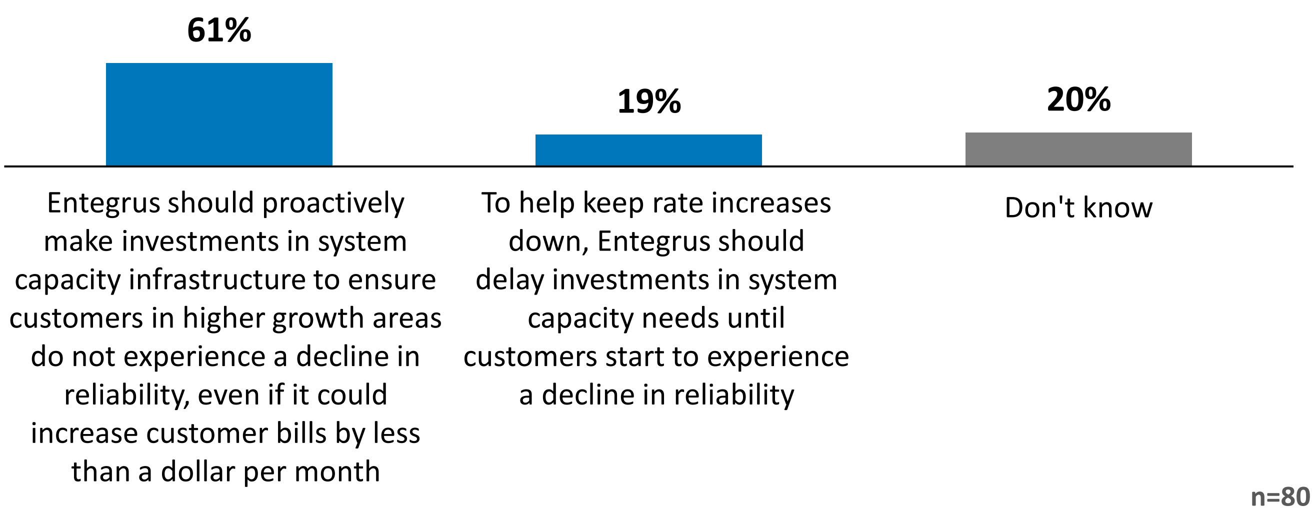
Investment Trade-Offs – System Service

Small Business

The second investment category focuses on growth and greater demand for electricity in various parts of **Entegrus'** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

Q With this in mind, which of the following statements best represents your point of view?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Proactive investments in system capacity	62%	60%	65%	56%
Delay capacity investments until reliability declines	24%	13%	18%	19%
Don't know	14%	27%	17%	24%

INNOVATIVE RESEARCH GROUP

Online Survey

Investment Trade-Offs – Grid Modernization

Small Business

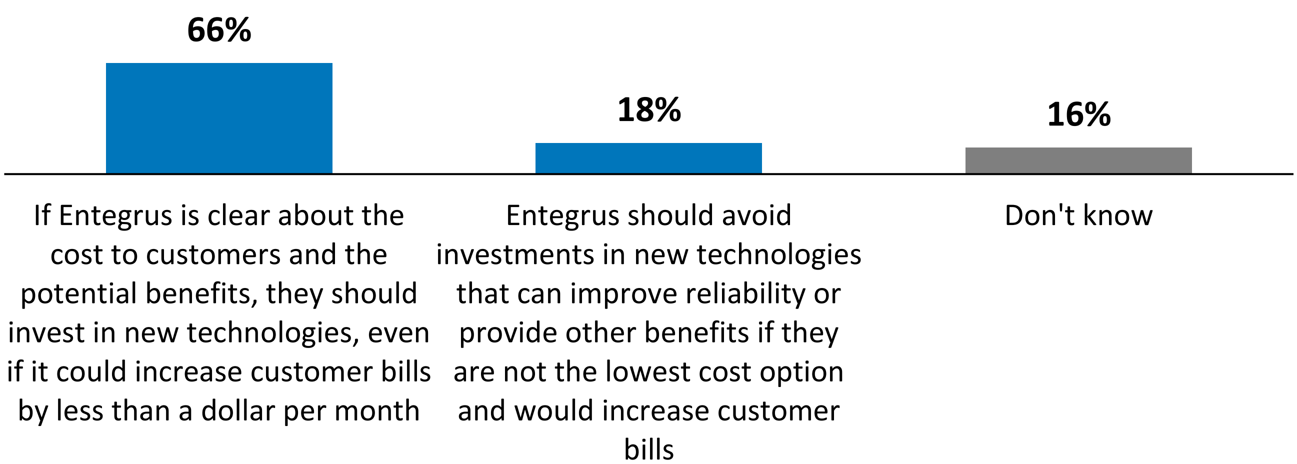
Entegrus can invest in technology that can lead to a wide range of benefits including reliability, efficiency, customer service, and reducing environmental impacts.

Entegrus generally invests in technology when it provides equal or improved service at the least cost.

However, there are times when **Entegrus** identifies *new* technology that <u>can improve reliability or provide other benefits, but it will cost customers more</u>.

For instance, advanced customer meters that can measure when different appliances or equipment are running, allowing **Entegrus** to provide customers with better advice on how to reduce their energy consumption and costs.

Q Regarding these types of investments, which of the following best represents your view?



n=80

	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Invest in new technologies	64%	68%	68%	63%
Avoid investments in new technologies	24%	13%	22%	14%
Don't know	12%	20%	10%	23%

Small Business Customers

Specific Investments

Online Survey

Specific Investments – System Monitoring

Small Business

Now let's turn to our final topic – specific investment decisions that Entegrus would like your feedback on.

The first potential investment is in emerging technology to better monitor **Entegrus**' distribution system.

Specifically, **Entegrus** serves 17 communities and has thousands of trees across its service territory and in proximity to its lines.

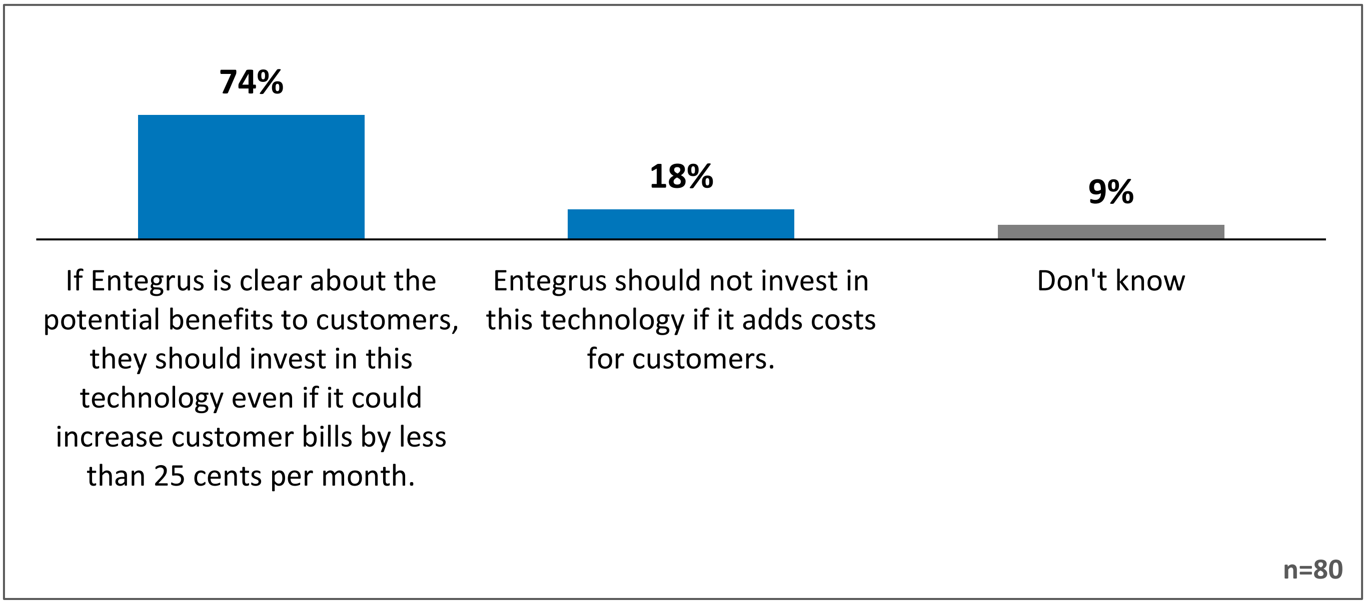
On a regular basis, **Entegrus** must ensure those trees remain a safe distance from electrical equipment like poles and wires. On a multi-year cycle, **Entegrus** goes community-by-community to trim trees and other vegetation. In a typical year, outages due to tree contacts account for approximately 7-19% of all customer outages.

New technology is emerging that would allow **Entegrus** to become more targeted in the trees that are selected for maintenance. This technology uses high resolution satellite imagery to build a 3D model of **Entegrus**' service territory and lines, allowing detailed measurements within centimeters.

This technology will allow precise planning for arborists that minimizes the magnitude of trimming required, but it would cost more upfront to implement.

While the benefits wouldn't be immediate, in the long-run, **Entegrus** believes that it could result in reducing the number of outages caused by tree contacts.

Q Regarding investments in technology to change the way **Entegrus** monitors and maintains trees and vegetation, which of the following best represents your view?



Online Survey

Specific Investments – System Monitoring

Small Business

Q Regarding investments in technology to change the way **Entegrus** monitors and maintains trees and vegetation, which of the following best represents your view?

	Overall	Collapsed Consumption Quartiles: Low-Medium	Collapsed Consumption Quartiles: Medium-High	Bill Impact: Major Impact	Bill Impact: No Major Impact
Should invest in this technology	74%	71%	77%	72%	75%
Should not invest in this technology	18%	19%	16%	22%	13%
Don't know	9%	10%	7%	6%	12%

INNOVATIVE RESEARCH GROUP

Online Survey

Specific Investments – Demand Response

Small Business

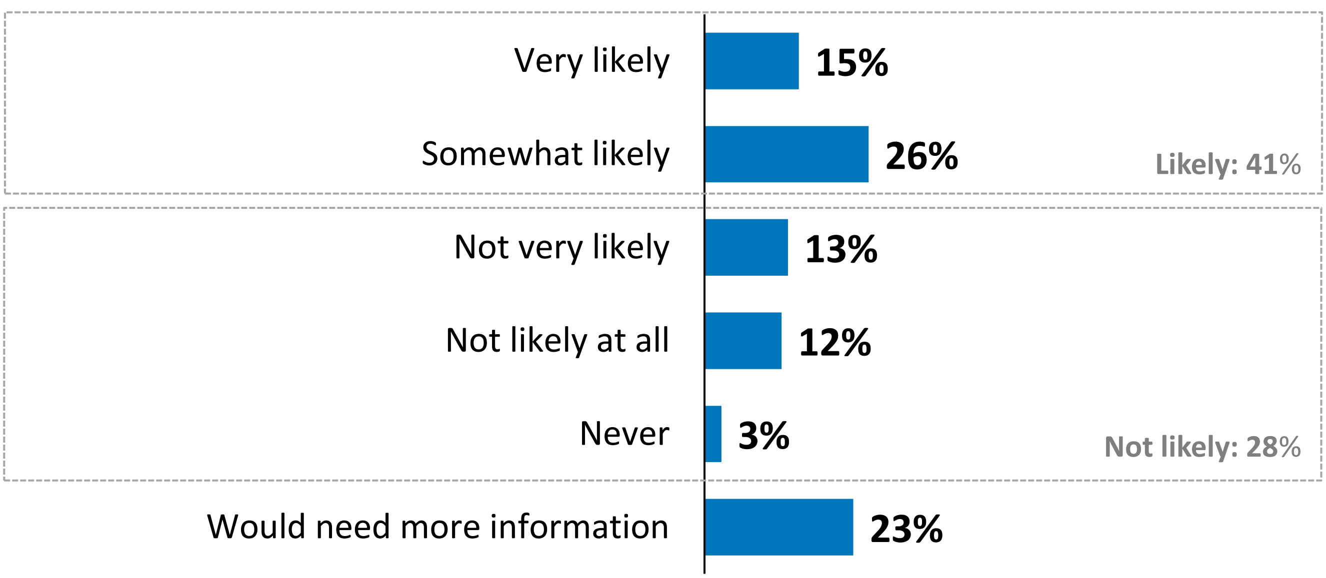
The second investment is in response to growing demand.

Electricity demand is on the rise across **Entegrus'** service territory. This increasing demand, resulting from industrial and residential growth, as well as the changing ways we use electricity, will require electricity companies like **Entegrus** to make significant investments in the grid.

One way to delay the need for system capacity upgrades is to offer incentives to customers for reducing or shifting their electricity consumption at times of peak demand.

For example, this could include reducing the speed or power of equipment, or limiting the use of large equipment at times of peak demand

Q If **Entegrus** were to introduce an **opt-in program** that offered incentives for reducing or shifting electricity consumption at times of peak demand, how likely would you be to enrol?



"Don't know" (8%) not shown.

n=80

Online Survey

Specific Investments – Demand Response

Small Business

Q If **Entegrus** were to introduce an **opt-in program** that offered incentives for reducing or shifting electricity consumption at times of peak demand, how likely would you be to enrol?

		Collapsed Consumption Quartiles		Bill Impact	
	Overall	Low-Medium	Medium-High	Major Impact	No Major Impact
Very likely	15%	15%	14%	15%	14%
Somewhat likely	26%	25%	26%	29%	22%
Not very likely	13%	9%	18%	15%	11%
Not likely at all	12%	14%	11%	12%	12%
Never	3%	2%	4%	5%	--
Would need more information	23%	31%	15%	22%	25%
Don't know	8%	4%	12%	3%	15%
Likely (Very + Somewhat)	**41%**	**41%**	**40%**	**44%**	**37%**
Not Likely (Not very likely + Not likely at all+ Never)	**28%**	**24%**	**32%**	**32%**	**23%**

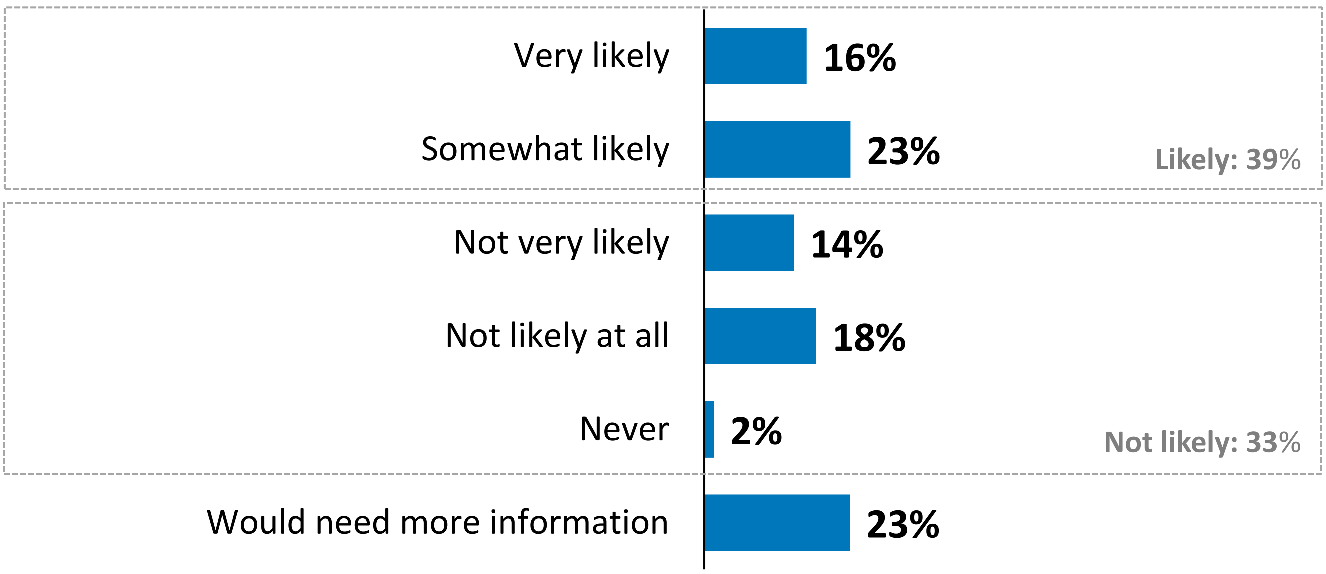
Online Survey

Specific Investments – Demand Response

Small Business

Q If Entegrus were to offer you **a one-time financial incentive of 75 dollars to participate/ 5 dollars for each month that you participate** in a program like this, how likely would you be to enrol?

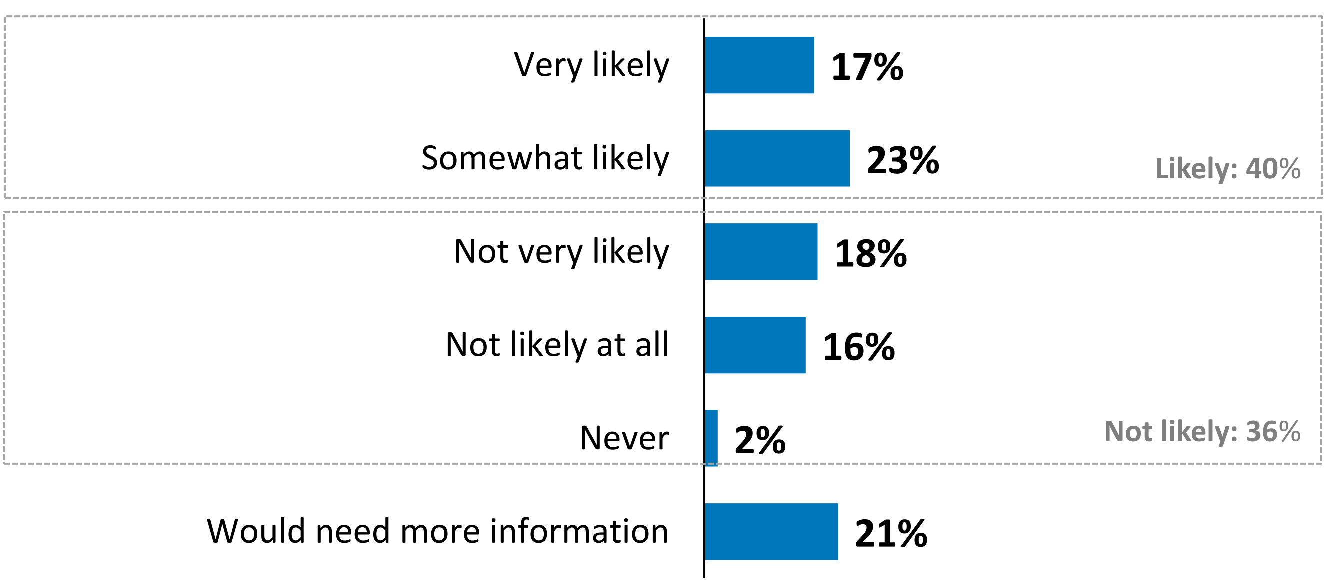
A one-time financial incentive of 75 dollars to participate



"Don't know" (5%) not shown.

n=46

5 dollars for each month that you participate



"Don't know" (3%) not shown.

n=34

Online Survey

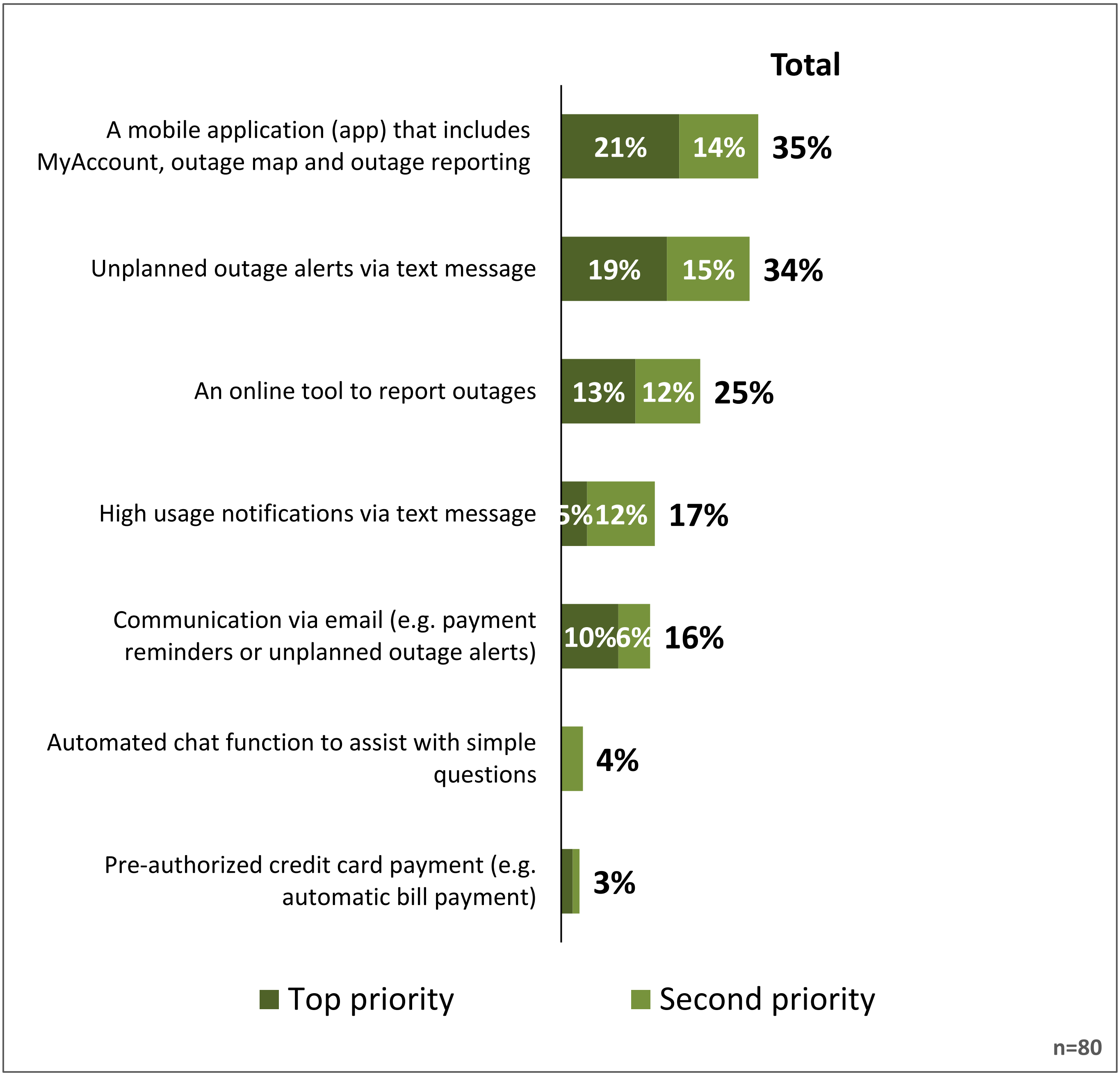
Small Business

Specific Investments – Expanded Customer Service Offerings

The final series of investments are related to potential expanded customer service offerings.

There are several ways that **Entegrus** can expand its service offerings to customers. Of course, each of these expanded offerings come at a cost to customers.

Q Which of the following expanded customer service offerings would you be **most interested** in? And which would you be the next most interested in?



Note: Data labels are removed where 4% or less. "Don't know" and "None" are not shown.

Online Survey

Small Business

Specific Investments – Expanded Customer Service Offerings

Q Which of the following expanded customer service offerings would you be **most interested** in? And which would you be the next most interested in?

% who select as top 2 priority	Overall	Collapsed Consumption Quartiles: Low-Medium	Collapsed Consumption Quartiles: Medium-High	Bill Impact: Major Impact	Bill Impact: No Major Impact
A mobile application (app)	35%	38%	33%	38%	33%
Unplanned outage alerts via text message	34%	43%	25%	34%	34%
An online tool to report outages	25%	28%	22%	21%	31%
High usage notifications via text message	17%	10%	24%	22%	10%
Communication via email	16%	12%	20%	16%	16%
Automated chat function	4%	2%	6%	2%	6%
Pre-authorized credit card payment	3%	2%	5%	2%	5%

Note: Priority labels have been shortened for brevity. See slide 94 for full label text.
"Don't know" and "None" are not shown.

Commercial & Industrial/Large Use Customers

Online Survey Results

Online Survey
Survey Design & Methodology

Field Dates

The **Commercial & Industrial/Large Use Online Survey** was sent to all Entegrus Commercial & Industrial/Large Use customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **July 10th and August 12th, 2024**.

Each customer received a unique URL that could be linked back to their average monthly demand, region and rate class.

In total, the Commercial & Industrial/Large Use survey was sent to **173** customers from *engage@entegrus.com*. Reminder emails were sent on July 17th, July 29th, August 6th, and August 12th, 2024 to those who had not yet completed the survey.

Commercial & Industrial Online Survey Completes

A total of **27** (unweighted) Entegrus Commercial & Industrial/Large Use customers completed the online survey.

Sample Weighting

Due to the small sample size (n=27), the Commercial & Industrial/Large Use results are not weighted and are presented in frequencies rather than percentages. Results should be interpreted as directional only.

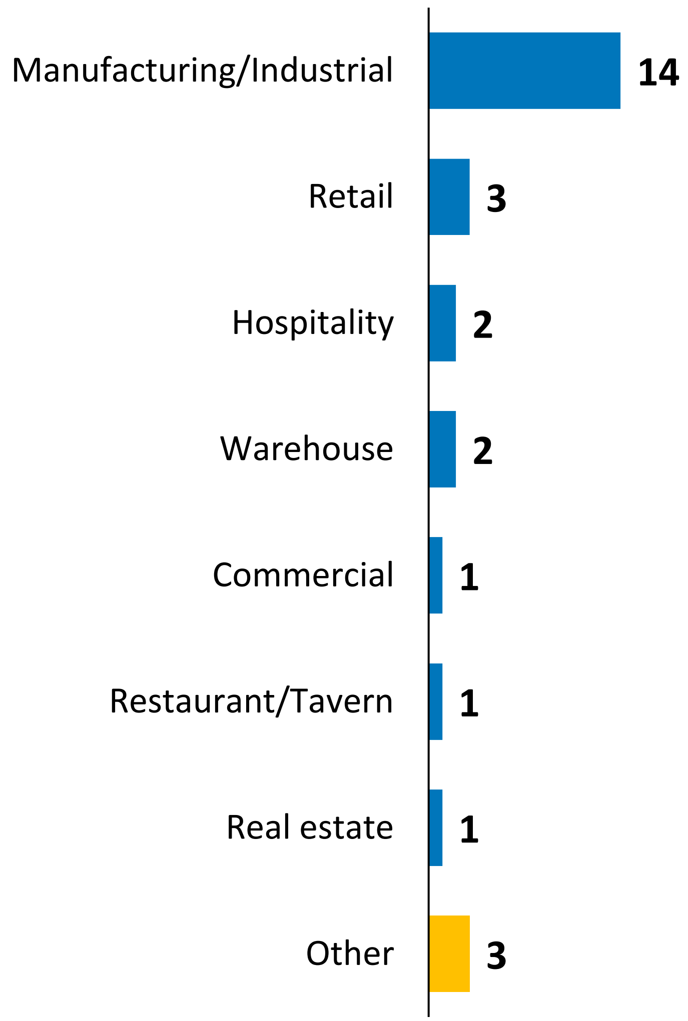
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Survey

Firmographic Breakdown

Commercial & Industrial

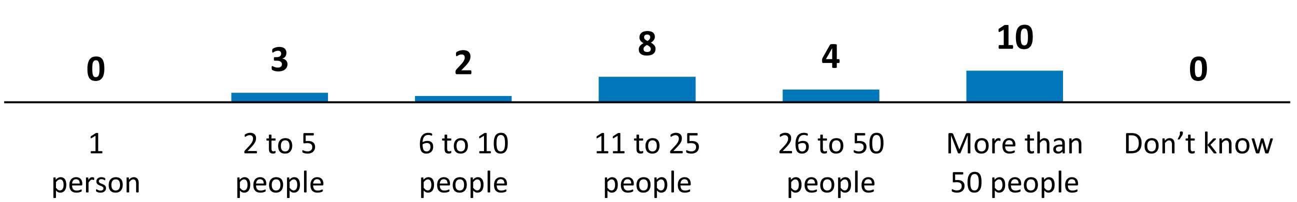
Q Organization Sector



"Prefer not to say" (0%) not shown.

n=27

Q Business Size



"Prefer not to say" (0%) not shown.

n=27

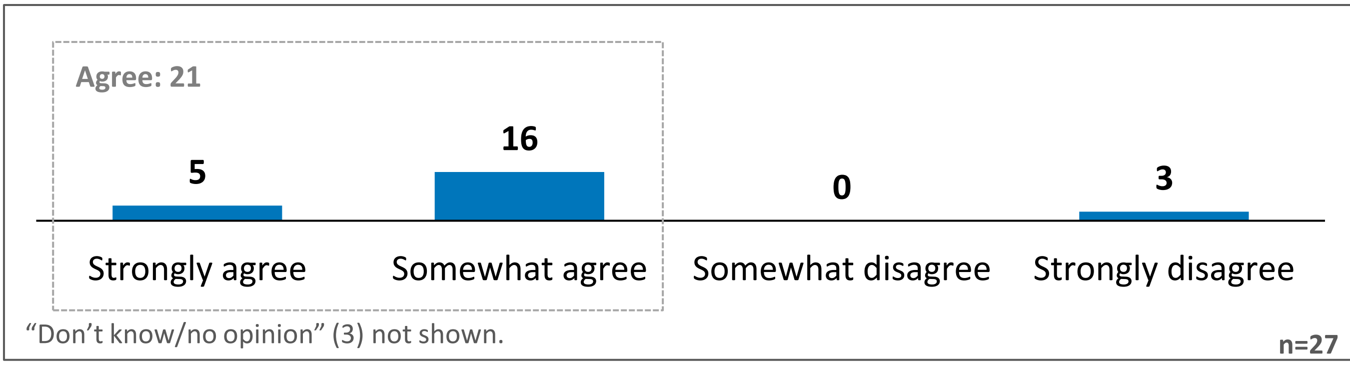
Online Survey

Environmental Controls

Commercial & Industrial

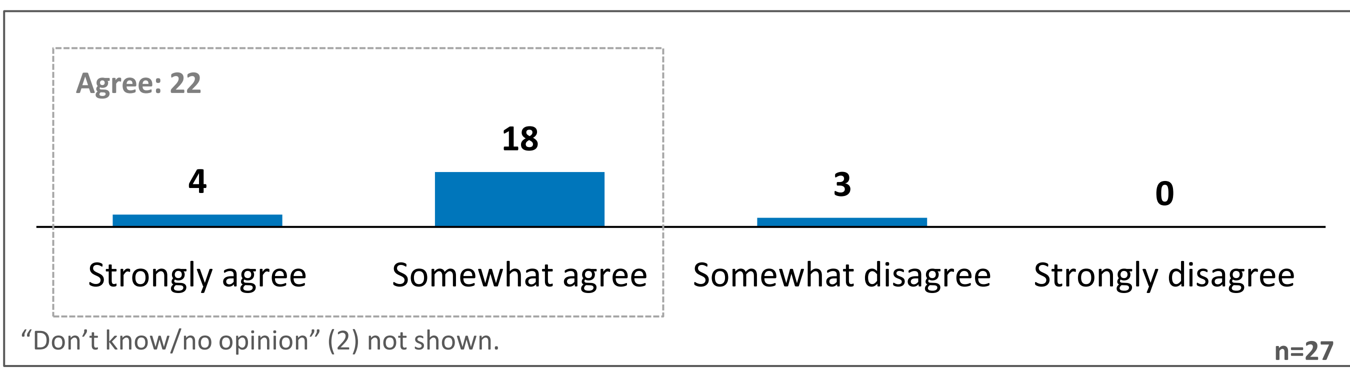
To what extent do you agree or disagree with the following statements?

Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



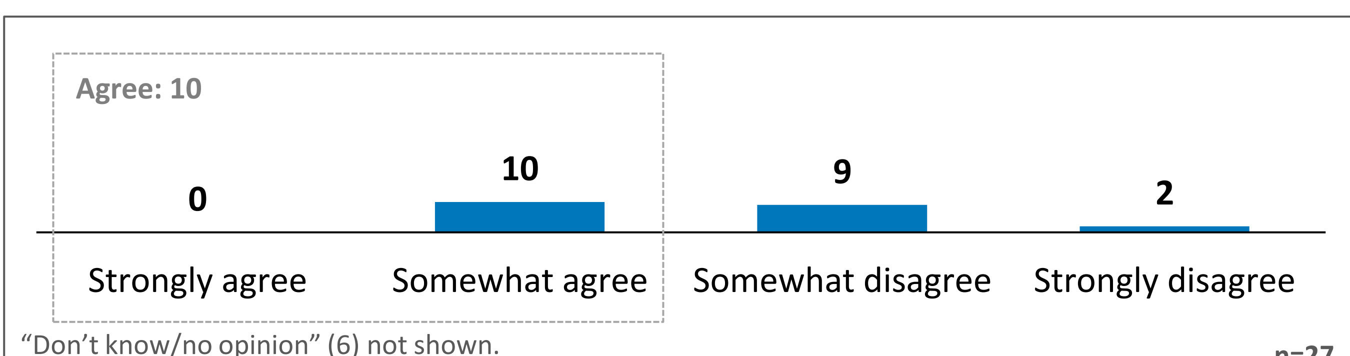
"Don't know/no opinion" (3) not shown.

Q Customers are well-served by the electricity system in Ontario.



"Don't know/no opinion" (2) not shown.

Q Customers are protected with respect to the price we pay for electricity.



"Don't know/no opinion" (6) not shown.

Online Survey

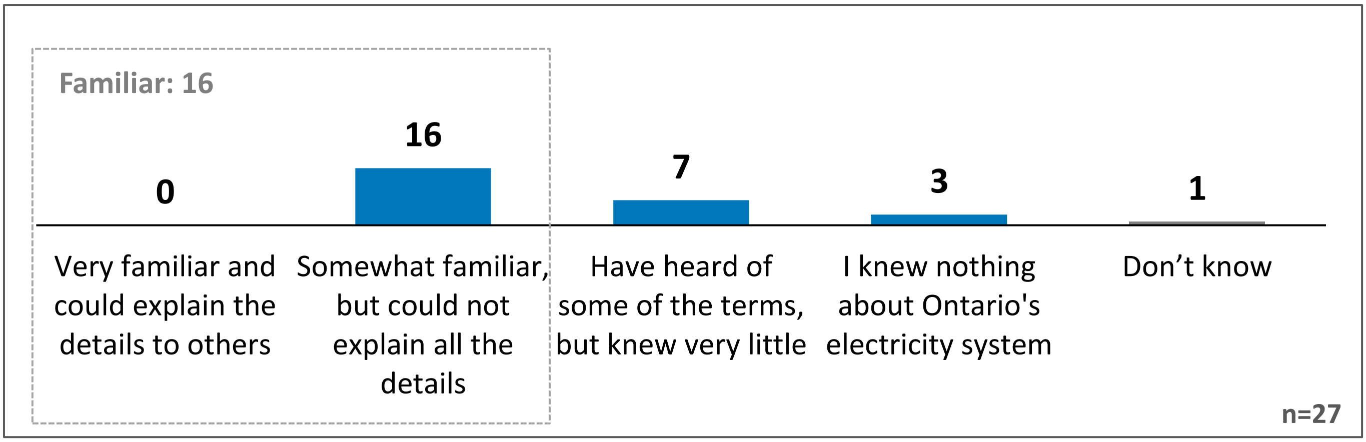
Familiarity with Ontario's Electricity System

Commercial & Industrial

As you may know, Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province
- **Local distribution networks** take the electricity from provincial transmission lines and bring it to your home through a network of wires, poles and other equipment.

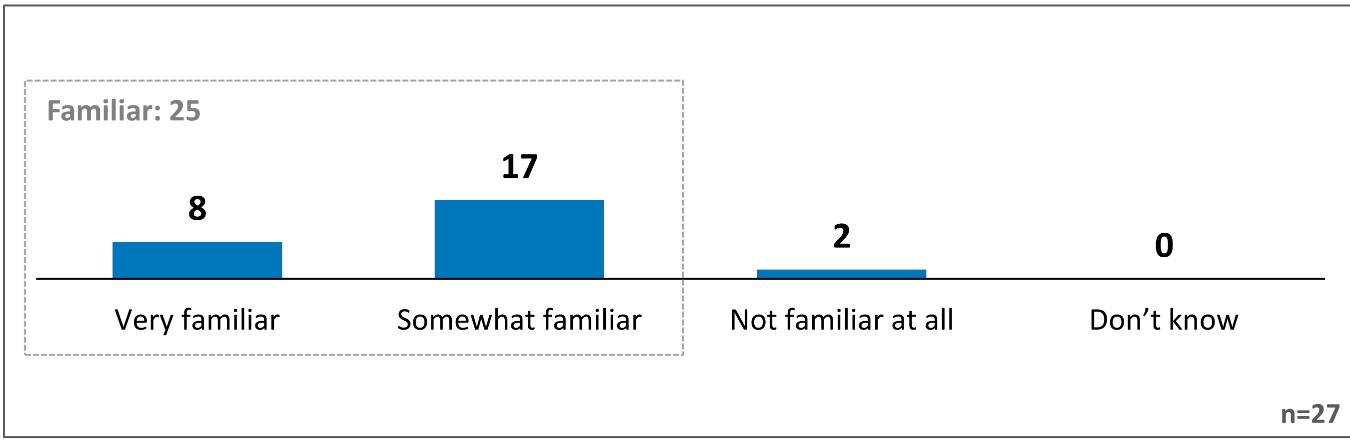
Q Before this survey, how familiar were you with the various parts of the electricity system and how they work together?



Online Survey
Familiarity with Entegrus

Entegrus manages all aspects of the electricity distribution business throughout 17 communities in Southwestern Ontario. This is the network that takes the electricity from high-voltage transmission towers and brings it to your home or business through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with **Entegrus**, which operates the electricity distribution system in your community?

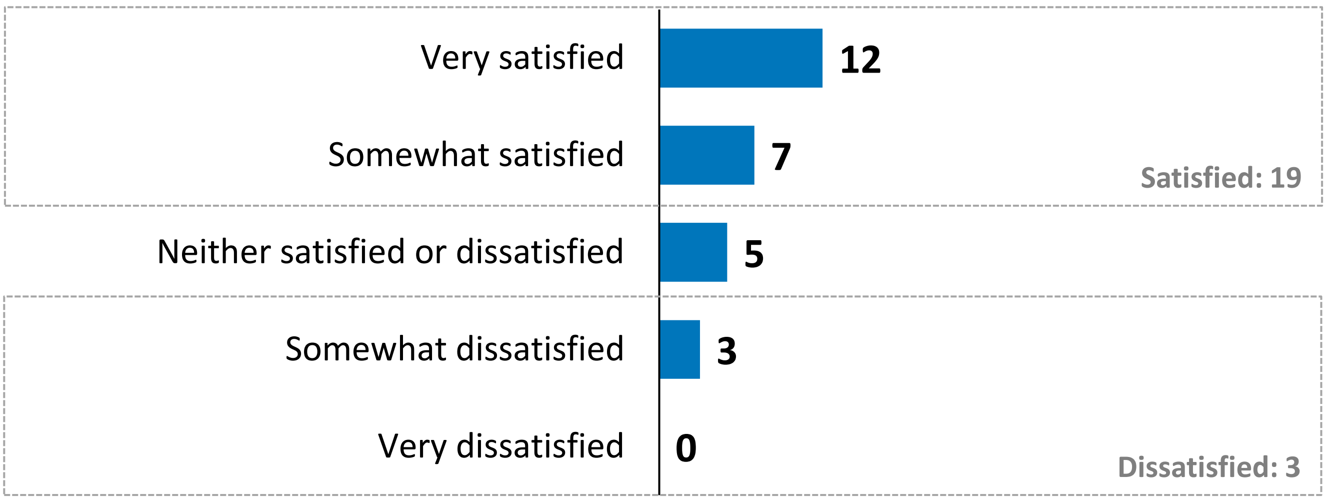


Online Survey

Overall Satisfaction with Entegrus

Commercial & Industrial

Q Thinking specifically about the services provided to you and your organization by **Entegrus**, overall, how satisfied or dissatisfied are you with the services that you receive?



"Don't know" (0) not shown.

n=27

Online Survey

How Entegrus can improve its services

Commercial & Industrial

Q Is there anything in particular you would like **Entegrus** to do to improve its services to you?

Response (n=18 'Don't know')
"Accessing multiple accounts on the website and return of deposits without having to send a letter of request after the 5-year mark. Should just be returned."
"Be more approachable and meeting to discuss projects that are in the development stage."
"Better rates."
"Better relay outage timelines to businesses."
"Bring the prices down ;)"
"Nothing comes to mind."
"Overall, they have been helpful."
"We have many brown outs or hydro outages each year. We have had to send employees home due to no power at the plant."

Note: Verbatims are shown due to the small sample size.

Online Survey

Bill Remittance Familiarity

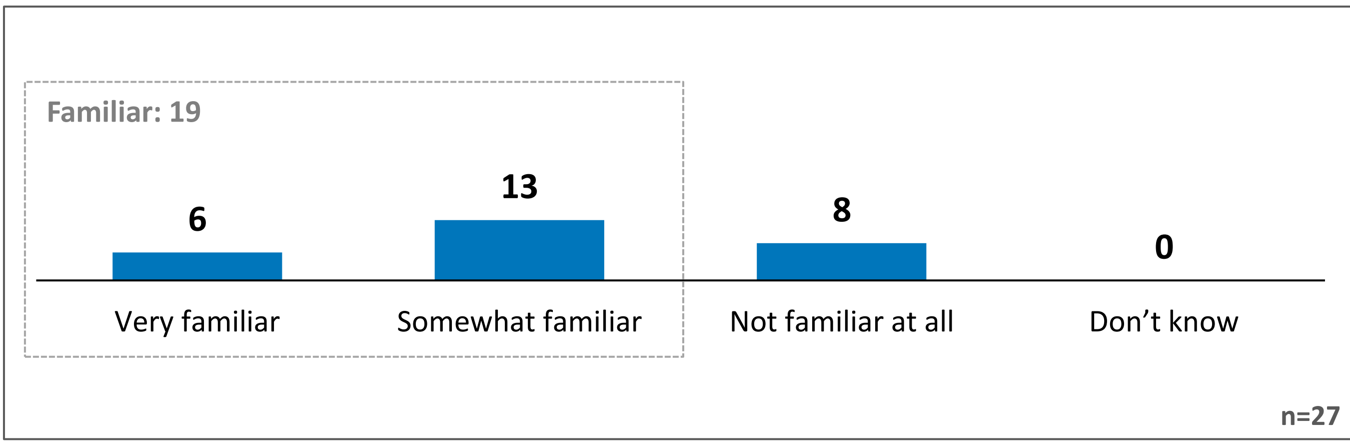
While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – **Entegrus** retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.

Distribution makes up about **8%** of the typical Commercial & Industrial/Large Use customer's bill.

The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

Q

Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Entegrus**?



INNOVATIVE
RESEARCH GROUP

Commercial & Industrial/Large Use Customers

Priorities & Preferences

Online Survey

Importance of Customer Priorities

Now, let's talk about our second topic – outcomes.

Everyday **Entegrus** interacts with hundreds of its customers through multiple channels and touchpoints, including surveys, the call centre and social media.

Through these ongoing interactions with customers, a number of company goals have been identified as priorities for **Entegrus**.

Shortened General Outcomes Priorities Response Labels	Full General Outcomes Priorities Response Labels
Delivering electricity at reasonable distribution rates	Delivering electricity at reasonable distribution rates
Ensuring reliable electrical service	Ensuring reliable electrical service
Investing in technology to withstand adverse weather	Investing in new technology that could lead to benefits such as better withstanding the impacts of adverse weather
Replacing aging infrastructure	Replacing aging infrastructure that is beyond its useful life
Quality customer service and communications	Providing quality customer service and enhanced communications
Helping customers with conservation and usage	Helping customers with conservation and changing their electricity usage
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure
Expanding grid to reduce impact on climate change	Expanding the electricity grid so that customers can reduce their impact on climate change by using electricity to replace fossil fuels (e.g., replacing gas-powered vehicles with electric vehicles or natural gas heating with heat pumps)
Enabling customers to access new electricity services	Enabling customers to access new electricity services (e.g., electricity storage, power walls and distributed generation, such as solar panels)

Online Survey

Importance of Customer Priorities

Commercial & Industrial

Q Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Entegrus** priorities to you as a customer?

Delivering electricity at reasonable distribution rates

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	0	0	0	0	0	0	0	1	1	2	21	2	Extremely important

Ensuring reliable electrical service

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	0	0	0	0	0	0	1	0	3	2	19	2	Extremely important

Investing in technology to withstand adverse weather

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	0	0	0	0	0	3	3	2	4	6	8	1	Extremely important

Replacing aging infrastructure

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	0	0	0	0	0	1	0	3	6	8	7	2	Extremely important

Quality customer service and communications

	0	1	2	3	4	5	6	7	8	9	10	Don't know	
Not at all important	0	0	0	0	0	2	1	2	7	6	8	1	Extremely important

Note: Priority labels have been shortened for brevity. See slide 106 for full label text.
Mean is not shown due to the small sample size.

Online Survey

Importance of Customer Priorities (Cont'd)

Commercial & Industrial

Q Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Entegrus** priorities to you as a customer?

Helping customers with conservation and usage

Not at all important — Extremely important

0	1	2	3	4	5	6	7	8	9	10	Don't know
0	0	0	0	0	3	3	5	4	6	5	1

Ensuring the safety of electricity infrastructure

Not at all important — Extremely important

0	1	2	3	4	5	6	7	8	9	10	Don't know
0	0	0	0	0	0	0	0	6	3	16	2

Expanding grid to reduce impact on climate change

Not at all important — Extremely important

0	1	2	3	4	5	6	7	8	9	10	Don't know
3	2	1	2	2	0	2	3	3	4	4	1

Enabling customers to access new electricity services

Not at all important — Extremely important

0	1	2	3	4	5	6	7	8	9	10	Don't know
1	1	0	3	0	3	3	3	4	3	5	1

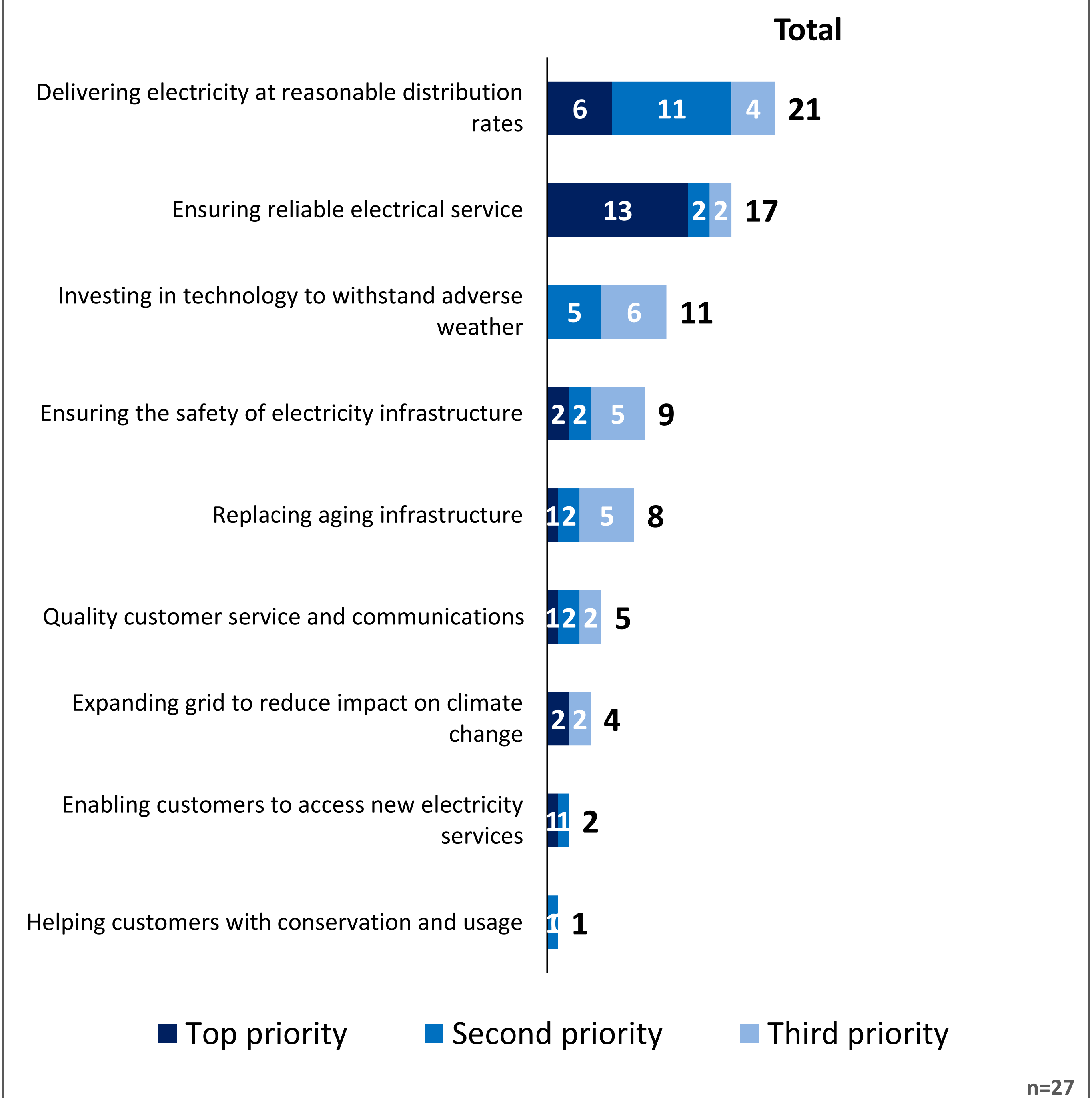
Note: Priority labels have been shortened for brevity. See slide 106 for full label text.
Mean is not shown due to the small sample size.

Online Survey

Ranking Customer Priorities

Commercial & Industrial

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Entegrus** should focus on? And what do you consider the third most important priority?



Note: Priority labels have been shortened for brevity. See slide 106 for full label text. "Don't know" is not shown.

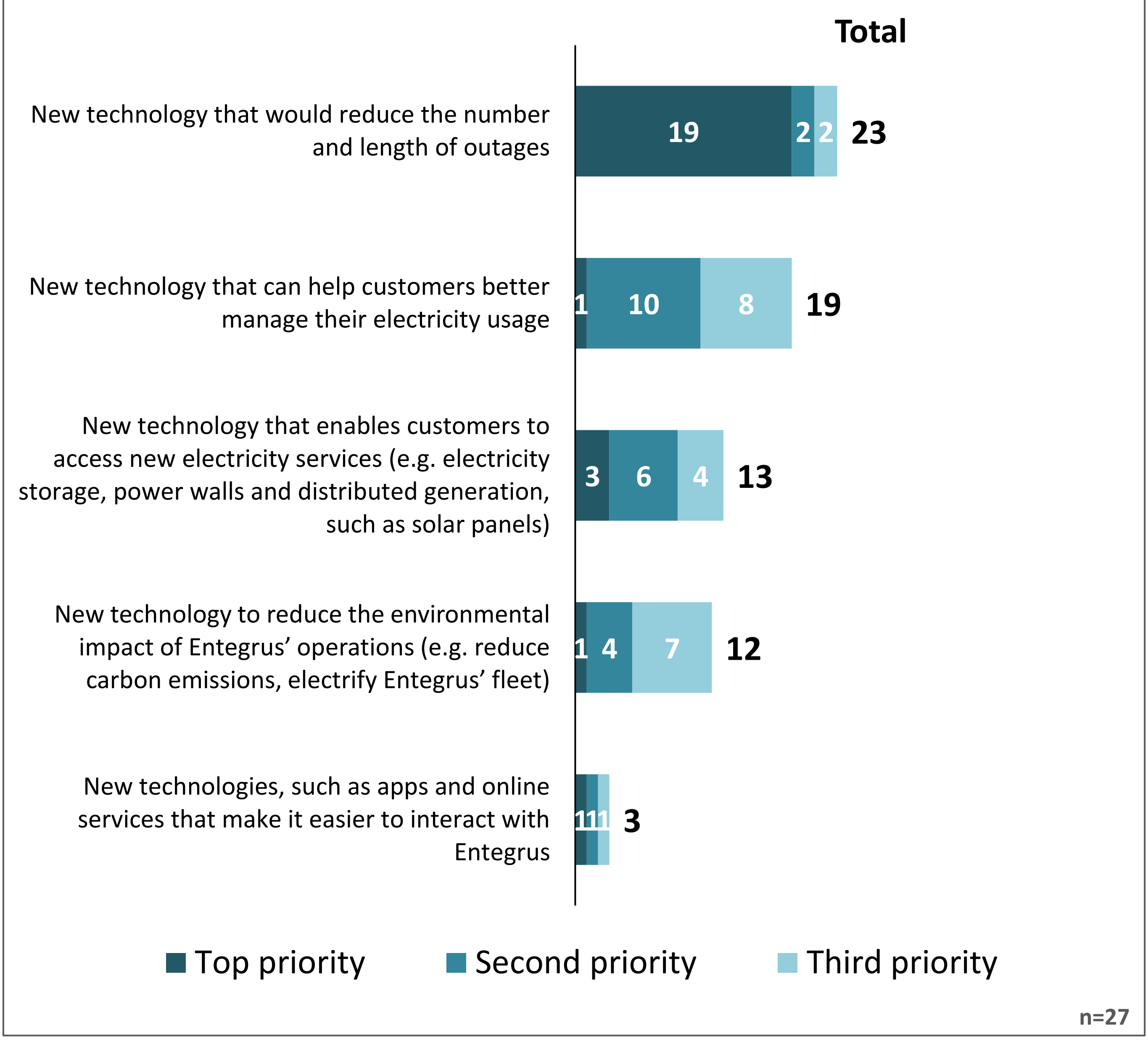
Online Survey

Ranking Investments in New Technology

Commercial & Industrial

Investments in new technology can help **Entegrus** address a range of issues. These include reliability, efficiency, customer service, **Entegrus'** impact on the environment, new service offerings and tools to manage electricity usage.

Q Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Entegrus** should focus on? And what do you consider the third most important priority?



Note: "Don't know" not shown.

Online Survey

Additional Priority Areas

Commercial & Industrial

Q Can you think of any other important priorities that **Entegrus** should be focusing on?

Response
"Controlling costs to large scale developments for developers and looking into cost sharing for these projects."
"Not at this time."

Note: Verbatims are shown due to the small sample size.

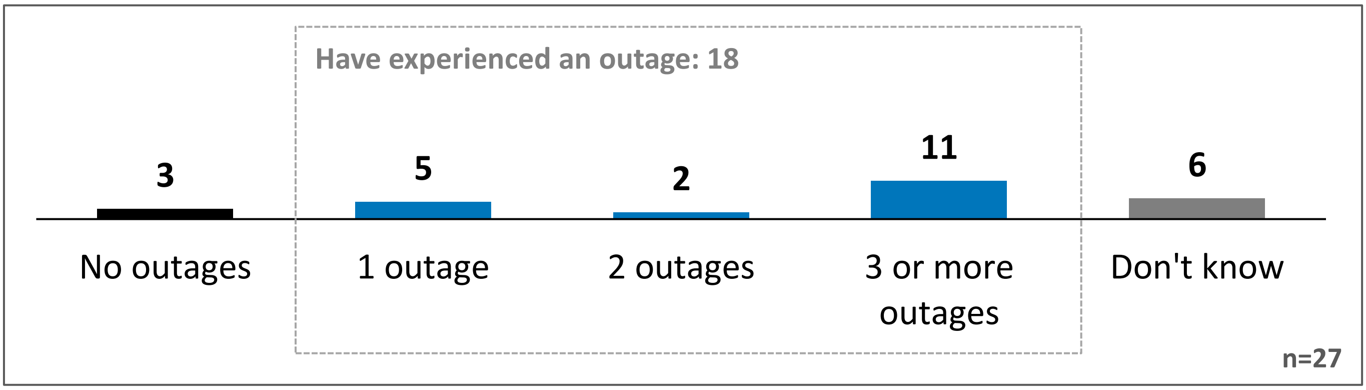
Online Survey
Reliability Experience

Commercial & Industrial

Now, let's talk about the reliability of electricity service your organization receives.

Q

Have you experienced any power outages at **your business in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?

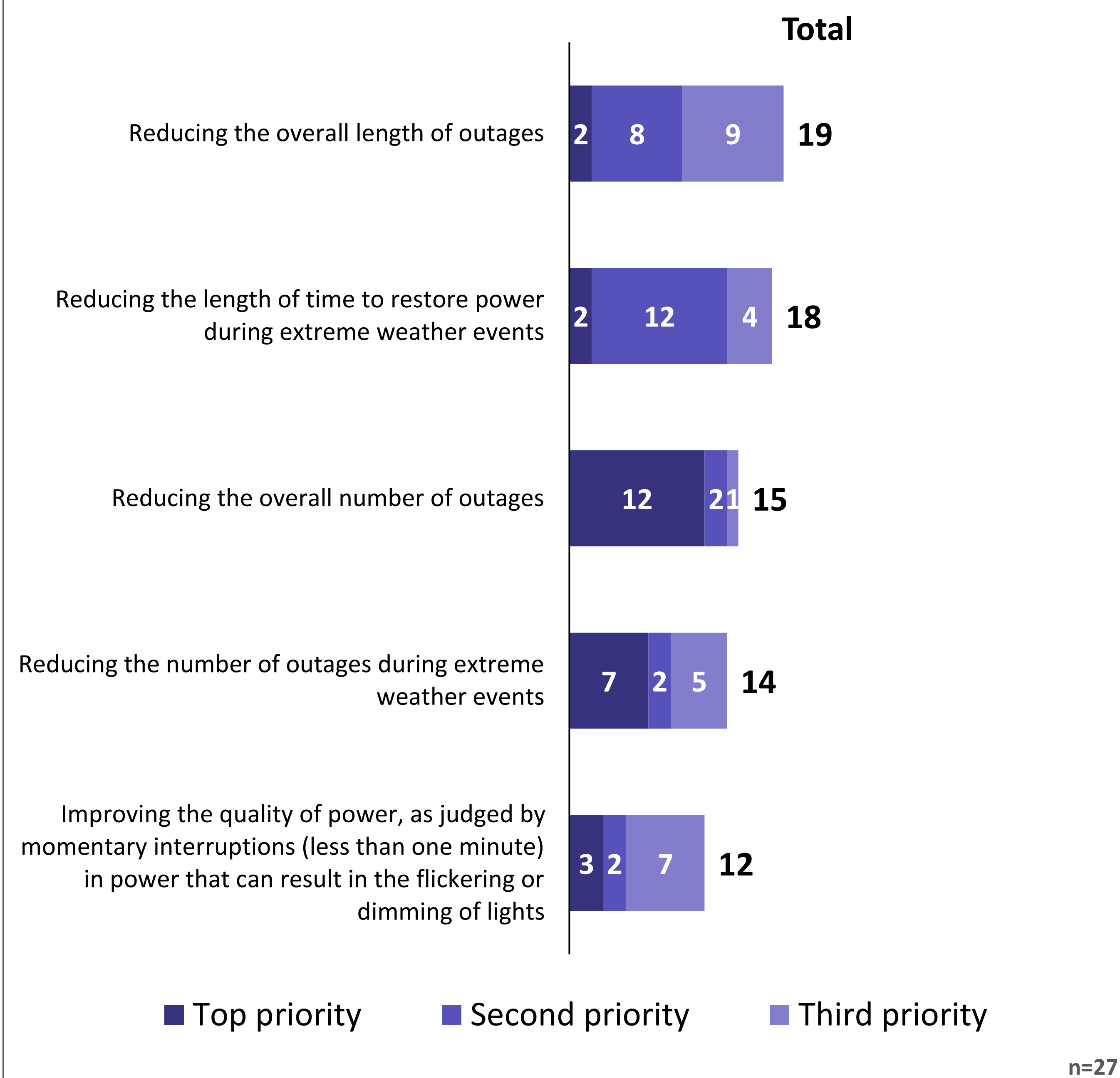


Online Survey

Ranking Reliability Preferences

Commercial & Industrial

Q When it comes to reliability, there are a number of areas that **Entegrus** can focus on. Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Entegrus** should focus on? And what do you consider the third most important priority?



Note: "Don't know" not shown.

INNOVATIVE
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Commercial & Industrial/Large Use Customers

Investment Trade-Offs

Online Survey

Investment Trade-Offs – System Renewal

Commercial & Industrial

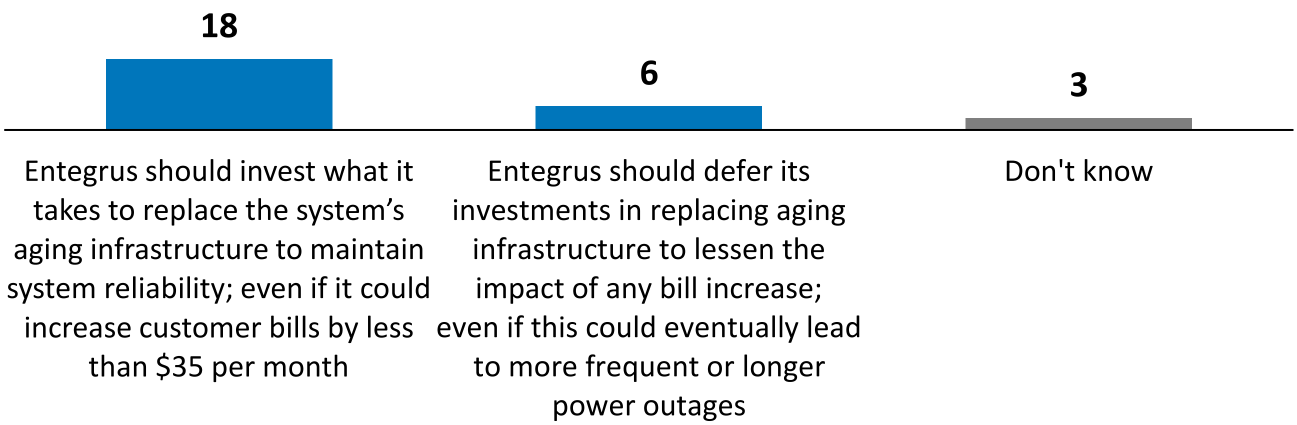
Now let's turn to our third topic – investment trade-offs.

Entegrus is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to know your preferences when it comes to finding the right balance between costs and other outcomes.

There are three investment categories that we would like to discuss.

The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

Q Regarding investments in aging infrastructure, which of the following statements best represents your point of view?



n=27

Online Survey

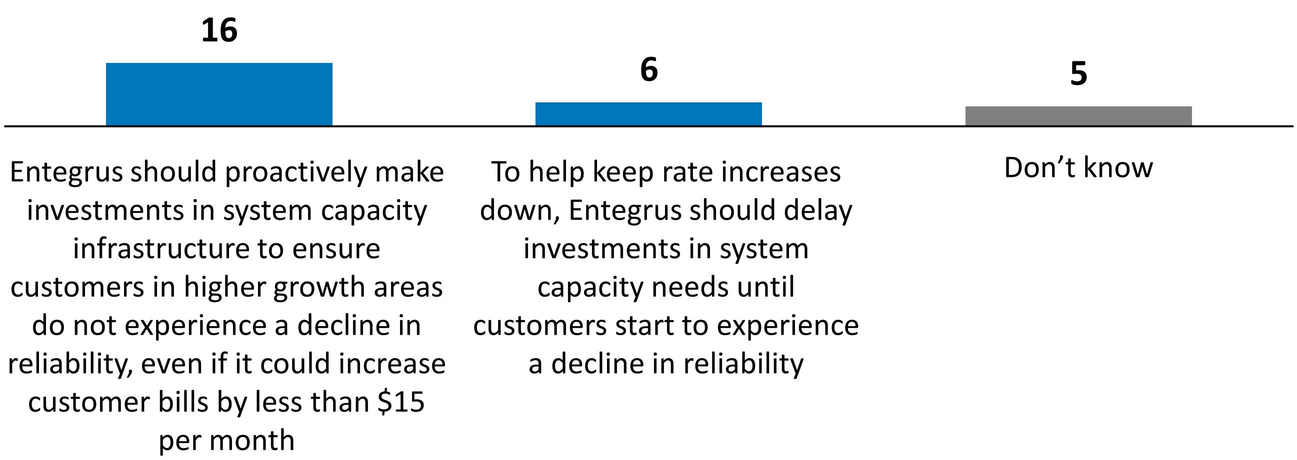
Investment Trade-Offs – System Service

Commercial & Industrial

The second investment category focuses on growth and greater demand for electricity in various parts of **Entegrus'** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

Q With this in mind, which of the following statements best represents your point of view?



n=27

Online Survey

Investment Trade-Offs – Grid Modernization

Commercial & Industrial

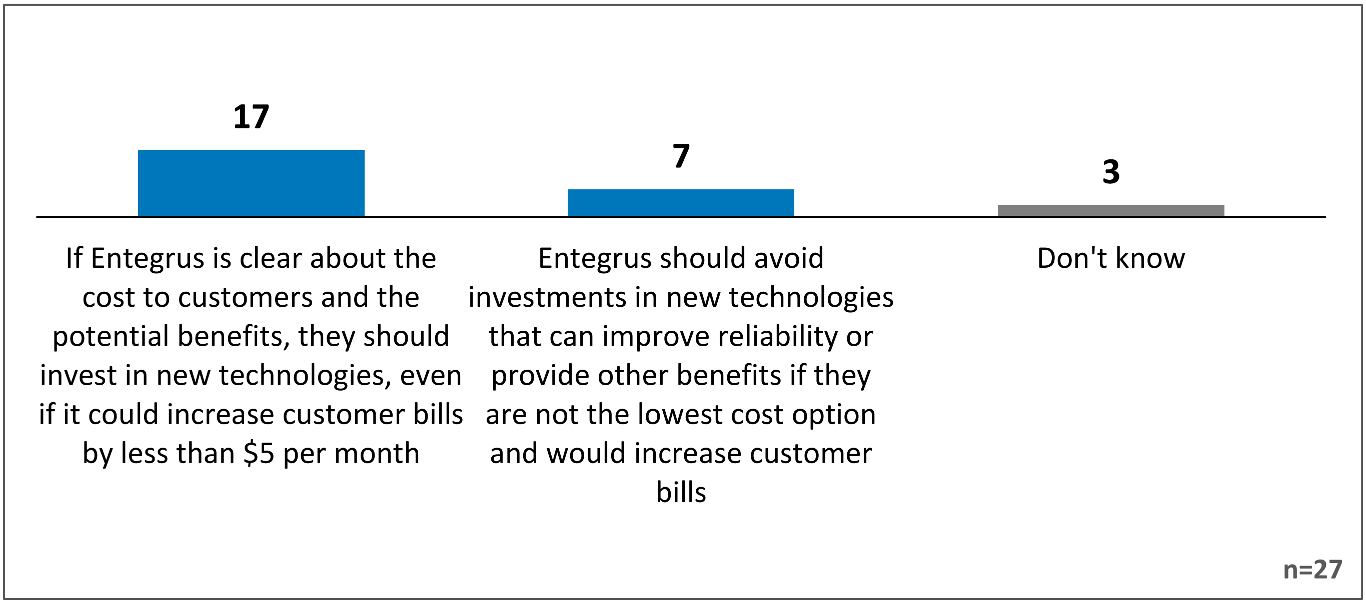
Entegrus can invest in technology that can lead to a wide range of benefits including reliability, efficiency, customer service, and reducing environmental impacts.

Entegrus generally invests in technology when it provides equal or improved service at the least cost.

However, there are times when **Entegrus** identifies *new* technology that can improve reliability or provide other benefits, but it will cost customers more.

For instance, advanced customer meters that can measure when different appliances or equipment are running, allowing **Entegrus** to provide customers with better advice on how to reduce their energy consumption and costs.

Q Regarding these types of investments, which of the following best represents your view?



Commercial & Industrial/Large Use Customers

Specific Investments

Online Survey

Specific Investments – System Monitoring

Now let's turn to our final topic – specific investment decisions that Entegrus would like your feedback on.

The first potential investment is in emerging technology to better monitor **Entegrus'** distribution system.

Specifically, **Entegrus** serves 17 communities and has thousands of trees across its service territory and in proximity to its lines.

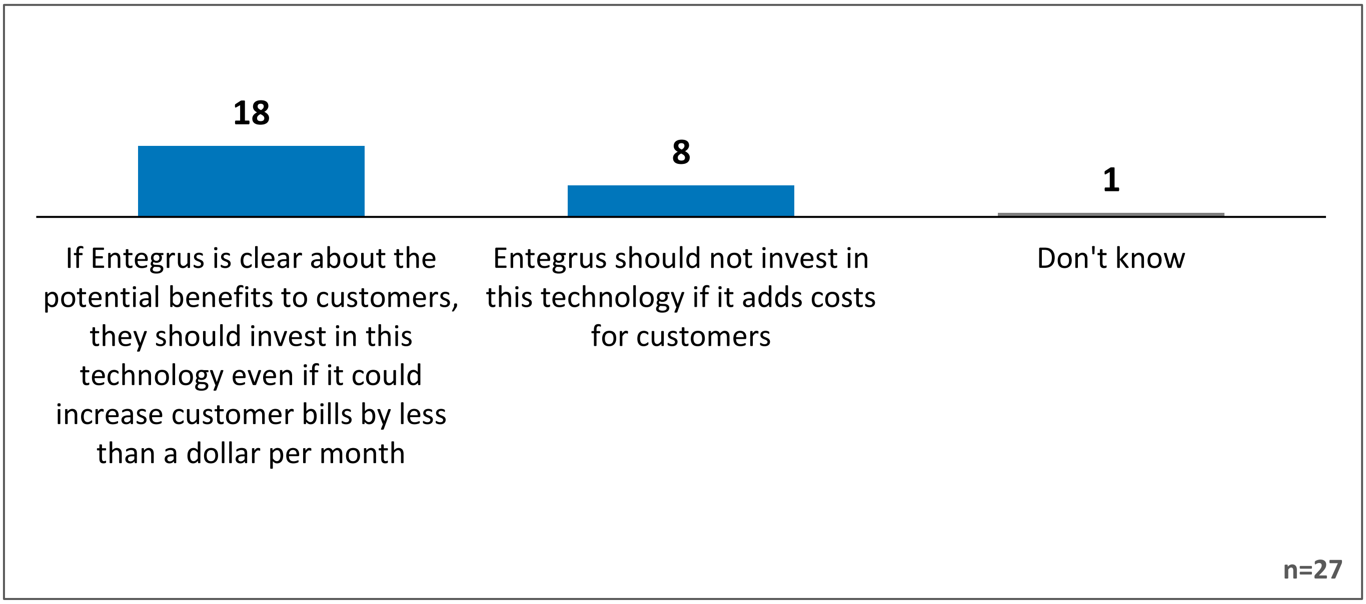
On a regular basis, **Entegrus** must ensure those trees remain a safe distance from electrical equipment like poles and wires. On a multi-year cycle, Entegrus goes community-by-community to trim trees and other vegetation. In a typical year, outages due to tree contacts account for approximately 7-19% of all customer outages.

New technology is emerging that would allow **Entegrus** to become more targeted in the trees that are selected for maintenance. This technology uses high resolution satellite imagery to build a 3D model of **Entegrus**' service territory and lines, allowing detailed measurements within centimeters.

This technology will allow precise planning for arborists that minimizes the magnitude of trimming required, but it would cost more upfront to implement.

While the benefits wouldn't be immediate, in the long-run, **Entegrus** believes that it could result in reducing the number of outages caused by tree contacts.

Q Regarding investments in technology to change the way **Entegrus** monitors and maintains trees and vegetation, which of the following best represents your view?



Online Survey

Specific Investments – Demand Response

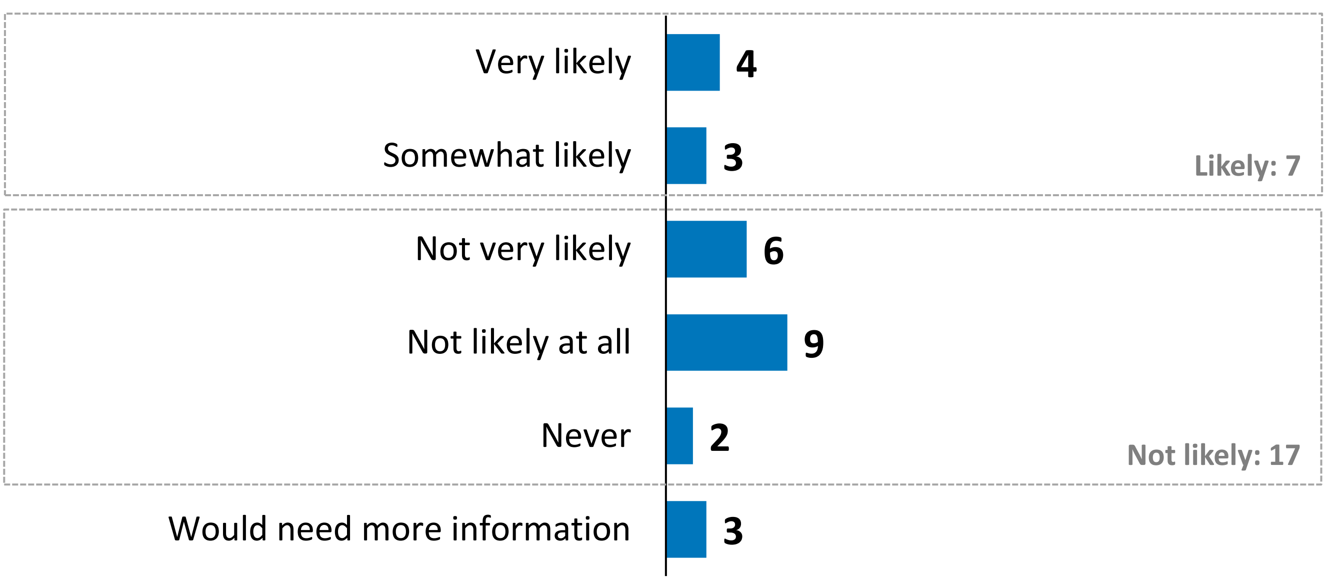
The second investment is in response to growing demand.

Electricity demand is on the rise across **Entegrus**' service territory. This increasing demand, resulting from industrial and residential growth, as well as the changing ways we use electricity, will require electricity companies like **Entegrus** to make significant investments in the grid.

One way to delay the need for system capacity upgrades is to offer incentives to customers for reducing or shifting their electricity consumption at times of peak demand.

For example, this could include reducing the speed or power of equipment or limiting the use of large equipment at times of peak demand.

Q If **Entegrus** were to introduce an **opt-in program** that offered incentives for reducing or shifting electricity consumption at times of peak demand, how likely would you be to enrol?



"Don't know" (0) not shown.

n=27

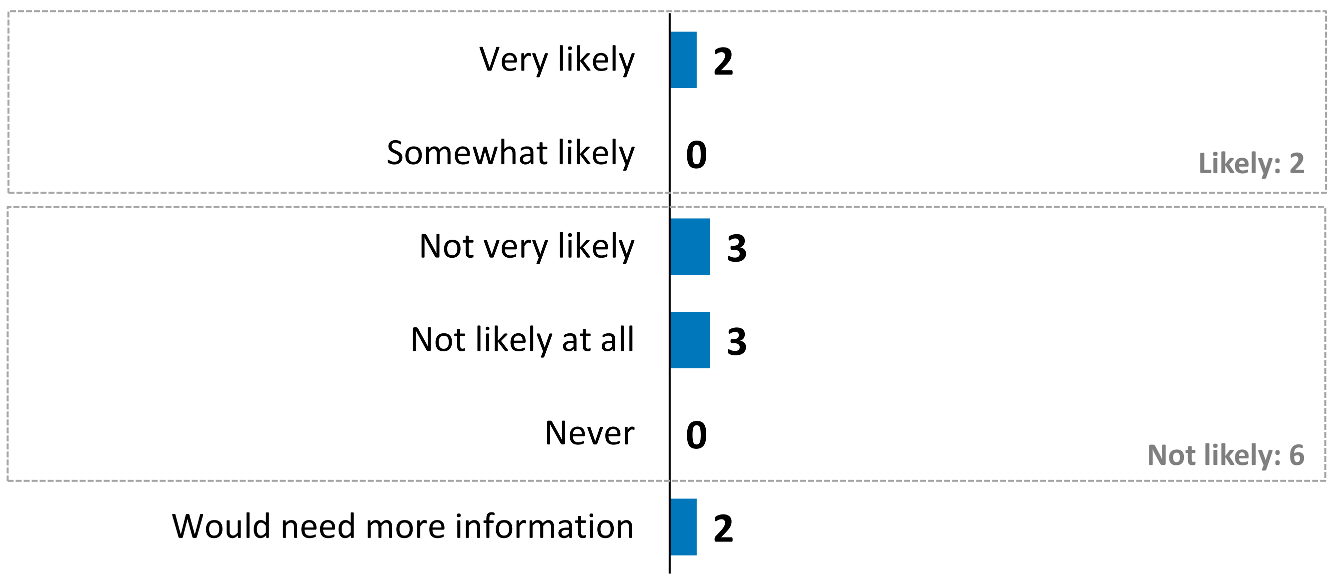
Online Survey

Specific Investments – Demand Response

Q

If Entegrus were to offer you **$50 per average kilowatt demand reduction during peak events/$75 per average kilowatt demand reduction during peak events** in a program like this, how likely would you be to enrol?

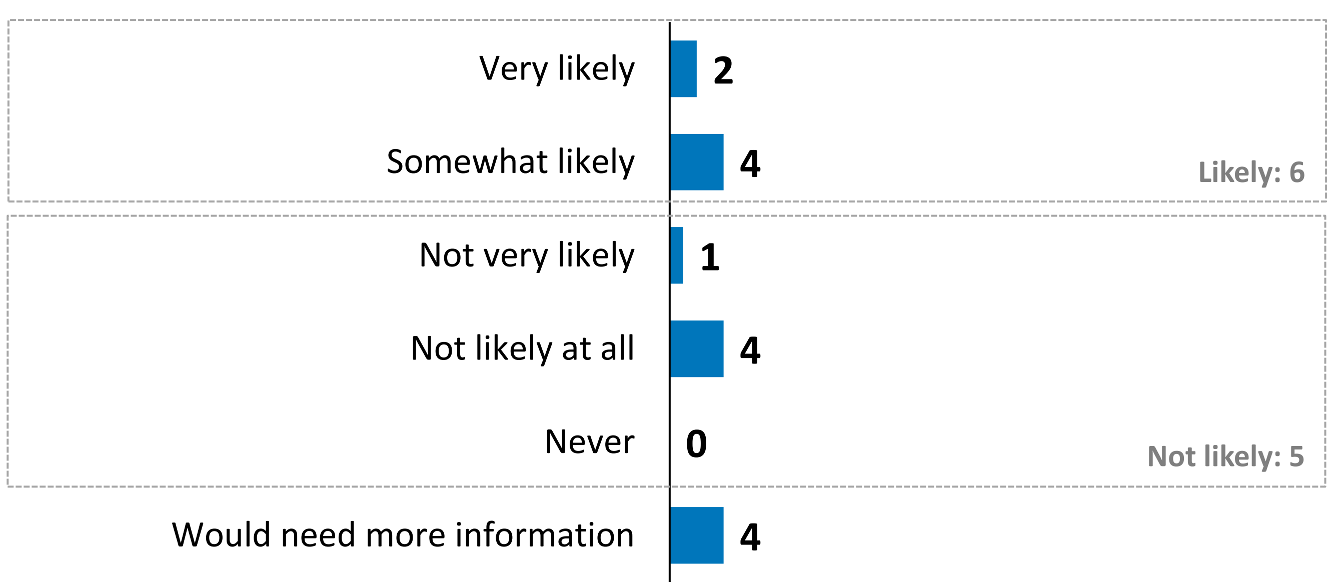
$50 per average kilowatt demand reduction during peak events



"Don't know" (1) not shown.

n=11

$75 per average kilowatt demand reduction during peak events



"Don't know" (1) not shown.

n=16

Online Survey

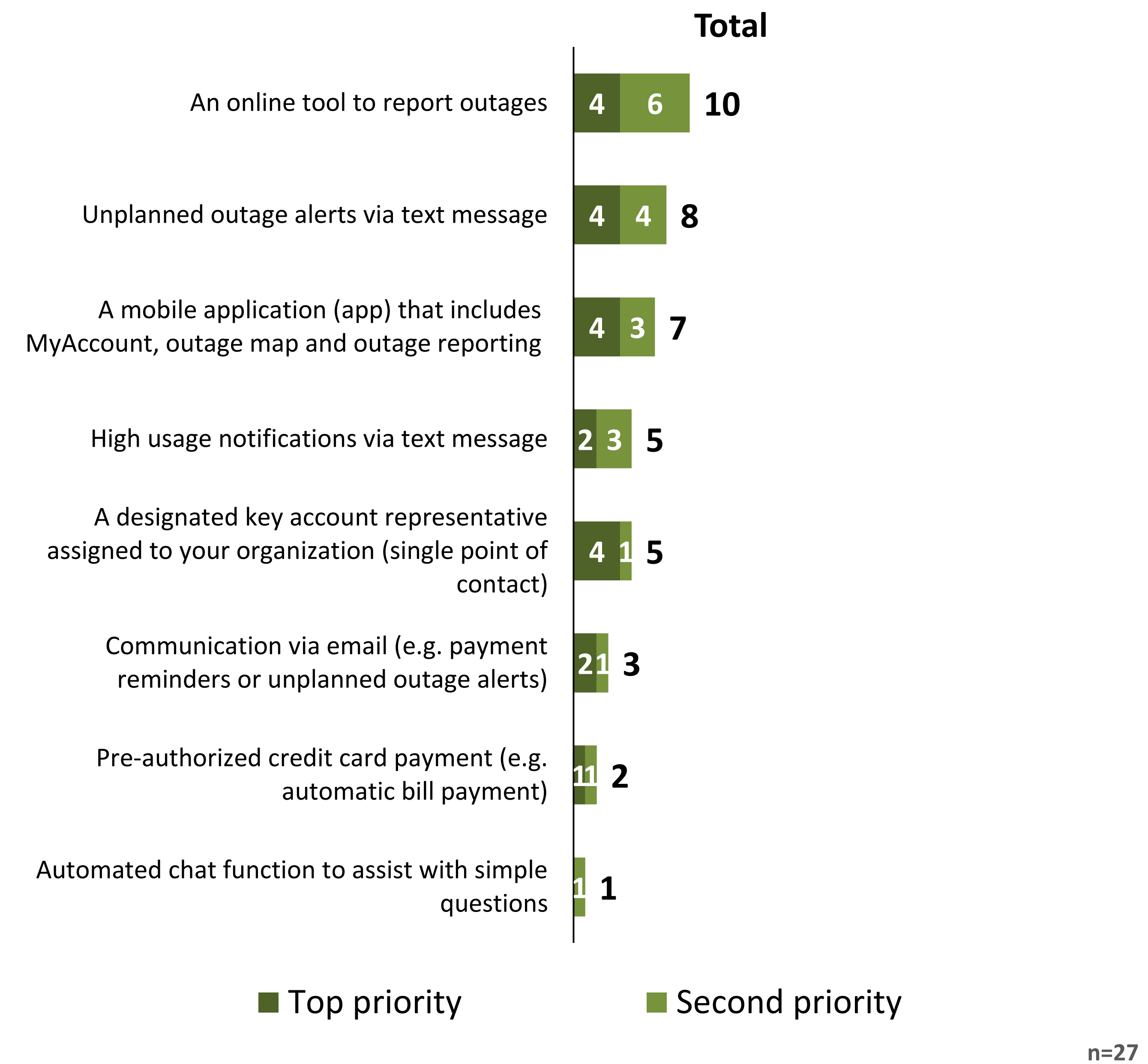
Commercial & Industrial

Specific Investments – Expanded Customer Service Offerings

The final series of investments are related to potential expanded customer service offerings.

There are several ways that **Entegrus** can expand its service offerings to customers. Of course, each of these expanded offerings come at a cost to customers.

Q Which of the following expanded customer service offerings would you be **most interested** in? And which would you be the next most interested in?



Note: "Don't know" and "None of the above" are not shown.

INNOVATIVE
RESEARCH GROUP

Commercial & Industrial/Large Use Customers

Future Electricity Needs

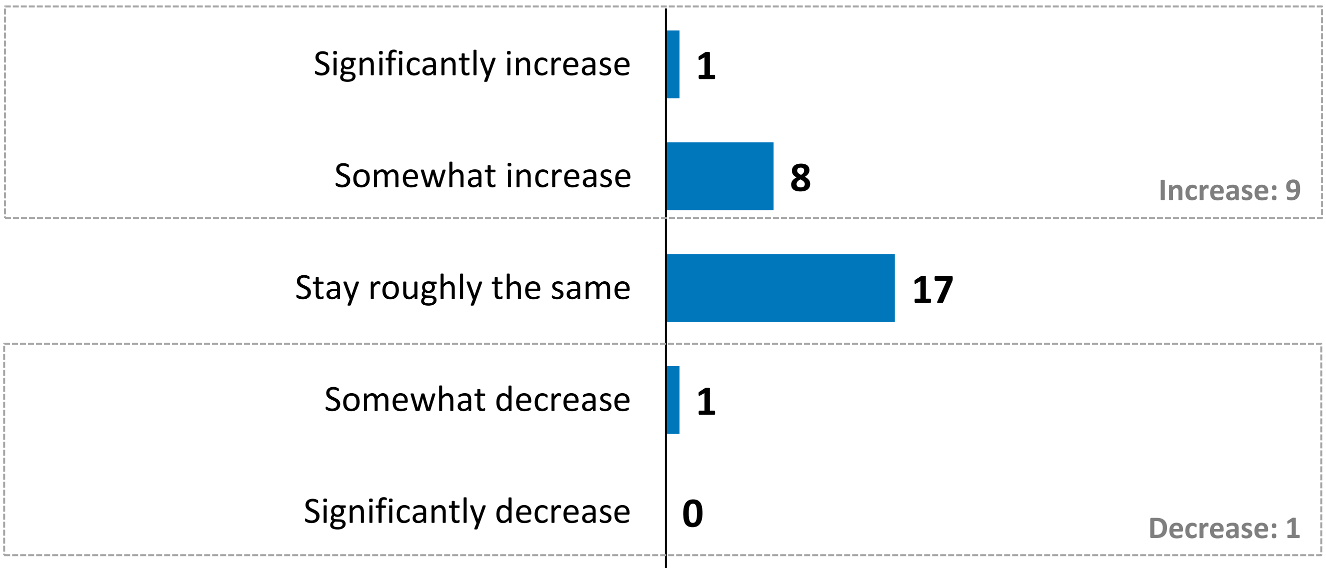
Online Survey

Anticipated Organization's Electricity Usage

Commercial & Industrial

Entegrus is interested in understanding how your organization is planning for the future.

Q In the next five years, do you anticipate your organization's electricity usage will increase, decrease, or stay roughly the same?



"Don't know" (0) not shown.

n=27

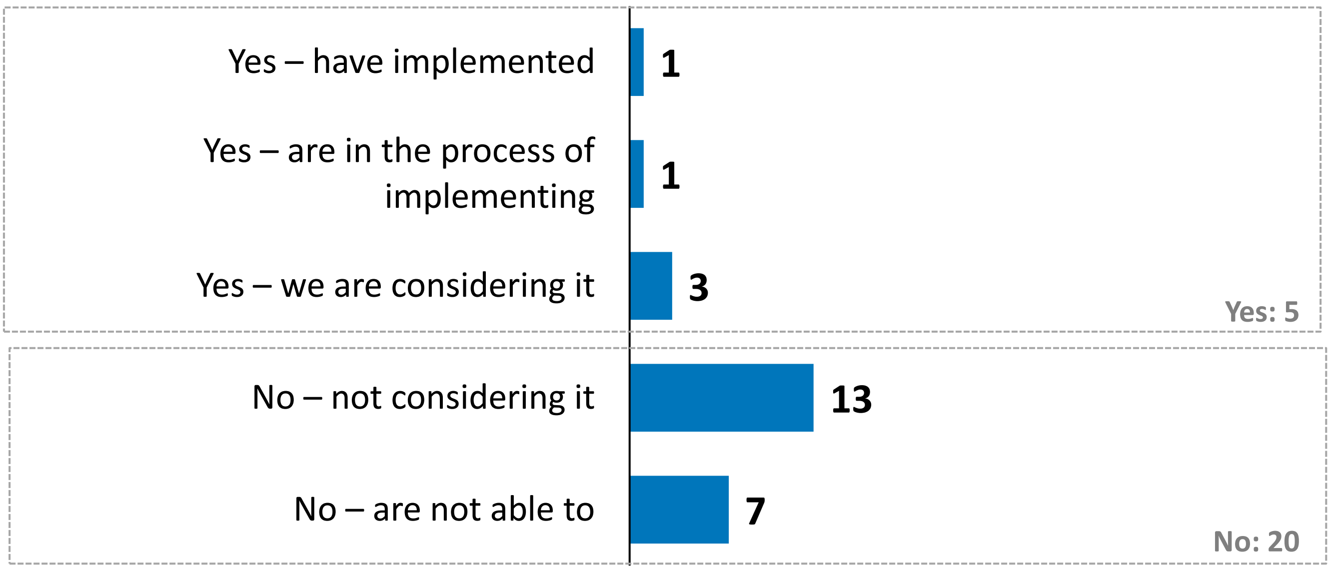
Online Survey

Implemented/Considering – Electric Fleet

Commercial & Industrial

Q Has your organization implemented, or are you considering implementing, any of the following?

Transitioning to an electric fleet



"Don't know" (2) not shown.

n=27

Responses from those who say "No – are not able to"
Verbatim
"Cannot wait for charging. Need instant refueling."
"Don't think electric vehicle are going to last."
"Infrastructure upgrades to accommodate higher usage is cost prohibitive."
"Larger Equipment and some smaller vehicles. Would look at hybrid solutions for the smaller stuff."
"We are a church and do not have a fleet or own any vehicles."
"We don't have a fleet."
"We use heavy duty commercial trucks - electric versions not yet available."

Note: Verbatims are shown due to the small sample size.

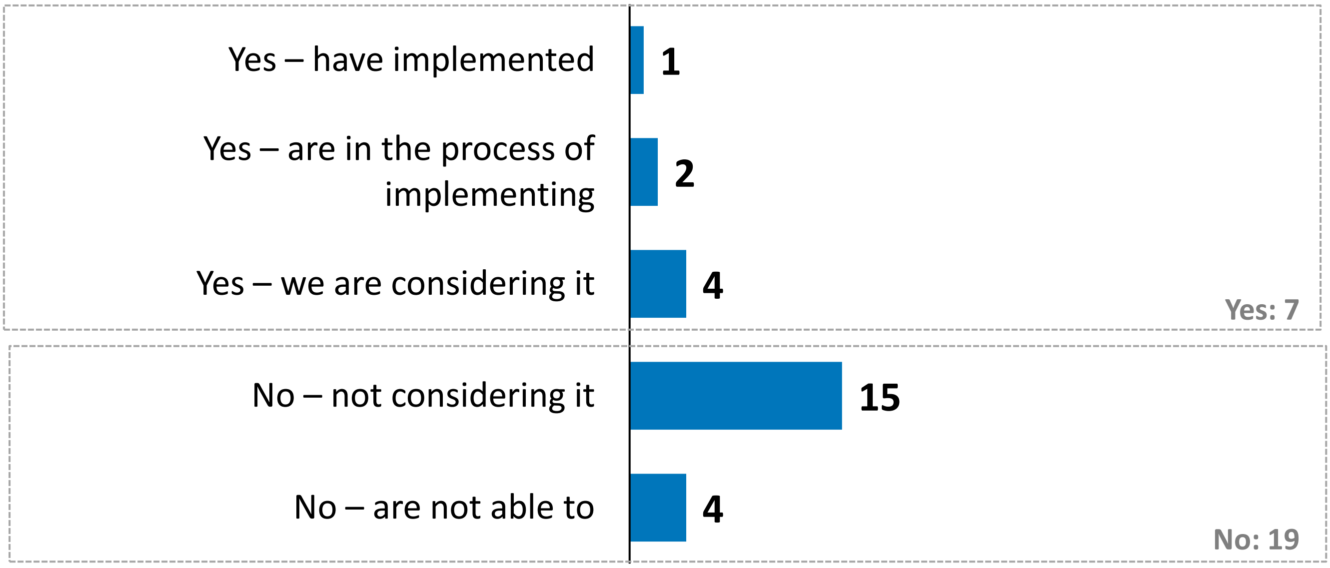
Online Survey

Implemented/Considering – EV Charing Equipment

Commercial & Industrial

Q Has your organization implemented, or are you considering implementing, any of the following?

Investments in electric vehicle charging equipment



"Don't know" (1) not shown.

n=27

Responses from those who say "No – are not able to"
Verbatim
"Don't think electric vehicle are going to last."
"Infrastructure upgrades to accommodate higher usage is cost prohibitive."
"Vandalism."
"We do not need or can afford to provide this service to the people who drive here."

Note: Verbatims are shown due to the small sample size.

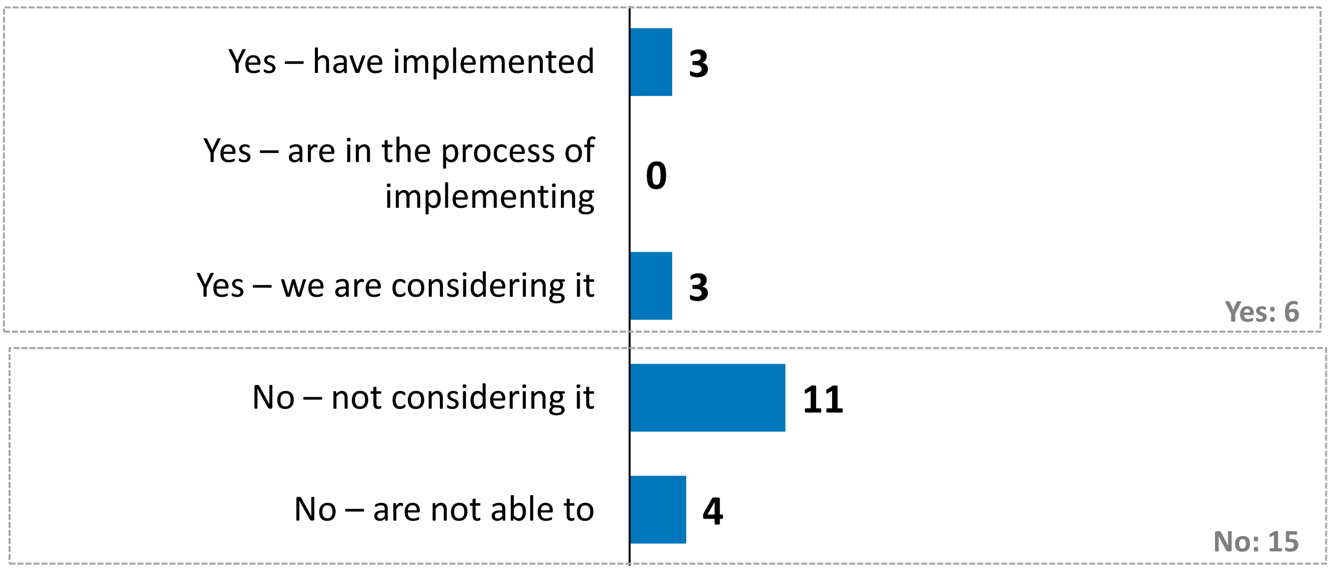
Online Survey

Commercial & Industrial

Implemented/Considering – Renewables Energy Sources

Q Has your organization implemented, or are you considering implementing, any of the following?

Investments in renewable energy sources (solar, wind, etc.)



"Don't know" (6) not shown.

n=27

Responses from those who say "No – are not able to"
Verbatim
"Cannot support the weight."
"Cost."
"Infrastructure upgrades to accommodate higher usage is cost prohibitive."
"We have other priorities."

Note: Verbatims are shown due to the small sample size.

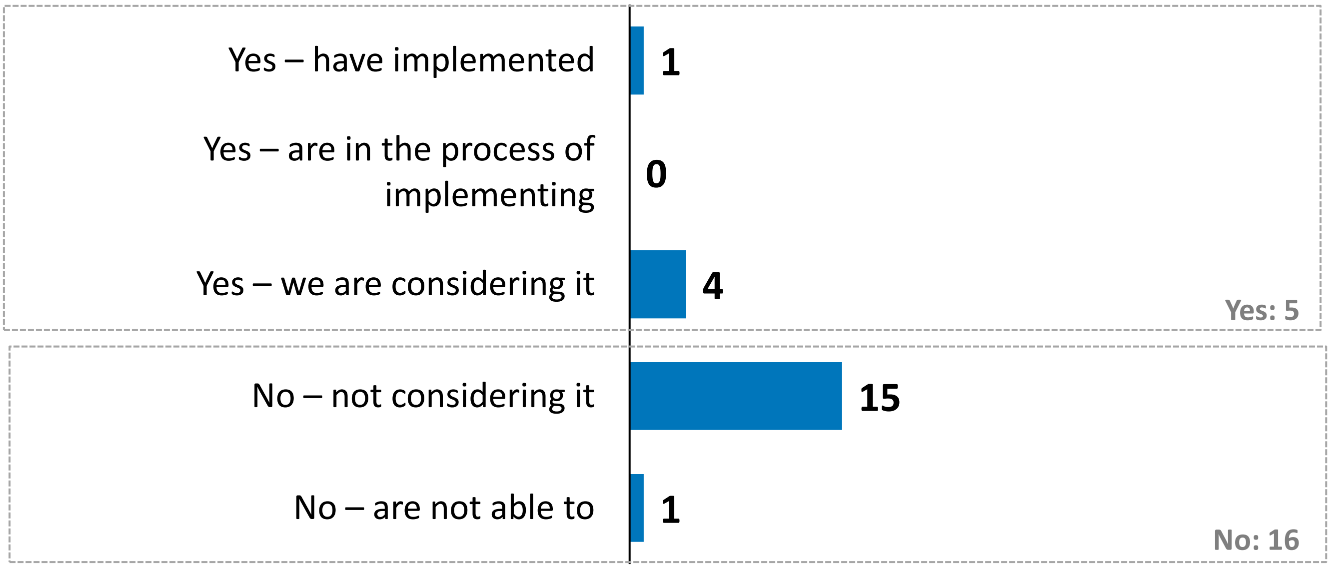
Online Survey

Implemented/Considering – Gas to Electricity

Commercial & Industrial

Q Has your organization implemented, or are you considering implementing, any of the following?

Transitioning heating or other equipment from natural gas to electricity (i.e., from a gas furnace to an electric heat pump)



"Don't know" (6) not shown.

n=27

Responses from those who say "No – are not able to"

Verbatim
"Upgrades to all the equipment would be hundreds of thousands of dollars, and the infrastructure upgrades to accommodate the higher power usage are cost prohibitive. Entegrus infrastructure grid is overtaxed now when people use AC. Your grid will not be able to handle everyone switching everything away from fossil fuels. You should have been saving your profits all along to reinvest in upgrades to your infrastructure instead of proposing or demanding higher rates for you."

Note: Verbatims are shown due to the small sample size.

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Entegrus. The conclusions drawn and opinions expressed are those of the authors.

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Online Workbook

Phase II Customer Engagement

May 2025

Table of Contents

Phase II Online Workbook Report Overview

Introduction	3
Sample Validation	5
Summary Results	8

Residential Workbook Results

Methodology	11
Demographics	12
Detailed Results	15

Small Business Workbook Results

Methodology	73
Firmographics	74
Detailed Results	77

Commercial & Industrial Workbook Results

Methodology	126
Firmographics	127
Detailed Results	130

Introduction

Phase II Customer Engagement Survey

Entegrus 2026 Cost of Service Rate Application Customer Engagement (Phase II)

Innovative Research Group Inc. (INNOVATIVE) was engaged by Entegrus Powerlines Inc. to assist in meeting its customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors and Chapter 5 Filing Requirements. The information contained within this report is the result of a series of online workbook surveys conducted as part of Phase 2 of this customer engagement.

Setting the Context

Entegrus is in the process of finalizing its 2026 Cost of Service Rate Application. In order to ensure that Entegrus' plans are responsive to the needs and preferences of customers, a two-phased customer engagement program has been developed. **The results within this report reflect the second phase of this engagement.**

In Phase I, Entegrus and INNOVATIVE sought to develop a current understanding of customer needs and preferences, as well as gain some preliminary insights on some more specific investments that could be further explored in Phase II.

Phase II of this engagement focused on ensuring that the plans developed by Entegrus, with inputs from Phase I, were aligned with current customer expectations – including specific investments.

As in Phase I, a key principle of this phase used random-sampling research methods to ensure a representative sample of customers were engaged, ensuring the generalizability of the findings.

For residential and small business (GS<50kW) customers, responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. Due to the size of the rate class, Commercial and Industrial results were not weighted and should be interpreted as directional only.

INNOVATIVE RESEARCH GROUP

Introduction
Segmenting Customers

Customer Segmentation

In addition to segmenting customers based on where they reside or operate in Entegrus' service territory, it is important to be able to identify factors that may influence customer preferences and distinguish between what is within, and what is outside of Entegrus' influence or control.

Segmentation has been used throughout the residential and small business sections of this report to look beyond the topline numbers to analyze the results for key segments:

1. **Region:** Using customer data provided by Entegrus, we split customers into four regions for analysis; Chatham, St. Thomas, Strathroy, and the "rest" (i.e., outside of the other three regions).

2. **Bill Impact on Finances**: Segmentation that INNOVATIVE refers to as "Bill Impact on Finances" is provided. This segment is determined based on the extent to which customers agree with the following statement:

    a) <u>Residential</u>: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

    b) <u>Small Business</u>*: The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.*

3. **Vulnerable Consumers**: For residential customers, using a combination of household size and combined household income, the report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's *Ontario Electricity Support Program (OESP)* criteria.

4. **Consumption Quartiles**: For residential and small business customers, results are also shown by consumption quartiles, or otherwise, how much electricity the customer consumes in an average month (in KWh). This is used to ensure that no one customer consumption profile is over or underrepresented in the survey results.

Understanding Segmentation

Segmentation is an effective way of looking past the topline numbers and dig deeper into the needs and preferences of the customer segments above. For instance, while it is valuable to know that, overall, 80% of residential customers are satisfied with Entegrus, it is also important to understand whether satisfaction differs based on region or based on perceptions that may be outside of the utility's influence or control. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel about various issues.

Sample Validation

Email Coverage

Sample Validation

To ensure that customers reached by email are representative of the broader population of Entegrus customers, we use Entegrus' complete customer lists to compare known sample variables between those with an email address and the full population of customers.

This allows us to identify any systematic differences between those with an email on file and the full population of customers on known variables that may impact outcomes. All samples that are weighted include quotas by region and (collapsed) consumption quartile to ensure representativeness.

Overall Customer Email Coverage

The table below summarizes the email coverage of each rate class.

Rate Class	Total Records (Meters)	Unique customers*	Customers with an email	Email coverage (out of customers)
Residential	55,179 meters	51,004	32,898	**64.5%**
Small Business (GS<50)	5,745 meters	3,301	2,322	**70.3%**
C&I/Large Use (GS>50)	506 meters	317	276	**87.1%**

*Unique *customers* from the complete list of Entegrus' records (individual meters) are identified by cross-referencing available contact information to identify customers with multiple meters. Customers are assigned to their highest-order rate class in the following order (Large Use, Commercial & Industrial, Small Business (GS<50kW), Residential). For customers with multiple records within the same rate class, the record with the highest average monthly consumption is used for the purpose of assigning sample variables.

Sample Validation

Email Sample vs. Total Customer Accounts

Sample Validation

The information on this page and the one following compares the sample of each rate class with email addresses to the total customer accounts of that rate class across two known variables – distributions of (1) region and (2) average monthly consumption.

Legend: Difference*
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

(1) Regional Distribution by Rate Class

Communities are grouped into four unique regions within Entegrus' service territory.

Across rate classes, the distributions of region between the full population and email sample are similar (+/- 4%).

Rate Class	Region	Share of full population	Share of email sample	Difference
Residential	Chatham	31%	34%	**+3%**
	St. Thomas	31%	28%	**-2%**
	Strathroy	10%	10%	**0%**
	Rest	28%	28%	**0%**
Small Business (GS<50)	Chatham	28%	31%	**+3%**
	St. Thomas	31%	29%	**-2%**
	Strathroy	10%	9%	**0%**
	Rest	32%	31%	**-1%**
C&I/Large Use (GS>50)	Chatham	35%	36%	**+1%**
	St. Thomas	23%	22%	**-1%**
	Strathroy	12%	11%	**-1%**
	Rest	30%	31%	**+2%**

INNOVATIVE RESEARCH GROUP

Sample Validation

Email Sample vs. Total Customer Accounts Cont'd

(2) Distribution of Consumption Quartile by Rate Class

Across rate classes, the distributions of consumption quartile between the full population and email sample are similar (+/- 4%). Average monthly consumption and demand is slightly higher in the email sample compared to the full population across all rate classes.

This difference is accounted for in the survey results by setting quotas based on consumption quartile to ensure the survey results are representative of the Entegrus customer base.

Legend: Difference*
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

Rate Class	Consumption Quartile	Share of full population	Share of email sample	Difference
Residential	First	25%	22%	**-3%**
	Second	25%	24%	**-1%**
	Third	25%	27%	**+2%**
	Fourth	25%	27%	**+2%**
	Average Monthly Consumption (kWh)	590.15	614.47	**+4%**
Small Business (GS<50)	First	25%	23%	**-2%**
	Second	25%	24%	**-1%**
	Third	25%	26%	**+1%**
	Fourth	25%	27%	**+2%**
	Average Monthly Consumption (kWh)	2,319.69	2,473.38	**+7%**
C&I/Large Use (GS>50)	First	25%	24%	**-2%**
	Second	25%	25%	**0%**
	Third	25%	26%	**+2%**
	Fourth	25%	25%	**0%**
	Average Monthly Demand (kW)	337.57	355.21	**+5%**

Summary Results

Investment Trade-Offs

(%) indicates total percentages that selected response.	Rate Class Unweighted n (Weighted in brackets)		
	Residential n=3,692 (3,690)	**Small Business** n=114 (110)	**C&I** n=39
Targeted Reliability Investments to improve reliability for those experiencing poorer reliability than average.			
Accelerate spending	31%	23%	36%
Draft plan	40%	42%	33%
Reduce spending	29%	35%	31%
Community Growth Investments to support increased demand for electricity.			
Double rate of proactive replacement	16%	9%	5%
Most at-risk proactive upgrades	50%	50%	69%
Reactive upgrades (draft plan)	34%	41%	26%
Tree & Vegetation Trimming Emerging technology to better monitor the distribution system.			
Proceed with full technology	24%	21%	13%
Proceed with partial technology (draft plan)	51%	51%	67%
Delay technology to beyond 2030	24%	28%	21%
Mobile Application Launch of a mobile application to expand customer service offerings.			
Proceed with new application (draft plan)	59%	54%	54%
Delay new application beyond 2030	41%	46%	46%
Overall Evaluation of the Plan			
Spend more	20%	20%	21%
Spend according to the draft plan	58%	61%	62%
Spend less	12%	13%	13%
Social Permission [more + draft plan]	78%	80%	82%

Note: Response labels have been shortened for brevity. 'Other' and 'Don't know' not shown.

Summary Results

Rate Harmonization and Standby Rates

(%) indicates total percentages that selected response.	Rate Class Unweighted n (Weighted in brackets) **Residential** n=3,692 (3,690)	**Small Business** n=114 (110)	**C&I** n=39
Rate Harmonization			
I support it	44%	44%	46%
Don't like it, but feel it's necessary	27%	28%	28%
Opposed to it	13%	17%	3%
Social Permission [support + necessary]	71%	72%	74%
Extending Standby Rates to St. Thomas			
I support it	49%	48%	56%
Don't like it, but feel it's necessary	18%	19%	21%
Opposed to it	10%	12%	3%
Social Permission [support + necessary]	67%	68%	77%

Note: Response labels have been shortened for brevity. 'Don't know' not shown.

Residential Customers

Online Workbook Results

Online Workbook
Survey Design & Methodology

Field Dates

The **Residential Online Survey** was sent to all residential customers with an email address on file. Customers had an opportunity to complete the survey between **April 1st and April 30th, 2025**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the residential survey was sent to **32,510** customers from *engage@entegrus.com*. Reminder emails were sent on April 8th, April 16th, and April 24th 2025 to those who had not yet completed the survey.

Residential Online Survey Completes

A total of **3,692** (unweighted) Entegrus residential customers completed the online survey.

Sample Weighting

The residential online survey sample was weighted to n=3,690 proportionately by consumption quartiles and region in order to be representative of the broader Entegrus customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

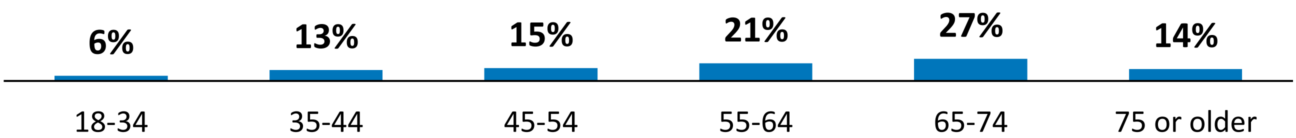
Region	Consumption Quartiles				Total
	Low	Low-Medium	Medium-High	High	
Chatham	325 (334)	306 (295)	279 (272)	274 (240)	1,184 (1,141)
St. Thomas	226 (247)	311 (293)	326 (297)	289 (294)	1,152 (1,130)
Strathroy	61 (65)	71 (82)	94 (99)	112 (132)	338 (378)
Rest	213 (276)	270 (253)	270 (254)	265 (257)	1,018 (1,041)
Total	825 (923)	958 (923)	969 (923)	940 (922)	3,692 (3,690)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.*

Demographic Breakdown

Residential

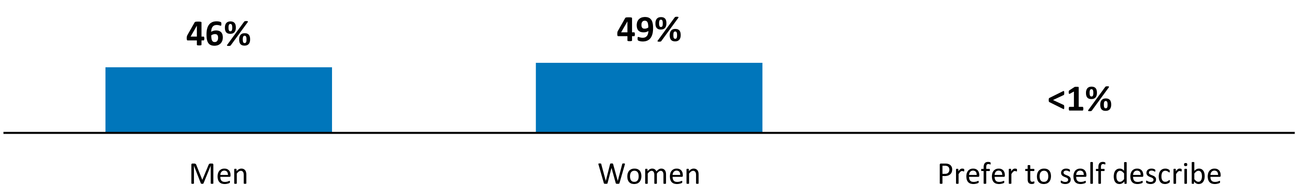
Q Age



"Prefer not to say" (3%) not shown.

n=3,690

Q Gender



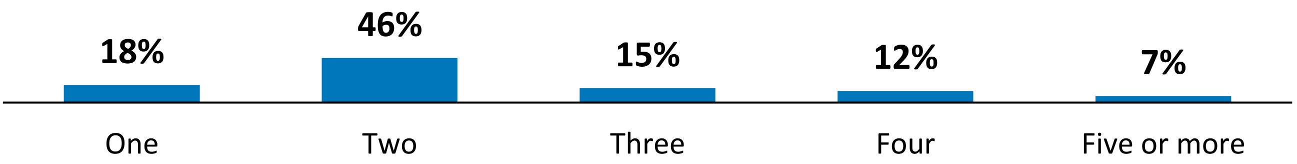
"Prefer not to say" (4%) not shown.

n=3,690

Demographic Breakdown
Continued

Residential

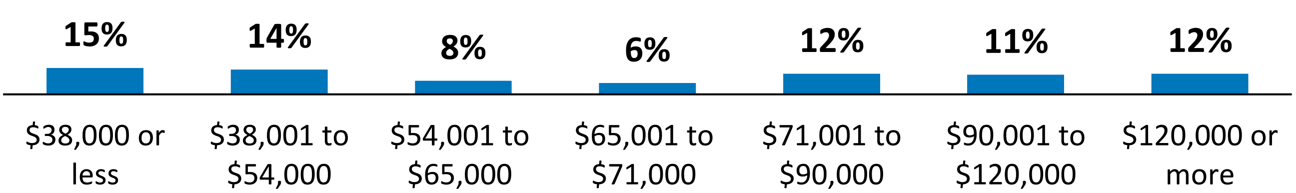
Q Household Size



"Prefer not to say" (3%) not shown.

n=3,690

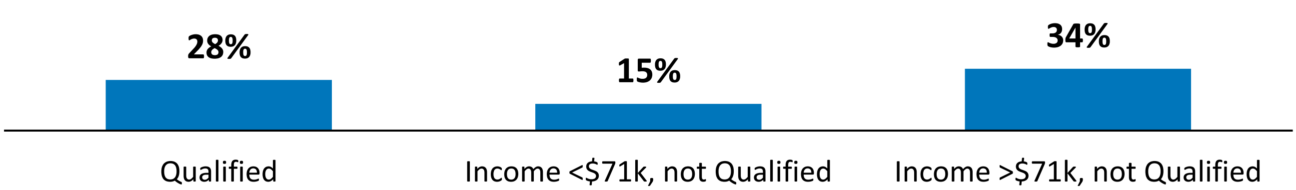
Q After Tax Household Income



"Prefer not to say" (23%) not shown.

n=3,690

Q **LEAP/OESP Qualification** (based on household size and income)



"Prefer not to say" (23%) not shown.

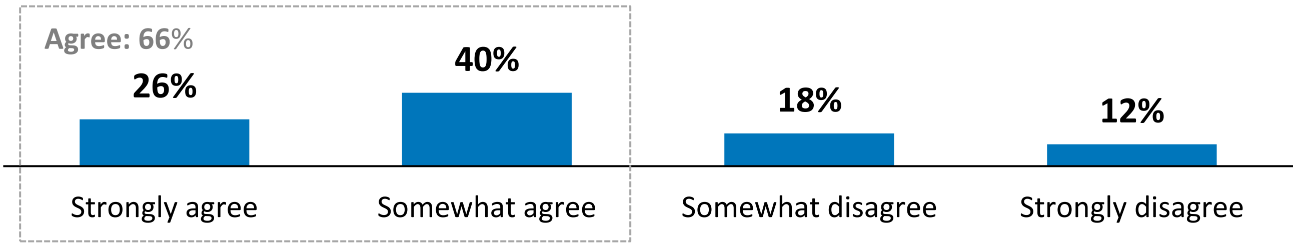
n=3,690

Environmental Controls

Residential

To what extent do you agree or disagree with the following statements?

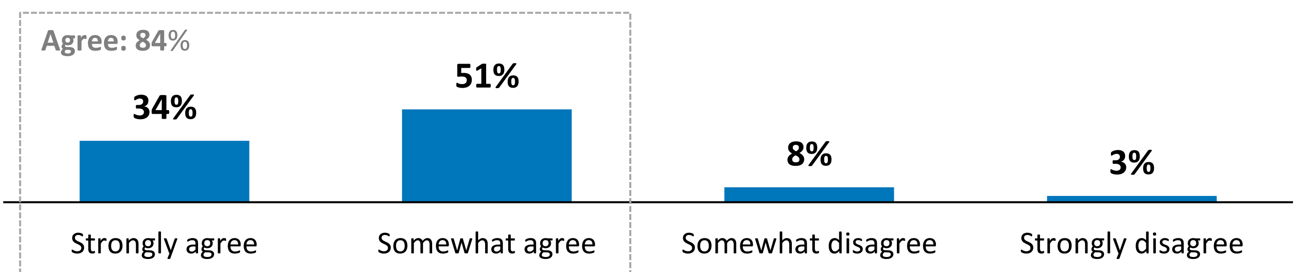
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=3,690

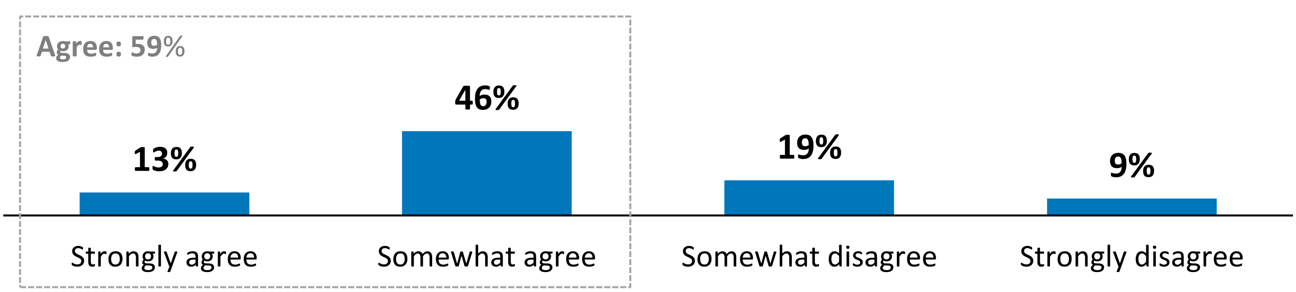
Q Customers are well served by the electricity system in Ontario.



"Don't know/no opinion" (4%) not shown.

n=3,690

Q Customers are protected with respect to the price we pay for electricity.



"Don't know/no opinion" (13%) not shown.

n=3,690

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Welcome to Entegrus' customer engagement survey!

The purpose of this survey is to get your feedback on Entegrus' upcoming draft investment plan.

- **Who has been invited to participate?** All Entegrus customers will be invited to participate in this survey. It's important that we hear from a wide range of customers from across the region.
- **What is this survey about?** This survey is focused on key decisions that Entegrus needs to make before finalizing their investment plans.
- **Why participate?** Your electricity rates pay for this plan and Entegrus must demonstrate that customer feedback was incorporated into its plans.
- **How long will the survey take?** The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. The survey is best completed on a laptop or tablet.

Those who complete the survey will be invited to enter a draw to win one (1) of five (5) $500 cash prizes.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Entegrus to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Entegrus in any identifiable way.

INNOVATIVE RESEARCH GROUP

Entegrus Customer Engagement Survey
Planning for the Future: 2026-2030 Investment Plan

Before we begin… a bit more about this survey!

Typically, every five years, local distributors like Entegrus are required to file an application with the Ontario Energy Board (OEB) to set rates.

However, as an outcome of the 2018 merger with St. Thomas Energy, Entegrus rates have increased at, or below, the rate of inflation since 2018.

Now, for the first time since the merger, Entegrus will be filing its next rate application that will cover the years 2026-2030.

In this process, Entegrus' rate application will be examined in detail and, again, Entegrus must demonstrate that customer needs and priorities were factored into this process.

Throughout 2024, nearly 2,000 Entegrus customers participated in surveys to aid in the development of Entegrus' draft plans.

Today, Entegrus is looking for your input to ensure that the plans they developed are, in fact, aligned with what customers want and expect.

Later this year, **Entegrus will present its proposed plans and input provided by customers to the OEB.**

You don't need to be an electricity expert to participate. This survey is focused on basic choices and provides the background information you need to answer the questions.

So, what are we going to talk about?

Today's survey will focus on two broad categories.

1. First, we need to ensure that we're all on the same page regarding Entegrus' role in the broader electricity system.
2. Second, you will be asked some questions about specific investment decisions that Entegrus needs to make to finalize their plans.

Familiarity & Experience

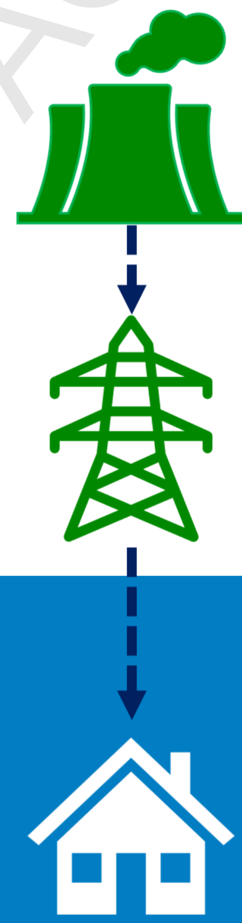
Entegrus' role in Ontario's electricity system

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

What is Entegrus' role in Ontario's electricity system?

Ontario's electricity system is made up of three key components: **generation**, **transmission** and **distribution**.



Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources. About half comes from nuclear power. The remainder comes from a mix of hydroelectric, natural gas, wind and solar. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity.

Transmission

How electricity travels across Ontario

Once electricity is generated, it must be transported to communities across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Most of this system is owned and operated by Hydro One.

Local Distribution

How electricity is delivered to you

Entegrus is responsible for the local distribution system, which takes electricity from transmission lines and brings it to your community.

Entegrus builds and maintains power lines, transformers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

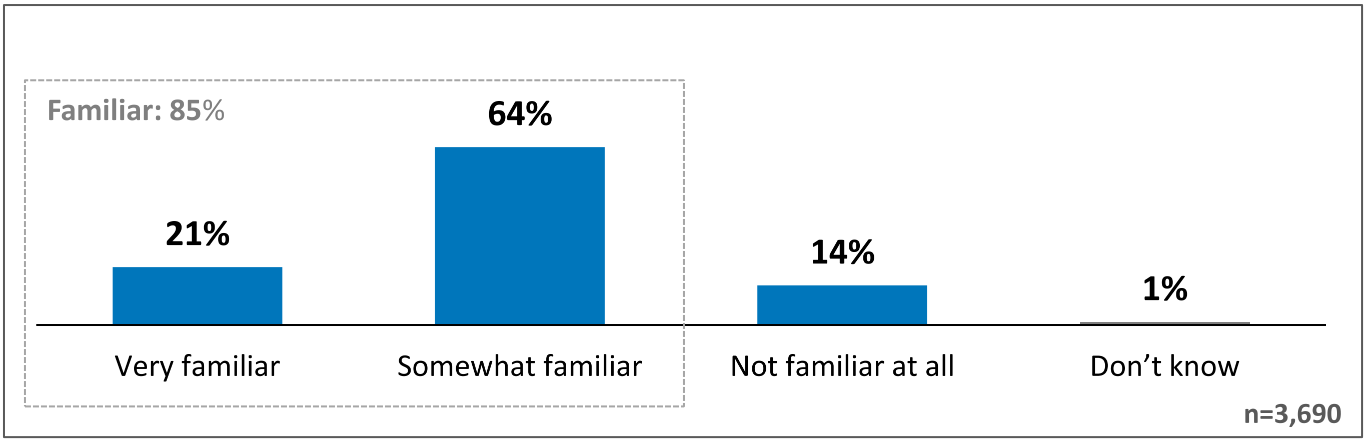
Entegrus does <u>not</u> generate electricity or set electricity prices.

Familiarity & Experience

Familiarity with Entegrus' role in the system

Residential

Q How familiar are you with **Entegrus**, which operates the electricity distribution system in your community?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very familiar	25%	18%	16%	20%	20%	22%
Somewhat familiar	62%	65%	68%	64%	64%	63%
Not familiar at all	12%	17%	14%	14%	14%	14%
Don't know	1%	1%	1%	1%	1%	1%
Familiar (Very + Somewhat)	**87%**	**83%**	**85%**	**85%**	**85%**	**85%**

INNOVATIVE RESEARCH GROUP

Familiarity & Experience

Familiarity with Entegrus' role in the system

Residential

Q How familiar are you with **Entegrus**, which operates the electricity distribution system in your community?

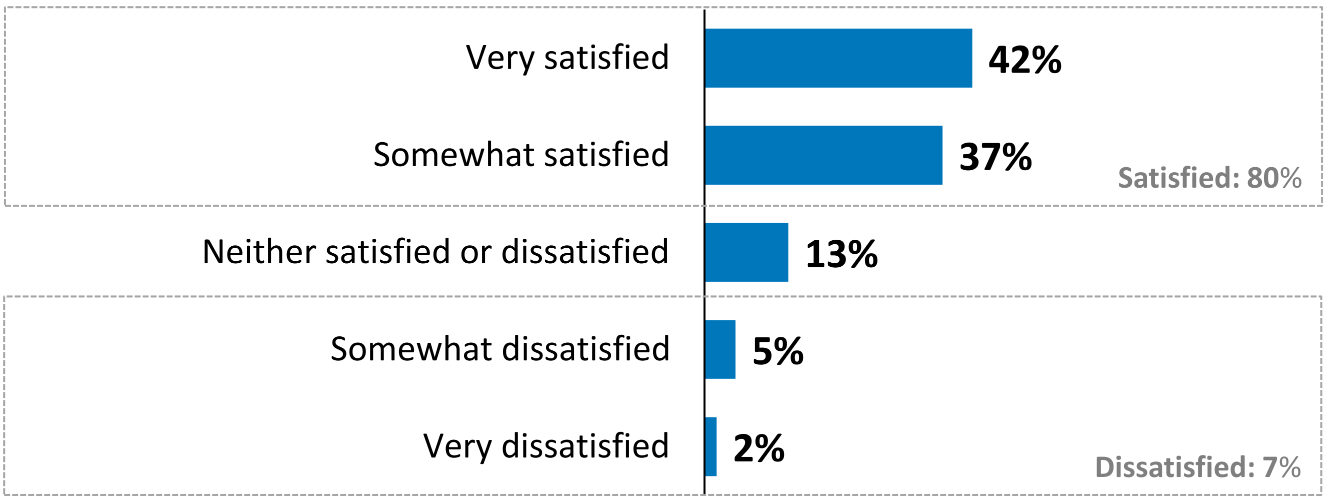
	Consumption Quartiles					LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very familiar	21%	19%	21%	21%	23%	21%	19%	24%
Somewhat familiar	64%	64%	64%	64%	64%	62%	65%	64%
Not familiar at all	14%	15%	15%	14%	13%	16%	15%	12%
Don't know	1%	2%	1%	1%	1%	1%	<1%	<1%
Familiar (Very + Somewhat)	**85%**	**83%**	**84%**	**85%**	**86%**	**83%**	**84%**	**88%**

Familiarity & Experience

Overall satisfaction with Entegrus

Residential

Q Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that you receive?



"Don't know" (<1%) not shown.

n=3,690

	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very satisfied	44%	45%	44%	37%	35%	56%
Somewhat satisfied	37%	36%	38%	40%	41%	32%
Neither satisfied nor dissatisfied	13%	13%	13%	14%	15%	9%
Somewhat dissatisfied	4%	4%	4%	7%	6%	2%
Very dissatisfied	2%	1%	1%	3%	2%	1%
Don't know	1%	<1%	1%	<1%	<1%	<1%
Satisfied (Very + Somewhat)	**81%**	**80%**	**82%**	**77%**	**76%**	**87%**
Dissatisfied (Very + Somewhat)	**6%**	**6%**	**5%**	**9%**	**9%**	**3%**

Familiarity & Experience

Overall satisfaction with Entegrus

Residential

Q Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that you receive?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very satisfied	42%	45%	46%	40%	37%	43%	47%	43%
Somewhat satisfied	37%	36%	38%	38%	38%	36%	37%	37%
Neither satisfied nor dissatisfied	13%	12%	11%	14%	16%	12%	11%	13%
Somewhat dissatisfied	5%	5%	3%	5%	7%	5%	4%	5%
Very dissatisfied	2%	2%	1%	2%	2%	2%	1%	1%
Don't know	<1%	1%	1%	<1%	<1%	1%	--	<1%
Satisfied (Very + Somewhat)	**80%**	**81%**	**84%**	**79%**	**75%**	**80%**	**84%**	**80%**
Dissatisfied (Very + Somewhat)	**7%**	**6%**	**4%**	**7%**	**9%**	**8%**	**5%**	**7%**

Familiarity & Experience

More about Entegrus

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

More about Entegrus

Entegrus owns and operates distribution systems **serving 17 communities in Southwestern Ontario**, stretching between Wheatley (to the west), St. Thomas (to the east), Parkhill (to the north) and Lake Erie (to the south).

- Most of the initial system expansion in the Entegrus communities occurred between 1950 and 1970**.** Some of the equipment in Entegrus' distribution system is more than 50 years old.
- Entegrus' service territory today is a product of multiple mergers and amalgamations dating back to the late-1990s – most recently the amalgamation with **St. Thomas Energy** in 2018.
- Today, Entegrus has operation centres in both Chatham and St. Thomas.

Familiarity & Experience

Portion of bill that goes to Entegrus

Residential

Entegrus Main Version

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much of my electricity bill goes to Entegrus?

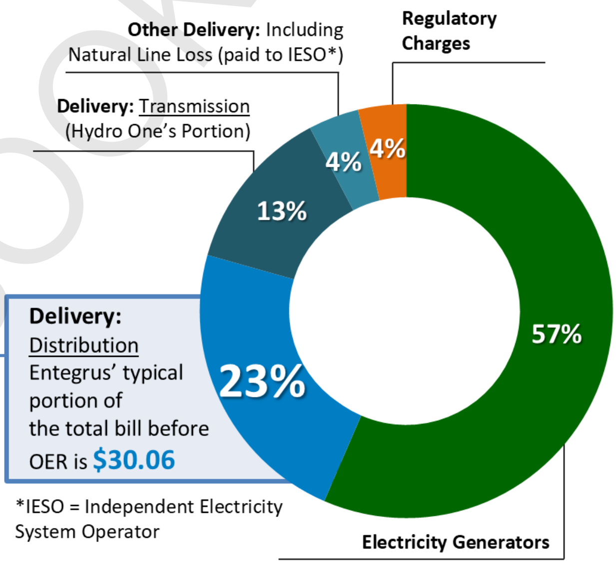
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.
- **For a typical residential customer, 23% of the total bill or about $30 goes to Entegrus each month.**
- The rest of your bill payment goes to power generation and transmission companies, taxes, and regulatory agencies.

Sample Entegrus Monthly Bill
(based on consumption of 750 kWh as of May 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 18.2 c/kWh	21.33
Mid-Peak (mid price) @ 12.2 c/kWh	16.47
Off-Peak (lowest price) @ 8.7 c/kWh	36.48
Delivery	52.24
Regulatory Charges	4.94
Total Electricity Charges	**$131.47**
HST	17.09
Ontario Electricity Rebate	(-$17.22)
Total Amount	**$131.34**



The chart above is based on a total bill of $131.47 excluding the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 750kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

Note: In the workbook, sample bills differed based on rate zone (Entegrus main or St.Thomas).

Familiarity & Experience

Portion of bill that goes to Entegrus

Residential

St. Thomas Version

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much of my electricity bill goes to Entegrus?

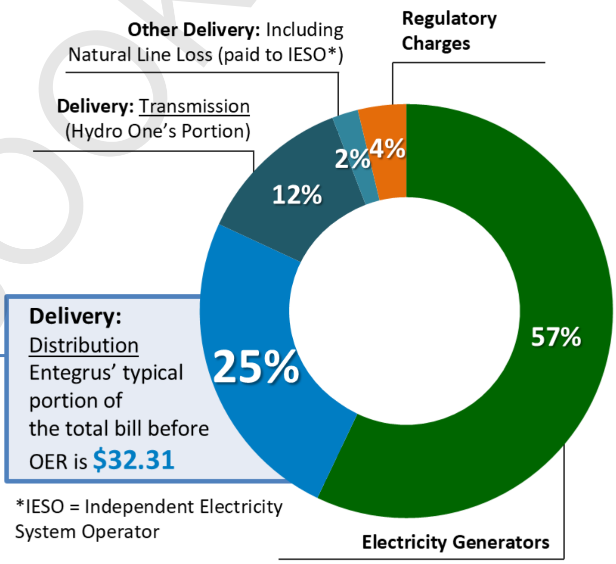
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.
- **For a typical residential customer, 25% of the total bill or about $32 goes to Entegrus each month.**
- The rest of your bill payment goes to power generation and transmission companies, taxes, and regulatory agencies.

Sample Entegrus Monthly Bill
(based on consumption of 750 kWh as of May 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 18.2 c/kWh	21.33
Mid-Peak (mid price) @ 12.2 c/kWh	16.47
Off-Peak (lowest price) @ 8.7 c/kWh	36.48
Delivery	50.95
Regulatory Charges	4.93
Total Electricity Charges	**$130.16**
HST	16.92
Ontario Electricity Rebate	(-$17.05)
Total Amount	**$130.03**



*IESO = Independent Electricity System Operator

The chart above is based on a total bill of $130.16 excluding the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

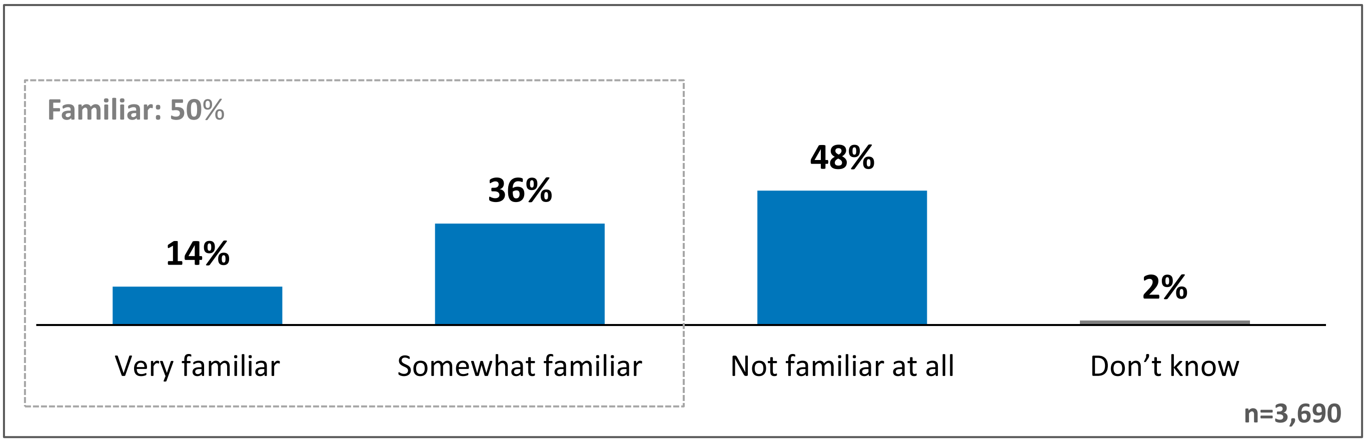
The sample bill above uses an average consumption level of 750kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

Note: In the workbook, sample bills differed based on rate zone (Entegrus main or St.Thomas).

Familiarity & Experience
Bill familiarity

Residential

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Entegrus**?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Very familiar	16%	12%	13%	13%	15%	12%
Somewhat familiar	38%	32%	33%	41%	38%	33%
Not familiar at all	45%	54%	53%	45%	45%	54%
Don't know	2%	2%	1%	1%	2%	1%
Familiar (Very + Somewhat)	**54%**	**45%**	**46%**	**54%**	**53%**	**45%**

Familiarity & Experience
Bill familiarity

Residential

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Entegrus**?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Very familiar	14%	13%	13%	14%	16%	14%	10%	16%
Somewhat familiar	36%	35%	37%	37%	37%	36%	38%	38%
Not familiar at all	48%	50%	49%	48%	46%	47%	51%	46%
Don't know	2%	2%	1%	2%	1%	3%	1%	1%
Familiar (Very + Somewhat)	**50%**	**48%**	**50%**	**50%**	**53%**	**50%**	**48%**	**54%**

Summary of Investment Plan

What Entegrus has heard so far

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

What has Entegrus heard from customers so far?

In the summer of 2024, nearly 2,000 Entegrus customers participated in a series of surveys. These surveys included all types of customers, ranging from residential to commercial and industrial. Here's what Entegrus heard:

1	**Most customers prioritize affordability, followed closely by ensuring reliable service.**
2	**Customers largely support investment in maintaining current system reliability.**
3	**Many want Entegrus to proactively invest to ensure customers in higher growth areas do not experience a decline in reliability.**
4	**Customers would like to see Entegrus invest in new technologies when customer benefits are clear.**
5	**Many customers support improvements in customer service that make it easier to view and report outages.**

Summary of Investment Plan

Challenges facing Entegrus' grid

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Challenges facing Entegrus' grid

There are many challenges facing the electricity grid that Entegrus will seek to manage in its draft investment plan covering the years 2026-2030. The key challenges facing Entegrus' grid include:

- **Aging and deteriorating infrastructure, some of which is more than 50 years old.**
- **The increased frequency of severe weather in communities served by Entegrus.**
- **Rising costs related to inflation and supply chain disruptions.**
- **Increasing demand for electricity in communities served by Entegrus.**
- **The changing ways customers are using electricity and adoption of new technology.**
- **An increasing industry focus on cyber security and IT systems.**
- **An increasing industry focus on adoption of new technologies.**

In addition to the challenges above, Entegrus is also going to need to be responsive to the **ongoing threat of U.S. tariffs**. The threat of these tariffs make it increasingly difficult to forecast and plan, as costs could change and businesses could shift priorities, resulting in less than anticipated demand for electricity.

Regardless, Entegrus has prepared its 2026-2030 draft investment plan to address these challenges with the ultimate objective of being responsive to external pressures while providing safe and reliable electricity to communities at a reasonable cost.

Summary of Investment Plan

Objectives of the draft investment plan

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

What is Entegrus' draft plan?

In addition to feedback received from customers, Entegrus has developed its draft plans based on information and input from internal engineering and technical experts who closely monitor the pressures on the distribution system, develop solutions to address these challenges, and recommend investments that inform its plans.

Below are some of the highlights of Entegrus' 2026-2030 draft plan.

1. **Manage rising costs and limiting potential rate increases.**
2. **Maintain current levels of reliability, while targeting improvements for customers experiencing poorer reliability than average.**
3. **Prepare the system to support community growth and respond to new customer requests.**
4. **Explore new technologies to make Entegrus' operations more efficient and offer clear customer benefits.**
5. **Offer customers new ways to view account information, track, and report outages in real-time.**
6. **Ensure that all 17 communities served by Entegrus pay the same for the service they receive.**
7. **Prepare the grid to be more resilient in the face of more frequent severe weather.**

Throughout the remainder of this survey, you will be asked to provide feedback that focuses on these key objectives – where there may be opportunities to do more or less than is currently planned.

But first, Entegrus will tell you about some of the efforts to manage rising costs.

Summary of Investment Plan

What Entegrus is doing to keep costs down

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

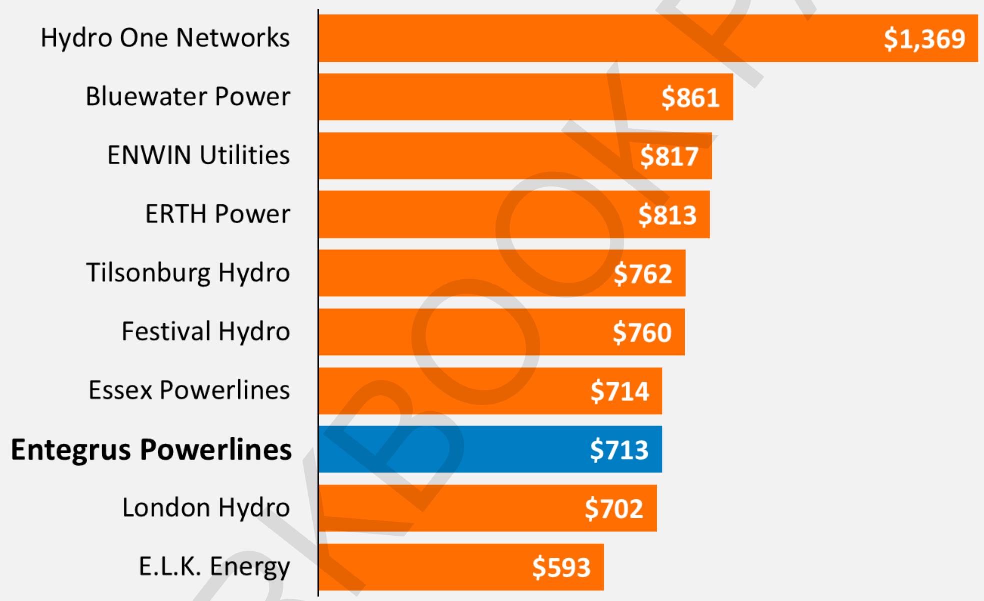
What is Entegrus doing to keep costs down?

According to the latest data published by the Ontario Energy Board, Entegrus is among the most efficient utilities in Southwestern Ontario, as measured by the total cost per customer.

Below is a regional comparison across Southwestern Ontario.

Southwestern Ontario Utility Comparison: Total Cost per Customer

Source: 2023 OEB Electricity Distributor Scorecard



In an effort to keep costs down, Entegrus is a member of the GridSmartCity Co-operative, an organization that brings together 15 Ontario electricity distributors to collaborate and share knowledge, skills and expertise – with some of the goals being increased efficiency and cost savings through economies of scale.

Cost saving benefits include negotiated group rates for services and group savings on the procurement of wood poles, cables, wires, and transformers.

Additionally, through its 2018 merger with St. Thomas Energy, Entegrus continues to see annual savings of approximately $1.7 million each year through shared operating, maintenance, and administrative costs.

Summary of Investment Plan

Cost of Entegrus' draft plan to customers

Residential

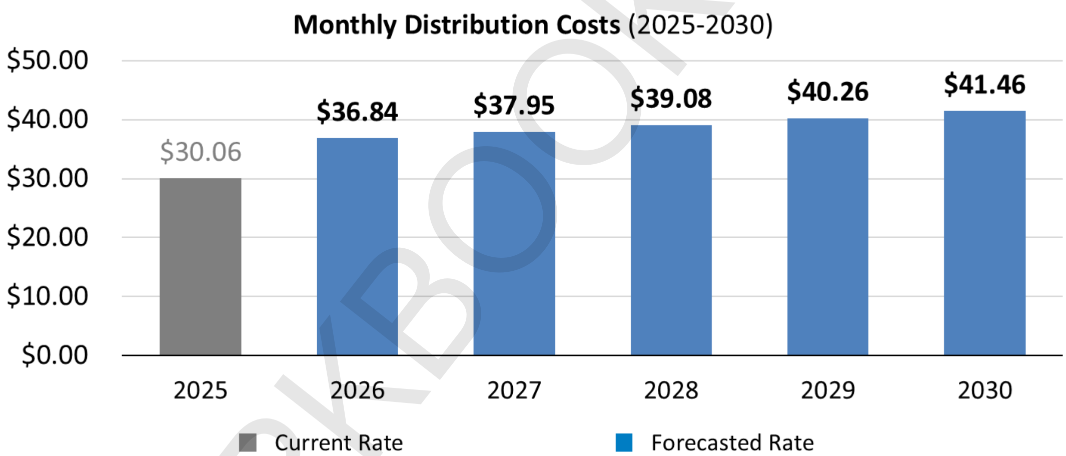
Entegrus Main Version

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much will Entegrus' draft plan cost me?

To achieve the outcomes outlined in Entegrus' draft plan, it is estimated that the typical **residential** customer would see the distribution portion of their electricity bill increase by **$11.40** from $**30.06 today (2025)** to a proposed rate of **$41.46 by 2030**.



These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical residential customer is assumed to use 750 kWh per month and enrolled under Time-of-Use Regulated Price Plan.

Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas).

Summary of Investment Plan

Cost of Entegrus' draft plan to customers

Residential

St. Thomas Version

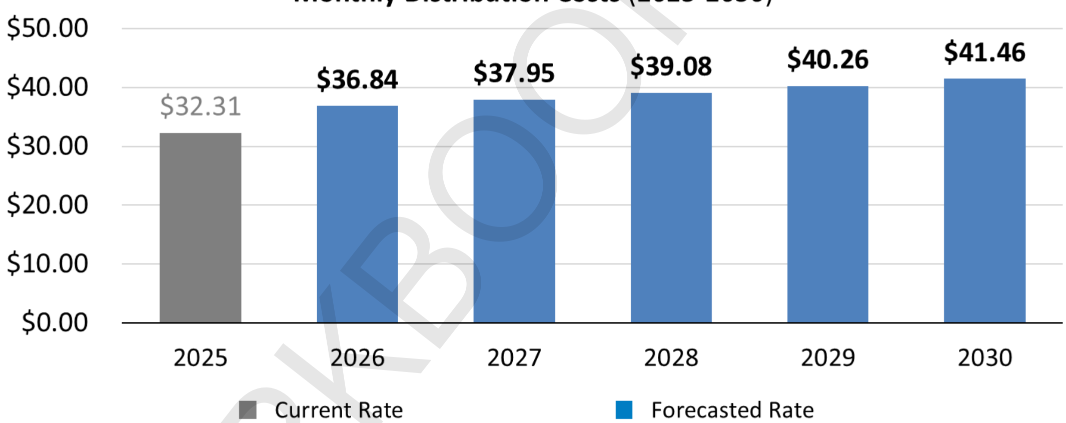
Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much will Entegrus' draft plan cost me?

To achieve the outcomes outlined in Entegrus' draft plan, it is estimated that the typical **residential** customer would see the distribution portion of their electricity bill increase by **$9.15** from **$32.31 today (2025)** to a proposed rate of **$41.46 by 2030**.

Monthly Distribution Costs (2025-2030)



These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical residential customer is assumed to use 750 kWh per month and enrolled under Time-of-Use Regulated Price Plan.

Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas).

Summary of Investment Plan

Actual and forecasted budgets

Residential

Entegrus Customer Engagement Survey

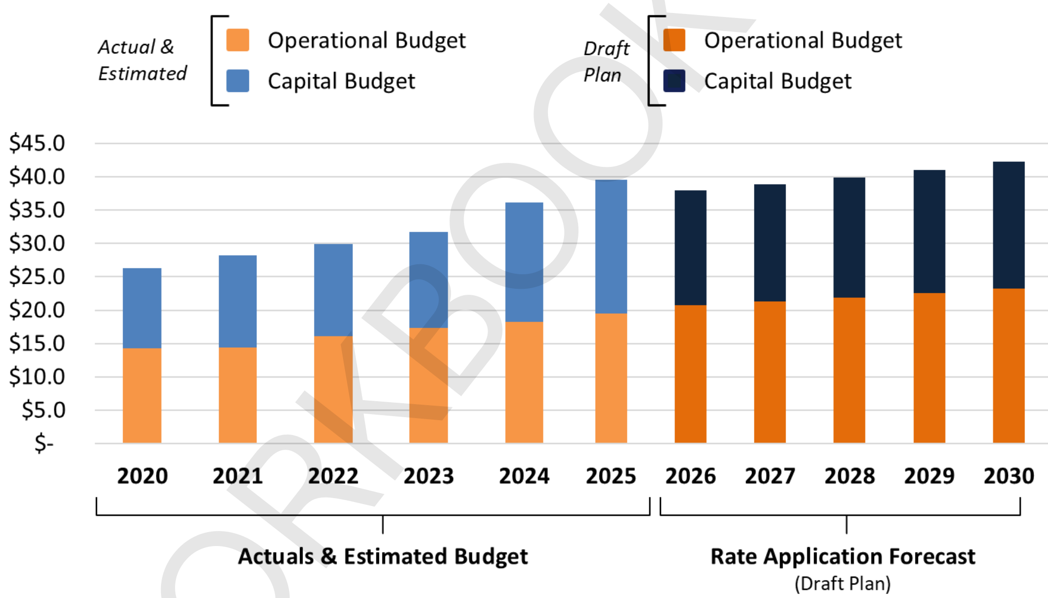
Planning for the Future: 2026-2030 Investment Plan

How does Entegrus plan future investments in the system?

Like most businesses, Entegrus manages both an operating budget and a capital budget.

- The **operating budget** covers recurring expenses, such as the maintenance of assets and tools, customer services, running all business systems and processes, as well as the cost of employees who ensure these activities are completed.
- The **capital budget** includes the costs to build the system, such as the overhead and underground infrastructure, computers and information systems, vehicles and facilities. These items, once purchased, provide long term benefits for many years to come.

Actual and Forecasted Budgets per year ($ millions)



The final budget for 2026-2030 will be adjusted to reflect customer feedback collected through this engagement and any necessary adjustments prior to filing with the OEB. The OEB and other stakeholders will complete an extensive review before rates are set for 2026-2030.

Before these plans can be finalized, Entegrus needs your feedback on the objectives discussed earlier.

Entegrus must demonstrate that their investment plans are directly responsive to customer needs and preferences.

Summary of Investment Plan

How to make choices

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How do I make choices?

The remainder of this survey asks for your input on **4 key choices** that will affect the services you receive and the rates that you pay from 2026-2030.

- Each choice has a summary of the options that Entegrus is considering. In many cases, that includes options that would see Entegrus spend less or spend more than what is currently being proposed in the draft investment plan.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance.

Recall, Entegrus is entirely funded by the rates paid by its customers.

That means, the investments that are discussed in the subsequent pages are directly funded by customers.

Investment Trade-Offs

Targeted reliability investments

Residential

Entegrus Customer Engagement Survey

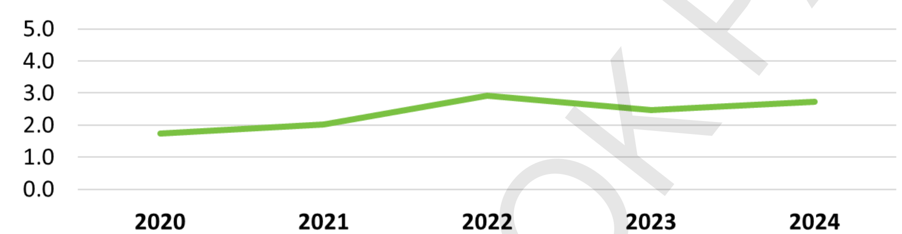
Planning for the Future: 2026-2030 Investment Plan

Choice 1 of 4: Targeted Reliability Investments

First, let's discuss the reliability of the electricity grid in your community.

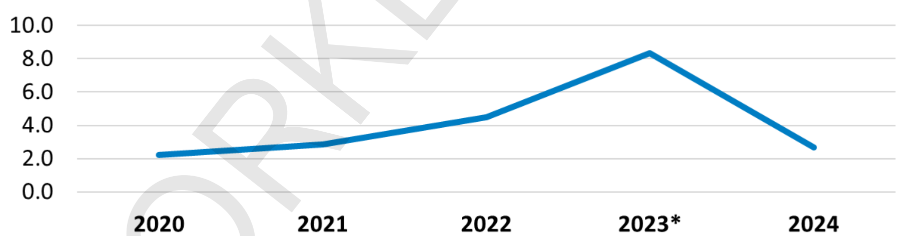
On average, between 2020 and 2024, the typical Entegrus customer has experienced **about 2.4 outages per year**.

Average number of outages (outages per customer)



Over the same period, the **average duration of an outage has been about 4 hours**. Meaning, when the power does go out, Entegrus is typically able to restore power in about four hours.

Average Outage Duration (outage length in hours per customer)



*** In 2023, Entegrus communities experienced four significant storms, resulting in an above average length of time that customers were without power.**

It's important to keep in mind that these are system averages, and that your actual experience may be different. Customers experience different levels of reliability, depending on where they live, the design of the system, and the condition of the equipment supplying them.

Investment Trade-Offs

Targeted reliability investments

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 1 of 4: Targeted Reliability Improvements

In the current draft plan, Entegrus' planners have identified a series of targeted investments to improve reliability for those customers that experience poorer reliability than average. This includes automated switches that allow Entegrus to automatically reroute power during outages, in part, reducing the length of time customers are without power.

Entegrus could accelerate spending in this area, resulting in reliability improvements for more customers who have historically experienced poorer reliability than average.

Or Entegrus could reduce spending in this area, resulting in reliability improvements for fewer customers who have historically experienced poorer reliability than average.

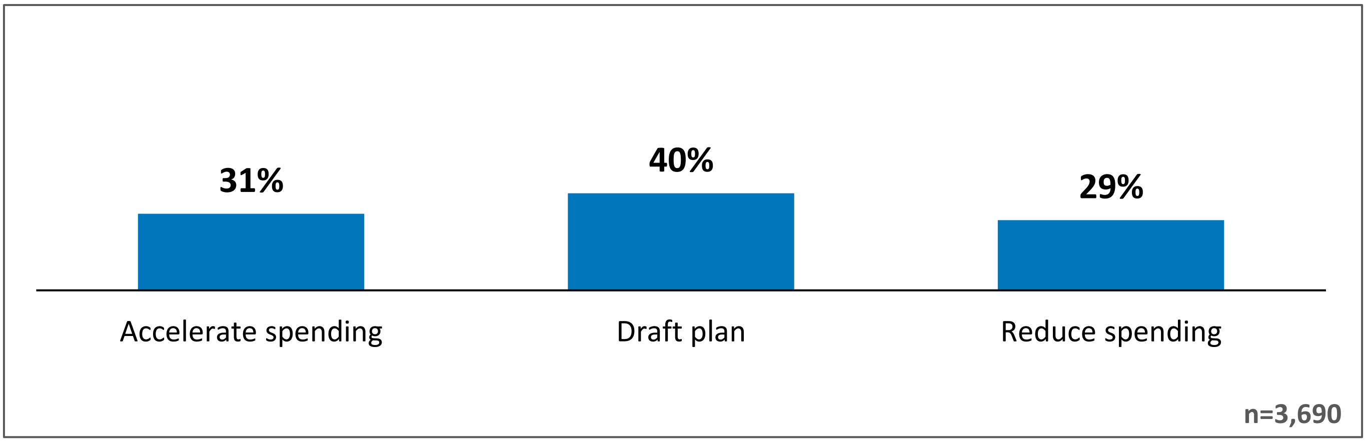
Investment Trade-Offs

Targeted reliability investments

Residential

Q Which of the following options do you prefer?

Option	Expected Outcome(s)
Accelerate spending ***$0.25*** *more on monthly bill by 2030*	• Make further targeted investments to improve reliability for more customers who experience significantly poorer reliability than average.
Draft plan *Within proposed rate increase*	• Make targeted investments to improve reliability for some customers who experience significantly poorer reliability than average.
Reduce spending ***$0.13*** *less on monthly bill by 2030*	• Reduce targeted investments to improve reliability for customers experiencing significantly poorer reliability than average.



Investment Trade-Offs

Targeted reliability investments

Residential

Q Which of the following options do you prefer?

	Region					Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Accelerate spending	31%	32%	32%	30%	29%	24%	45%
Draft plan	40%	40%	41%	46%	39%	41%	39%
Reduce spending	29%	29%	27%	24%	32%	35%	16%

	Consumption Quartiles				LEAP/OESP Qualification		
	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Accelerate spending	30%	33%	30%	31%	26%	35%	34%
Draft plan	42%	41%	42%	38%	40%	42%	40%
Reduce spending	29%	26%	28%	32%	34%	23%	26%

Investment Trade-Offs

Targeted reliability investments

Residential

Q Additional Feedback (Optional)

Responses	%
Willing to pay more for improved reliability	1.5%
Cost of living pressure/financial strain	1.2%
Against increases/costs are too expensive	0.7%
Find efficiencies instead of customers paying more	0.5%
Current level of service is acceptable	0.5%
Infrastructure needs to be upgraded	0.5%
Dissatisfied with current reliability	0.4%
Need more information/have questions	0.3%
Increase is reasonable	0.2%
Entegrus is profit-driven	0.2%
Distrust in the engagement/rate increases are inevitable	0.2%
Bury lines/better maintenance	0.1%
Concerns over impacts of the tariff war	0.1%
Customers shouldn't pay for investments	0.1%
Other	0.4%
None/Don’t know	0.1%
No comment/No response	93.0%

Note: Only responses >0.1% shown.

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Preparing for community growth

Residential

Choice 2 of 4: Preparing for Community Growth

As more customers start getting electric vehicles, solar panels, or just generally continue to use electricity differently, more and more equipment will need to be upgraded to accommodate these changes. If demand increases quicker than expected in a specific community, this could strain the system and lead to equipment failing more frequently.

Transformers are a critical piece of equipment that help accommodate this changing electricity usage. They are located throughout your community and are usually mounted on top of wooden poles.

As a rule of thumb, the larger the transformer, the more electricity it can serve to the homes and businesses on the other end of the wire. Today, the smaller transformers that have historically served residential homes are increasingly struggling to keep up with demand.

In the current draft plan, Entegrus will upgrade transformers reactively as they fail and install bigger transformers for new homes being constructed.

Alternatively, Entegrus could introduce a new program to proactively upgrade transformers that are most at risk of overloading and therefore failure. Proactive replacement can:

a) Help ensure that customers have access to enough electricity when they need it

b) Reduce the risk of need for reactive replacement – and reducing outage durations – when equipment does fail.

That said, proactive replacement does <u>not</u> necessarily reduce the current risk of outages. The benefit is more about preparing the grid for the future and minimizing future reliability risks.

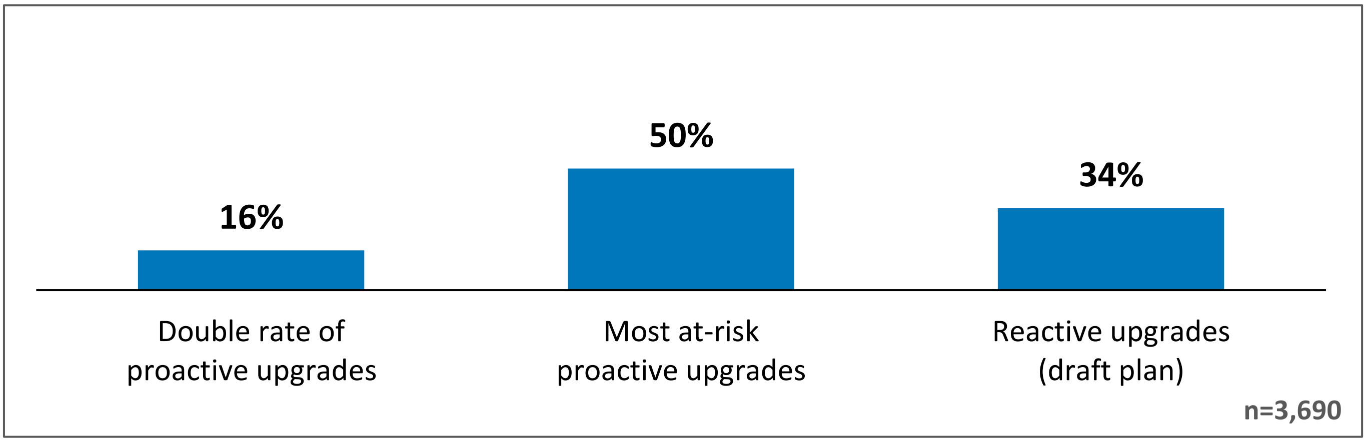
Investment Trade-Offs

Preparing for community growth

Residential

Q Which of the following options do you prefer?

Option	**Expected Outcome(s)**
Double rate of proactive upgrades ***$0.50 more** on monthly bill by 2030*	• Double the rate of proactive upgrades of most at-risk transformers • Further reduce the risk of outages due to transformer failures
Most at-risk proactive upgrades ***$0.25 more** on monthly bill by 2030*	• Proactively upgrade most at-risk transformers • Potentially reduce the risk of outages due to transformer failures
Reactive upgrades (draft plan) *Within proposed rate increase*	• Maximize the useful life of current transformers • Potential for higher levels of unplanned outages due to transformer failures



Investment Trade-Offs

Preparing for community growth

Residential

Q Which of the following options do you prefer?

	Region					Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Double rate of proactive upgrades	16%	15%	17%	15%	17%	12%	24%
Most at-risk proactive upgrades	50%	50%	50%	51%	50%	50%	50%
Reactive upgrades (draft plan)	34%	35%	33%	33%	33%	38%	25%

	Consumption Quartiles				LEAP/OESP Qualification		
	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Double rate of proactive upgrades	15%	17%	16%	17%	15%	16%	20%
Most at-risk proactive upgrades	50%	52%	52%	46%	49%	52%	50%
Reactive upgrades (draft plan)	35%	31%	32%	37%	36%	32%	30%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Preparing for community growth

Residential

Q Additional Feedback (Optional)

Responses	%
Support proactive approaches/Entegrus should prepare for growth	1.2%
Find efficiencies instead of customers paying more	0.6%
Only replace transformers when needed	0.6%
Not all customers should have to pay	0.5%
Against increases/costs are too expensive	0.5%
Skeptical of significant demand growth/EV uptake	0.3%
Need to improve the system/equipment failure concerns	0.3%
Distrust in the engagement/rate increases are inevitable	0.2%
Need more information/have questions	0.2%
Dissatisfied with current reliability	0.1%
Customers shouldn't pay for investments	0.1%
Other	0.4%
None/Don’t know	0.3%
No comment/No response	94.7%

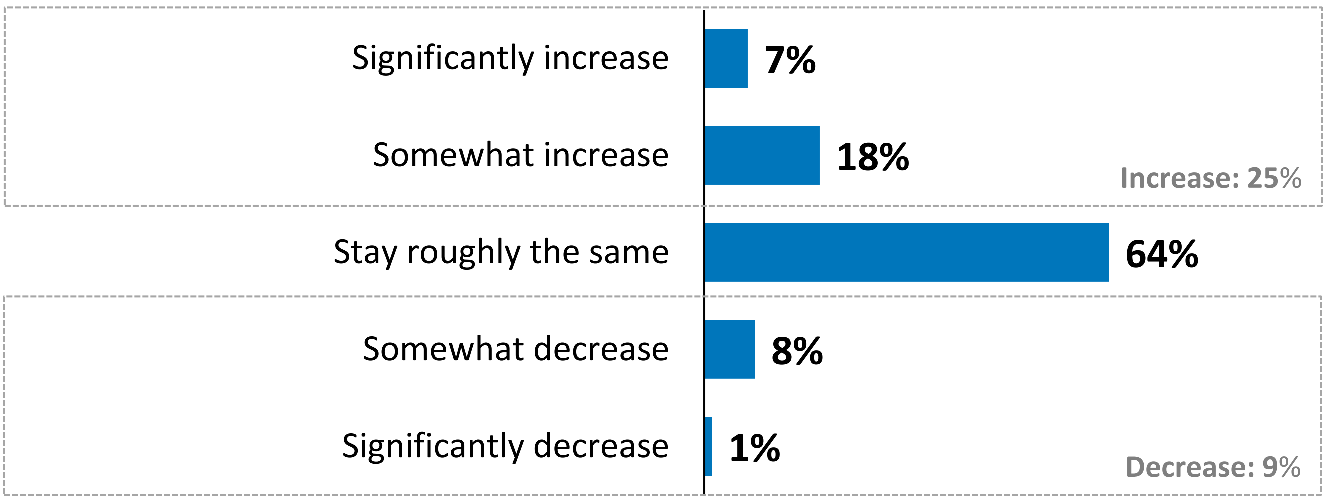
Note: Only responses >0.1% shown.

Investment Trade-Offs

Preparing for community growth

Residential

Q In the next five years, do you anticipate your electricity usage will increase, decrease, or stay roughly the same?



"Don't know" (2%) not shown.

n= 3,690

	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Significantly increase	8%	6%	5%	7%	9%	3%
Somewhat increase	18%	18%	16%	19%	18%	19%
Stay roughly the same	62%	65%	71%	62%	61%	69%
Somewhat decrease	9%	7%	6%	8%	9%	7%
Significantly decrease	1%	1%	1%	1%	2%	1%
Don't know	2%	2%	2%	2%	2%	2%
Increase (Very + Somewhat)	**26%**	**24%**	**21%**	**26%**	**27%**	**22%**
Decrease (Very + Somewhat)	**11%**	**8%**	**7%**	**9%**	**10%**	**7%**

Investment Trade-Offs

Preparing for community growth

Residential

Q In the next five years, do you anticipate your electricity usage will increase, decrease, or stay roughly the same?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Significantly increase	7%	4%	6%	8%	10%	9%	5%	6%
Somewhat increase	18%	21%	19%	17%	16%	19%	16%	20%
Stay roughly the same	64%	67%	65%	63%	60%	57%	72%	64%
Somewhat decrease	8%	6%	7%	8%	11%	9%	5%	8%
Significantly decrease	1%	1%	1%	2%	2%	1%	<1%	1%
Don't know	2%	2%	2%	2%	2%	3%	1%	1%
Increase (Very + Somewhat)	**25%**	**25%**	**25%**	**25%**	**25%**	**29%**	**22%**	**26%**
Decrease (Very + Somewhat)	**9%**	**6%**	**8%**	**10%**	**13%**	**10%**	**6%**	**9%**

Investment Trade-Offs

Tree and vegetation trimming

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 3 of 4: Tree and Vegetation Trimming

The third investment Entegrus would like your feedback on is on emerging technology to better monitor Entegrus' distribution system.

Entegrus serves 17 communities and has thousands of trees across its service territory and in proximity to its lines.

On a regular basis, Entegrus must ensure those trees remain a safe distance from electrical equipment like poles and wires. Currently, on a multi-year cycle, Entegrus goes community-by-community to trim trees and other vegetation. In a typical year, outages due to tree contacts account for approximately 7-19% of all customer outages.

In previous surveys, many customers said that they would support Entegrus piloting new technology that would use satellites to build a 3D model of vegetation and lines across the communities served by Entegrus. This technology would allow for more precise planning to minimize the magnitude of trimming required.

As planning has progressed, Entegrus has identified an opportunity to expand this pilot to even further minimize tree contacts and reduce potential delays during large infrastructure projects. This would include augmenting the satellite modeling with more frequent and targeted ground-based scans, getting into more difficult to reach areas.

Currently, the draft plan includes piloting the satellite scans, however, Entegrus would like to hear if you would like them to do more or less. To keep costs down, Entegrus could continue with its current time-based approach to tree trimming and vegetation management.

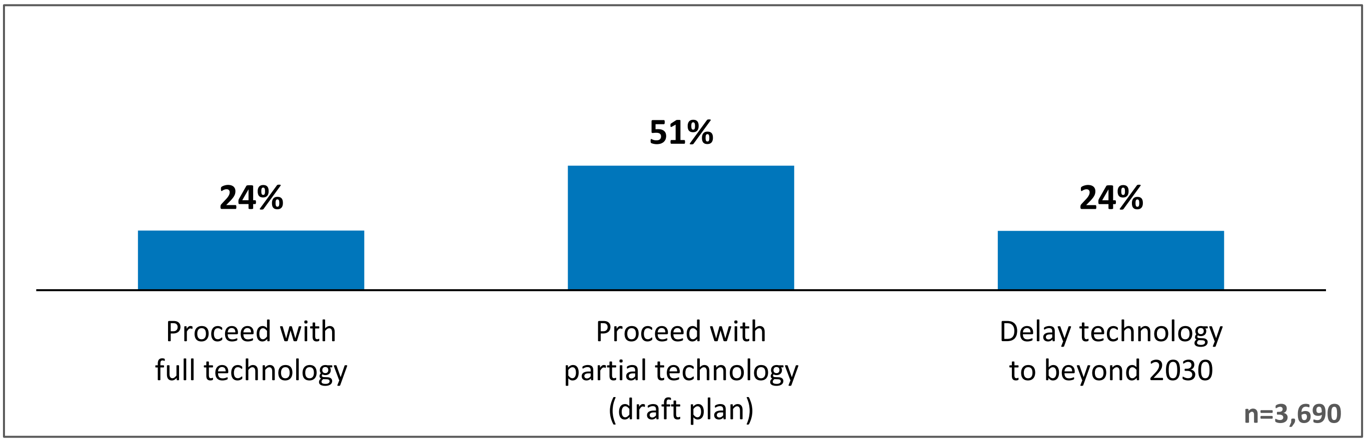
Investment Trade-Offs

Tree and vegetation trimming

Residential

Q Which of the following options do you prefer?

Option	Expected Outcome(s)
Proceed with full technology ***$0.15*** *<u>more</u> on monthly bill by 2030*	• Allow targeted tree trimming and scanning of harder to reach areas in Entegrus' service territory, not completed with partial technology approach • May further reduce the number of outages caused by tree contacts than with partial technology
Proceed with <u>partial</u> technology (draft plan) *Within proposed rate increase*	• Allow for more targeted tree and vegetation trimming than the typical, manual approach • May reduce the number of outages caused by tree contacts
Delay technology to beyond 2030 ***$0.40*** *<u>less</u> on monthly bill by 2030*	• Continue with the current approach to tree and vegetation trimming • Unchanged likelihood of outages caused by tree contacts



Investment Trade-Offs

Tree and vegetation trimming

Residential

Q Which of the following options do you prefer?

	Region					Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Proceed with full technology	24%	25%	26%	19%	24%	22%	30%
Proceed with partial technology (draft plan)	51%	52%	50%	58%	50%	50%	53%
Delay technology to beyond 2030	24%	24%	24%	23%	26%	28%	17%

	Consumption Quartiles				LEAP/OESP Qualification		
	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Proceed with full technology	25%	25%	22%	25%	26%	24%	27%
Proceed with partial technology (draft plan)	52%	52%	54%	47%	48%	56%	53%
Delay technology to beyond 2030	23%	23%	24%	28%	27%	20%	21%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Tree and vegetation trimming

Residential

Q Additional Feedback (Optional)

Responses	%
Be proactive about tree and vegetation trimming	0.7%
Increase is reasonable	0.7%
Bury lines/better maintenance	0.5%
Find efficiencies instead of customers paying more	0.5%
Cost of living pressure/financial strain	0.5%
Explore other options	0.4%
Need more information/have questions	0.2%
Concern over personal vegetation management issues	0.2%
Avoid planting trees near powerlines	0.2%
Wait until technology advances more	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
Against tree removal/environmental concerns	0.1%
Other	0.3%
None/Don't know	0.1%
No comment/No response	95.3%

Note: Only responses >0.1% shown.

Investment Trade-Offs

Mobile application upgrades

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 4 of 4: Mobile Application Upgrades

The fourth investment Entegrus would like your feedback on is on a mobile application.

Again, in earlier research, many customers expressed interest in expanded customer service offerings, specifically an app that includes **access to My Account (the Entegrus online customer account portal)**, **an outage map** and the **ability to report outages**.

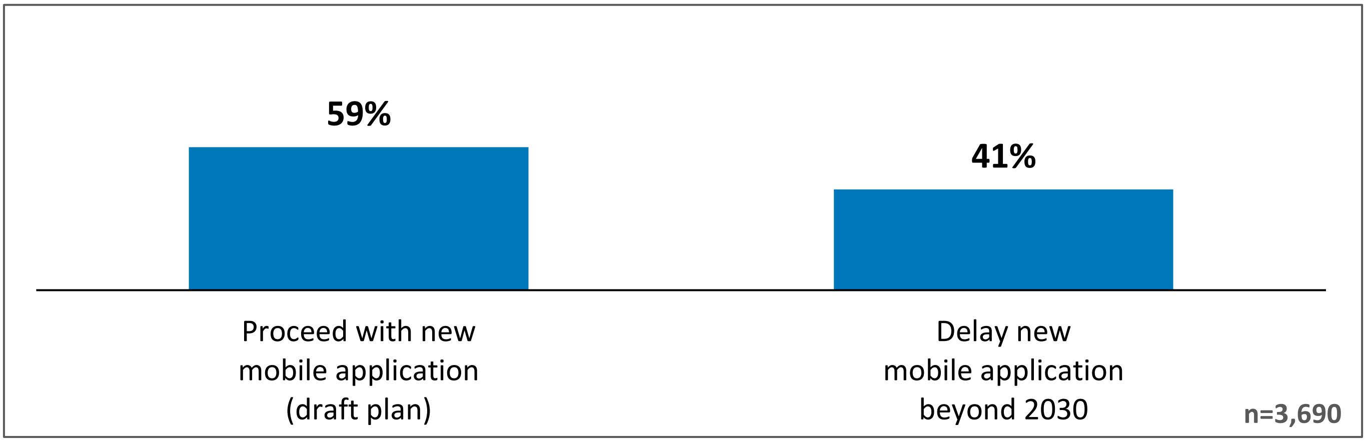
In response to this feedback, Entegrus' draft plan includes investment to support the launch of a mobile application that provides these features. While this investment is responsive to customer feedback, Entegrus would like to confirm that customers would like them to proceed, knowing the full cost of this investment.

Investment Trade-Offs
Mobile application upgrades

Residential

Q Which of the following options do you prefer?

Option	Expected Outcome(s)
Proceed with new mobile application (draft plan) *Within proposed rate increase*	• Allow customers the ability to access MyAccount, an outage map, and report outages online through a mobile application.
Delay new mobile application beyond 2030 ***$0.20*** *less on monthly bill by 2030*	• Continue with Entegrus' existing customer service offerings without proceeding with a new mobile application.



Investment Trade-Offs

Mobile application upgrades

Residential

Q Which of the following options do you prefer?

	Region					Bill Impact	
	Overall	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Proceed with new mobile application (draft plan)	59%	58%	59%	64%	58%	55%	66%
Delay new mobile application beyond 2030	41%	42%	41%	36%	42%	45%	34%

	Consumption Quartiles				LEAP/OESP Qualification		
	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Proceed with new mobile application (draft plan)	58%	59%	59%	59%	59%	59%	63%
Delay new mobile application beyond 2030	42%	41%	41%	41%	41%	41%	37%

Investment Trade-Offs

Mobile application upgrades

Residential

Q Additional Feedback (Optional)

Responses	%
Don't believe a mobile app is necessary/preference for website	2.1%
Support for new mobile application	1.1%
Focus on improving the website instead	0.4%
Against increases/costs are too expensive	0.4%
Technology accessibility issues for seniors and non-tech users	0.2%
Focus on reliability and infrastructure instead	0.2%
Cost of living pressure/financial strain	0.2%
Use alternative outage communication channels (radio, text, etc)	0.1%
Other	0.5%
None/Don't know	0.1%
No comment/No response	94.7%

Note: Only responses >0.1% shown.

Investment Trade-Offs

Finalizing Choices

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choices Calculator

Throughout this survey, you have been asked about 4 key choices from that could impact your rates. Below is a summary of your choices.

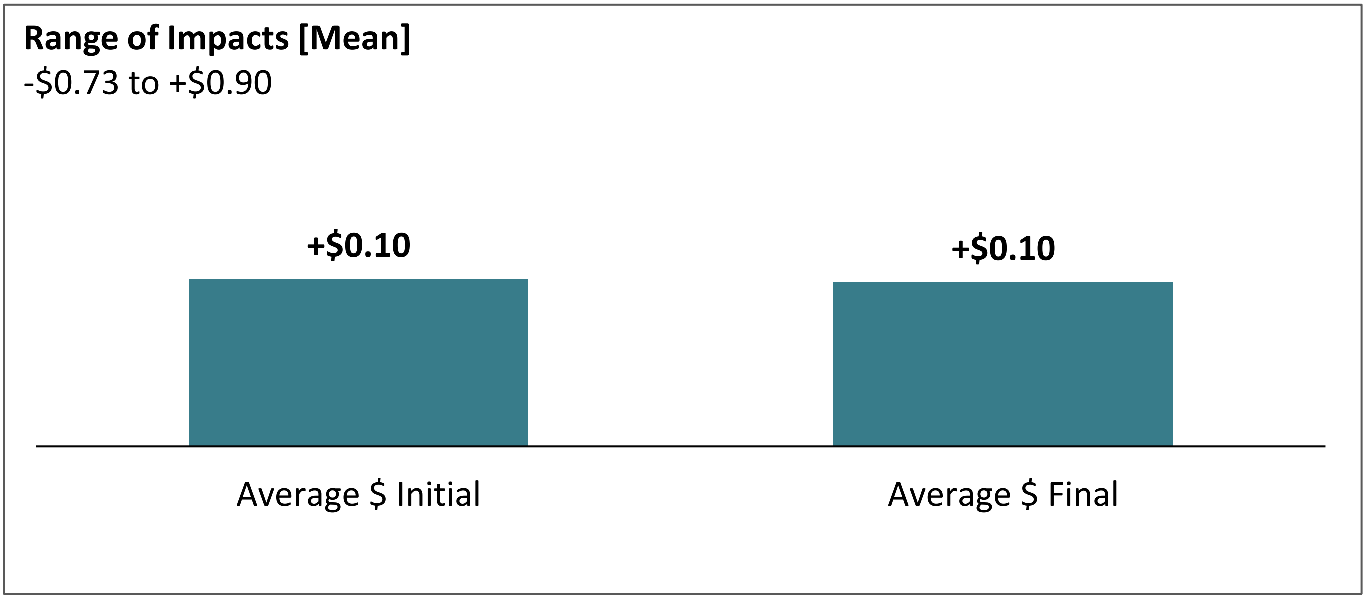
At the bottom of this page, you will find the total rate impact of your choices.

Please review your answers and change your responses if you desire, and your potential rate impact will be re-calculated. You can adjust your choices until you reach the best balance for you.

Investment Trade-Offs
Finalizing Choices

Residential

Residential Customer Bill Impact Change and Magnitude of Bill Impact



About the "Range of Impacts"

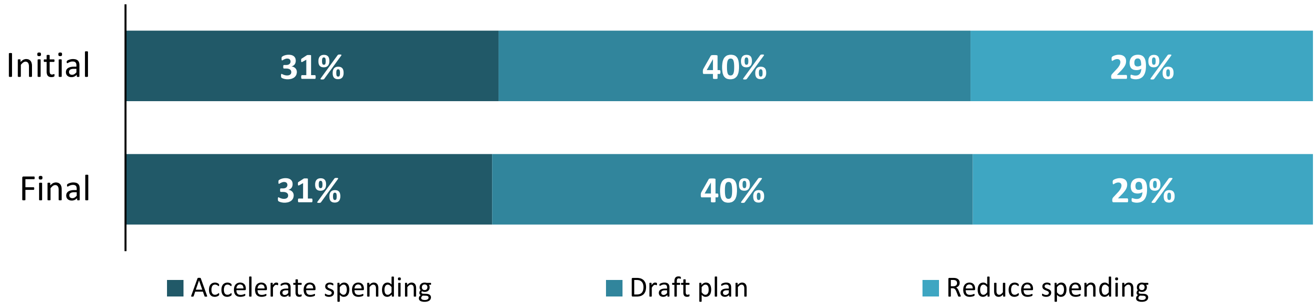
The "Range of Impacts" signifies the highest and lowest possible range of bill impacts above and beyond the Draft Plan. For instance, if a customer, where possible, were to select the biggest increase for each choice, their bill impact would result in **$0.90 more** per month by 2030 when compared to the draft plan. If they were to select the biggest decrease for each choice, it would result in **$0.73** less per month by 2030 when compared to the draft plan.

Investment Trade-Offs

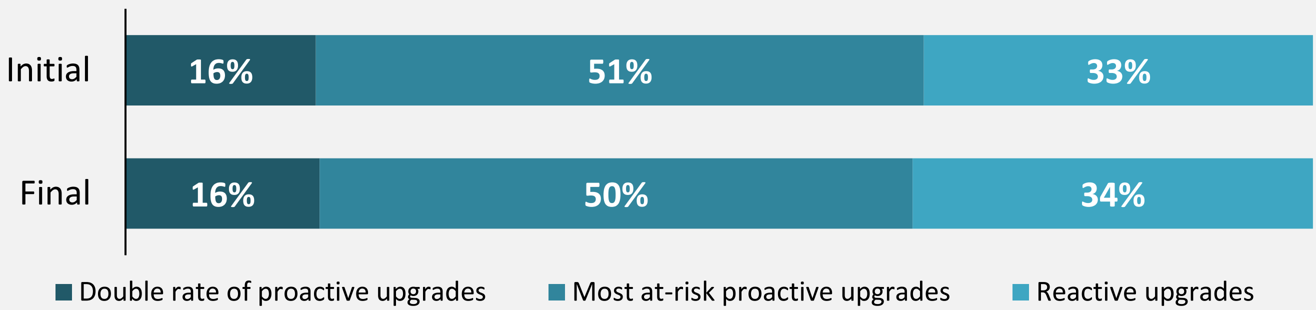
Finalizing Choices

Residential

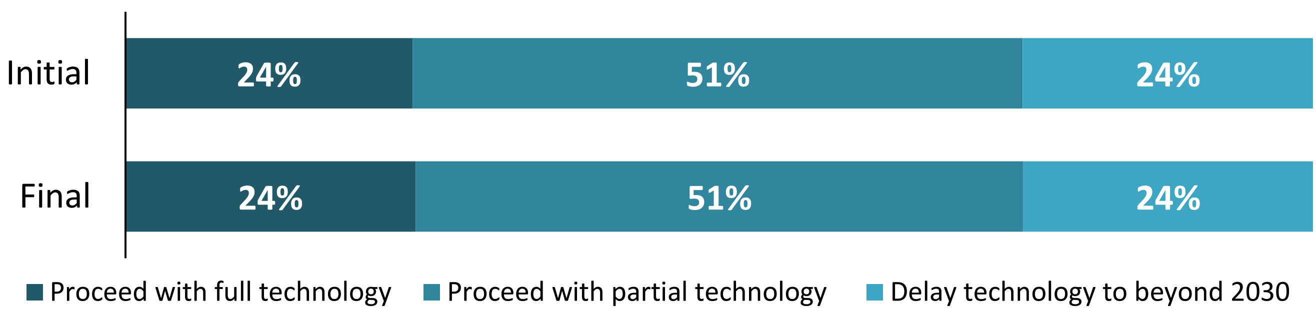
Targeted Reliability Improvements



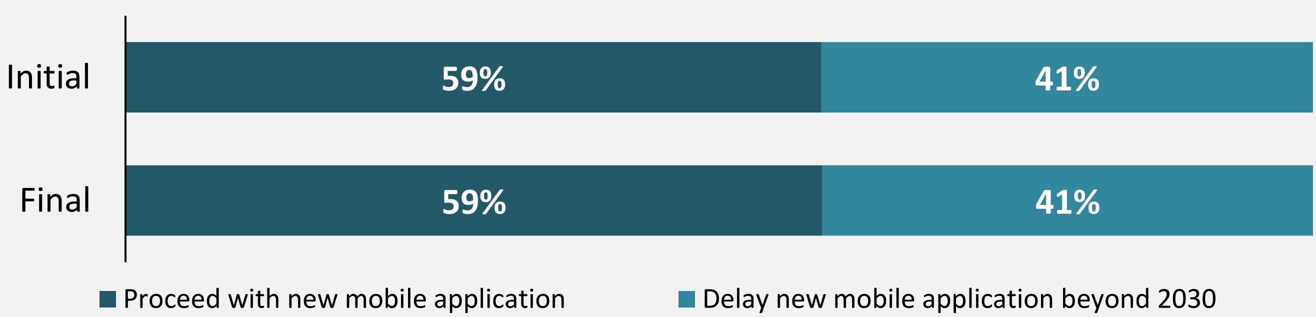
Preparing for Community Growth



Tree and Vegetation Trimming



Mobile Application Upgrades



Investment Trade-Offs

Overall evaluation of the plan

Residential

Entegrus Main Version

Entegrus Customer Engagement Survey

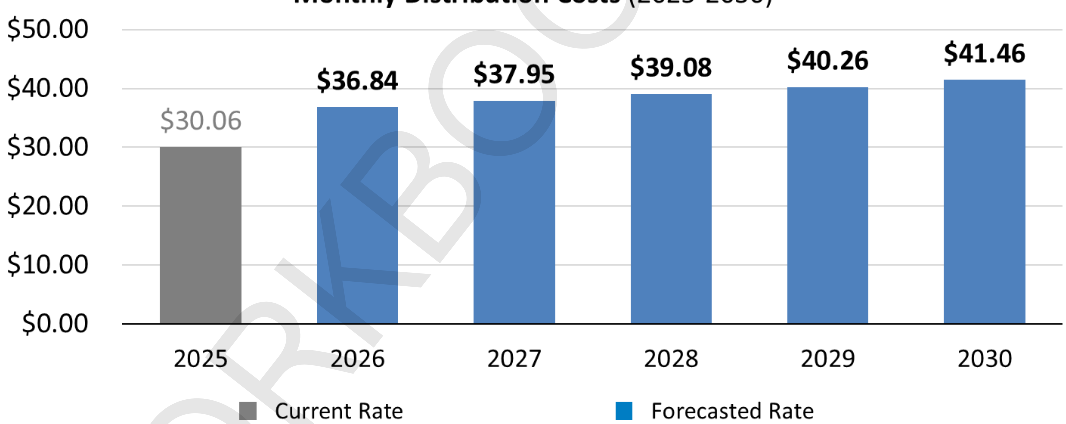
Planning for the Future: 2026-2030 Investment Plan

Assessing Entegrus' draft 2026-2030 plan

Entegrus has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Entegrus would like to know how you feel about the overall draft plan.

It is estimated that the typical **residential** customer would see the distribution portion of their electricity bill increase by **$11.40** from **$30.06 today (2025)** to a proposed rate of **$41.46 by 2030**.

Monthly Distribution Costs (2025-2030)



These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical residential customer is assumed to use 750 kWh per month and enrolled under Time-of-Use Regulated Price Plan.

Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas).

Investment Trade-Offs

Overall evaluation of the plan

Residential

St. Thomas Version

Entegrus Customer Engagement Survey

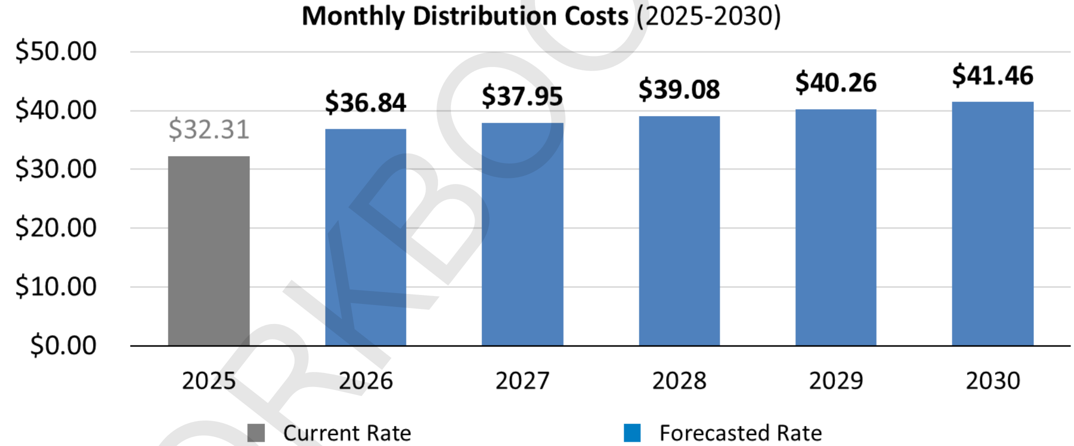
Planning for the Future: 2026-2030 Investment Plan

Assessing Entegrus' draft 2026-2030 plan

Entegrus has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Entegrus would like to know how you feel about the overall draft plan.

It is estimated that the typical **residential** customer would see the distribution portion of their electricity bill increase by **$9.15** from **$32.31 today (2025)** to a proposed rate of **$41.46 by 2030**.

Monthly Distribution Costs (2025-2030)



These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical residential customer is assumed to use 750 kWh per month and enrolled under Time-of-Use Regulated Price Plan.

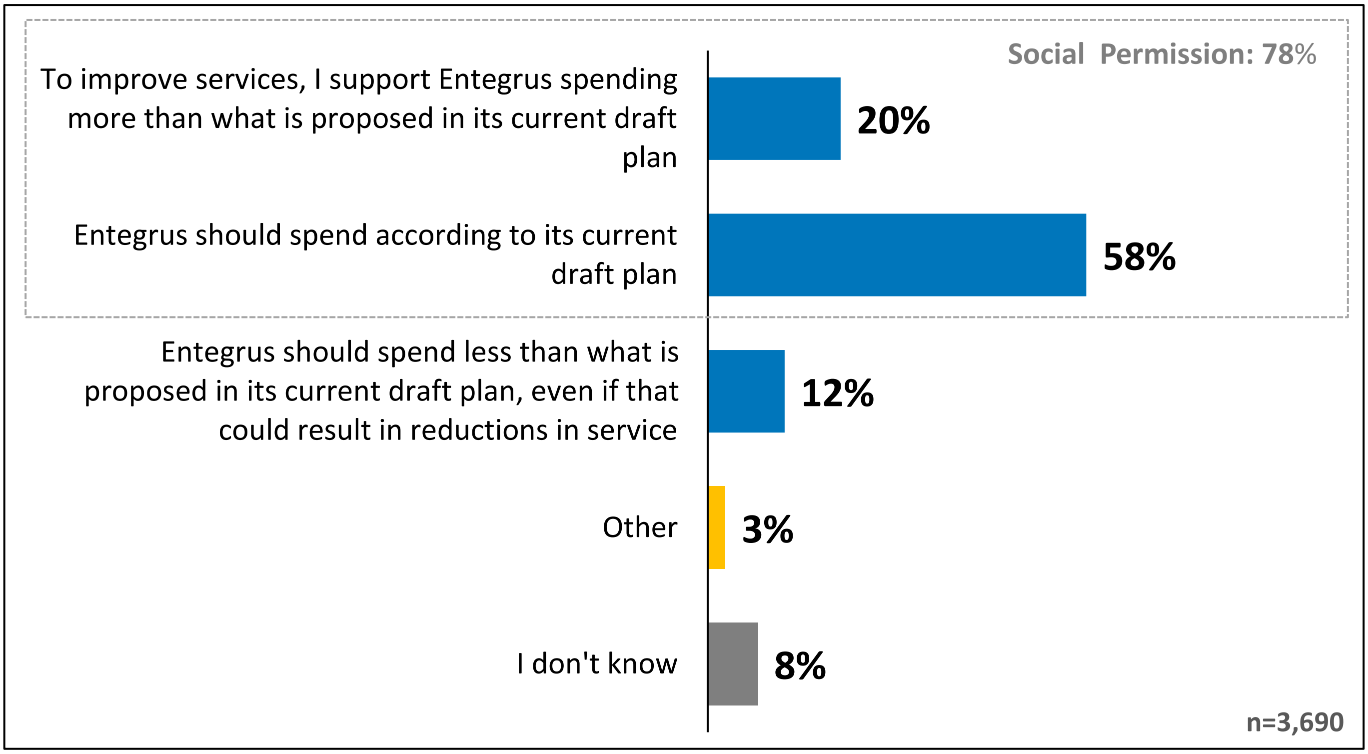
Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas).

Investment Trade-Offs

Overall evaluation of the plan

Residential

Q Considering what you have learned about Entegrus' 2026–2030 draft plan, which of the following best represents your point of view?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Spend more	21%	20%	21%	19%	15%	30%
Spend according to plan	57%	58%	58%	58%	59%	55%
Spend less	12%	12%	11%	12%	14%	7%
Other	3%	2%	3%	3%	3%	1%
I don't know	8%	7%	7%	8%	8%	7%
Social Permission	**78%**	**79%**	**79%**	**77%**	**74%**	**85%**

Investment Trade-Offs

Overall evaluation of the plan

Residential

Q

Considering what you have learned about Entegrus' 2026–2030 draft plan, which of the following best represents your point of view?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Spend more	20%	18%	22%	20%	21%	18%	22%	24%
Spend according to plan	58%	60%	59%	58%	54%	57%	61%	58%
Spend less	12%	12%	9%	12%	14%	12%	10%	11%
Other	3%	2%	3%	2%	3%	3%	2%	2%
Don't know	8%	8%	7%	8%	8%	10%	6%	4%
Social Permission	**78%**	**79%**	**80%**	**78%**	**75%**	**75%**	**82%**	**83%**

Investment Trade-Offs

Final comments on the draft plan

Residential

Q Do you have any final comments regarding Entegrus' draft plan for 2026–2030 and the proposed rate increase?

Responses	%
Lower rates/urge for affordability	3.8%
Be proactive to improve reliability/minimize outages	2.4%
Find efficiencies instead of customers paying more	1.3%
Need more information/have questions	0.9%
Support the draft plan/find it reasonable	0.9%
Support the increase/investments are necessary	0.9%
Financial strain on seniors/fixed-income individuals	0.8%
Satisfied with the service/pleased with Entegrus	0.7%
Customers shouldn't pay for investments	0.7%
Concerns of increases due to the high cost of living/inflation	0.5%
Increase should be more gradual/initial increase is too high	0.5%
Distrust in the engagement/rate increases are inevitable	0.5%
Reduce management costs/salaries	0.5%
Be transparent/communicative with customers about the proposed rate increases	0.3%
Focus on the environment/sustainability	0.2%
Improve customer service experience	0.2%
Concerns over impacts of the tariff war	0.1%
Other	0.6%
None/Don't know	2.1%
No comment/No response	82.1%

Note: Only responses >0.1% shown.

Rate Harmonization

Impact of rate harmonization

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Rate Harmonization

A key principle for rates in Ontario is that similar customers should pay the same cost for similar service, regardless of where they are located within a utility service area. As a result of the 2018 amalgamation between Entegrus and St. Thomas Energy, this is not currently the case for all Entegrus customers.

Rate harmonization means bringing two sets of distribution rates into one harmonized rate so that all Entegrus customers in the same rate class pay the same for electricity distribution.

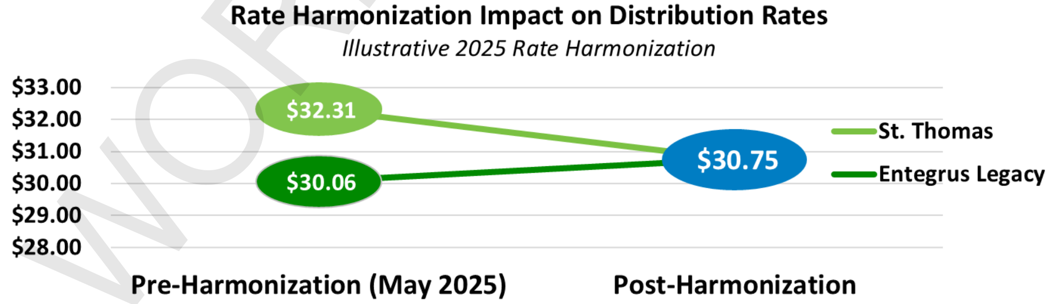
Since merging in 2018, there have been two different sets of rates – one set of rates for the 16 legacy Entegrus communities and one set of rates for St. Thomas.

How will it impact me?

Starting in 2026, Entegrus is planning to harmonize rates for all 17 communities. This means that some customers would have a small increase on their bill while others will see a small decrease. **This change will represent less than 1% of the typical total bill.**

Before proceeding, Entegrus would like your feedback on this proposed change.

The chart below shows the impact of rate harmonization on customer rates.



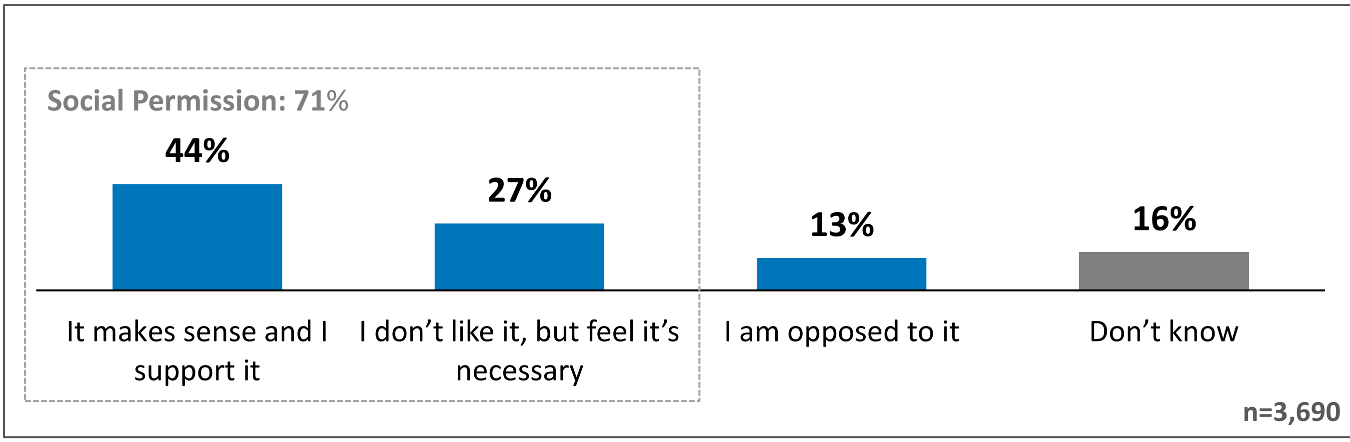
These illustrative estimates are calculated without the 2026 rate increase associated with the draft plan discussed throughout this survey and are subject to customer feedback and regulatory approval.

Rate Harmonization

Social permission on rate harmonization

Residential

Q Which of the following best describes how you feel about rate harmonization?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Support	39%	56%	43%	36%	37%	57%
Don't like it but necessary	31%	21%	30%	30%	30%	21%
Oppose	14%	8%	14%	18%	15%	9%
Don't know	16%	14%	14%	17%	17%	13%
Social Permission (Support + Necessary)	**70%**	**77%**	**72%**	**65%**	**67%**	**78%**

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Rate Harmonization

Social permission on rate harmonization

Residential

Q Which of the following best describes how you feel about rate harmonization?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Support	44%	45%	45%	43%	42%	41%	45%	49%
Don’t like it but necessary	27%	28%	29%	26%	26%	30%	30%	26%
Oppose	13%	12%	12%	14%	15%	13%	11%	13%
Don’t know	16%	15%	14%	17%	17%	16%	15%	12%
Social Permission (Support + Necessary)	**71%**	**73%**	**74%**	**69%**	**68%**	**71%**	**75%**	**75%**

INNOVATIVE RESEARCH GROUP

Standby Rates

Impact of standby rates

Residential

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Standby Rates

Standby rates in Ontario are charges applied to customers who maintain a connection to the grid primarily for backup purposes, such as those using on-site generation like generators or renewable energy. Standby charges apply to commercial and industrial customers, such as large factories. **These charges are paid directly by those customers, not all customers.**

These charges are designed to recover costs associated with providing a connection for backup power (for instance, if on-site generation is down for maintenance or temporary failure) and maintaining the distribution system.

Currently, standby rates are applied to 16 out of the 17 communities served by Entegrus Since the amalgamation in 2018 (and prior), standby rates did not apply to customers in St. Thomas.

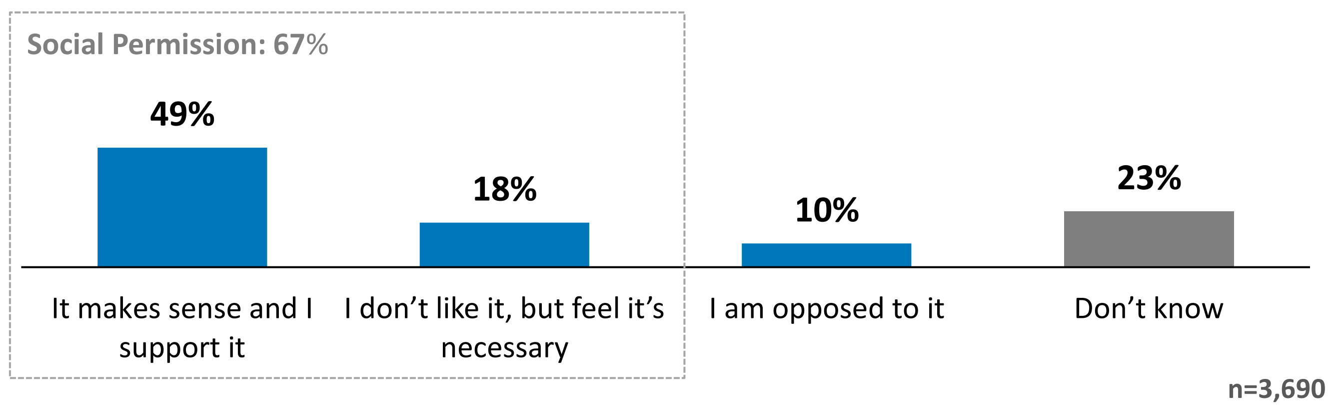
While these charges largely only apply to and are paid by commercial and industrial customers, Entegrus would like your feedback on whether standby rates should be extended to St. Thomas customers who have backup power connections, to be consistent with the rest of the communities served by Entegrus.

Standby Rates

Social permission on standby rates

Residential

Q Which of the following best describes how you feel about extending standby rates to customers in St. Thomas?



	Region				Bill Impact	
	Chatham	St. Thomas	Strathroy	Rest	Major Impact	No Major Impact
Support	52%	48%	53%	46%	43%	60%
Don't like it but necessary	17%	20%	15%	19%	20%	15%
Oppose	8%	12%	5%	11%	12%	6%
Don't know	23%	21%	27%	24%	25%	19%
Social Permission (Support + Necessary)	**69%**	**67%**	**69%**	**65%**	**63%**	**75%**

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Standby Rates

Social permission on standby rates

Residential

Q Which of the following best describes how you feel about extending standby rates to customers in St. Thomas?

		Consumption Quartiles				LEAP/OESP Qualification		
	Overall	Low	Medium-Low	Medium-High	High	Qualified	<$71k Not Qualified	>$71k Not Qualified
Support	49%	47%	51%	48%	50%	41%	54%	58%
Don’t like it but necessary	18%	19%	20%	18%	16%	21%	19%	16%
Oppose	10%	10%	9%	9%	11%	10%	8%	9%
Don’t know	23%	23%	20%	25%	23%	28%	19%	17%
Social Permission (Support + Necessary)	**67%**	**66%**	**71%**	**66%**	**66%**	**62%**	**73%**	**74%**

Residential Customers

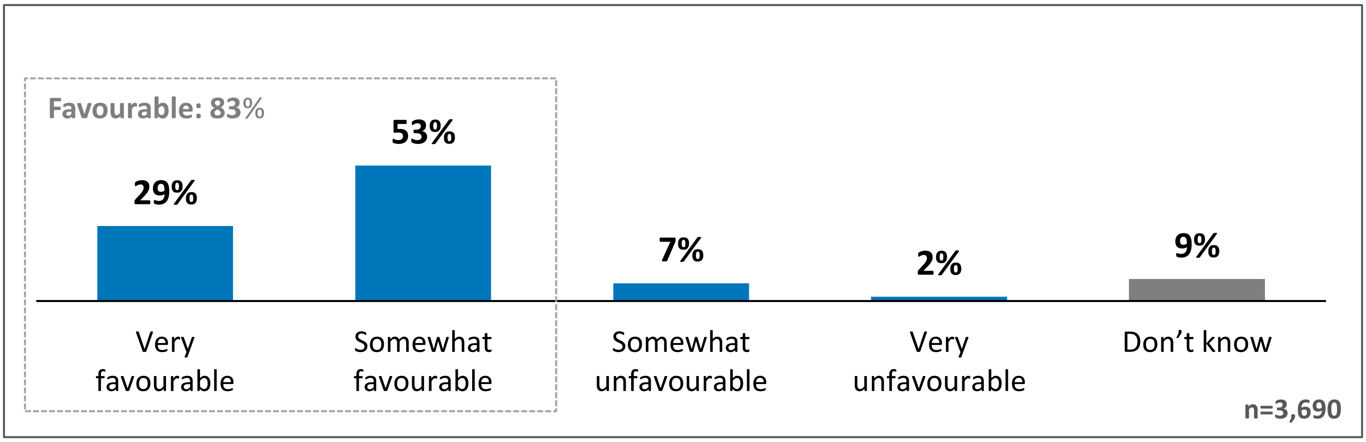
Workbook Diagnostics

Workbook Diagnostics

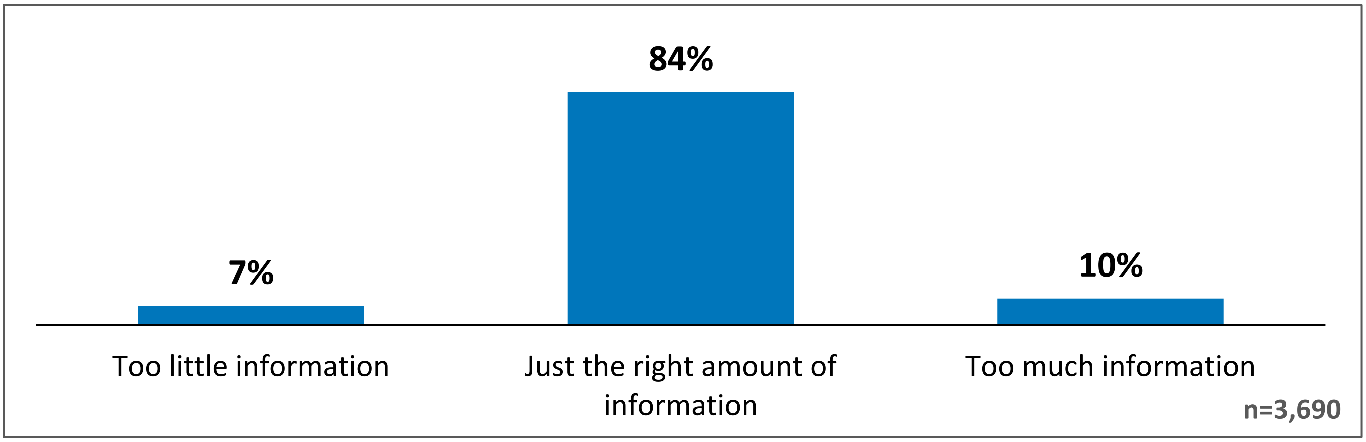
Favourability and amount of information

Residential

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Entegrus provided too much information, not enough, or just the right amount?



Workbook Diagnostics

Missing content from the engagement

Residential

Q Was there any content missing that you would have liked to have seen included in this customer engagement?

Responses	%
More information/details - general	2.4%
Transparency on operations, finances, management salaries	1.5%
Plans to reduce/lower customer costs	1.0%
Distrust in the engagement/rate increases are inevitable	0.7%
Renewable energy technology and investments	0.5%
Survey was too long/complicated	0.3%
Survey was educatonal/informative	0.3%
Better outage communication/information	0.2%
Reasons for outages/differences across regions	0.2%
Helping seniors/fixed-income individuals	0.2%
Environmental consideration	0.2%
More information on rate harmonization	0.2%
Concerns over impacts of the tariff war	0.1%
More information on vegetation management	0.1%
Appreciate being able to provide input	0.1%
Other	0.7%
None/Don’t know	91.3%

Note: Only responses >0.1% shown.

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Workbook Diagnostics

Remaining questions

Q Is there anything that you would still like answered?

Responses	%
Transparency in cost increases/cost breakdown	2.0%
Cost management and operational efficiency	0.8%
Grid modernization and future demand readiness	0.4%
Impact on seniors and low-income households	0.4%
Explanation for high delivery charges	0.3%
Information on green energy initiatives	0.2%
Severe weather concerns/hardening the system	0.2%
Rate harmonization and regional differences in costs	0.2%
Underground infrastructure upgrades	0.2%
EV and future demand planning	0.1%
Other	1.7%
None/Don't know	93.5%

Note: Only responses >0.1% shown.

Small Business Customers

Online Workbook Results

Field Dates

The **Small Business Online Survey** was sent to all GS<50 customers with an email address on file. Customers had an opportunity to complete the survey between **April 1st and April 30th, 2025**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the small business survey was sent to **2,307** customers from *engage@entegrus.com*. Reminder emails were sent on April 8th, April 16th, and April 24th 2025 to those who had not yet completed the survey.

Small Business Online Survey Completes

A total of **114** (unweighted) Entegrus small business customers completed the online survey.

Sample Weighting

The small business online survey sample was weighted to n=110 proportionately by consumption quartiles and region in order to be representative of the broader Entegrus customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values as some customers are missing region or consumption quartile information. Weights are calculated based off of all available information for a given customer.

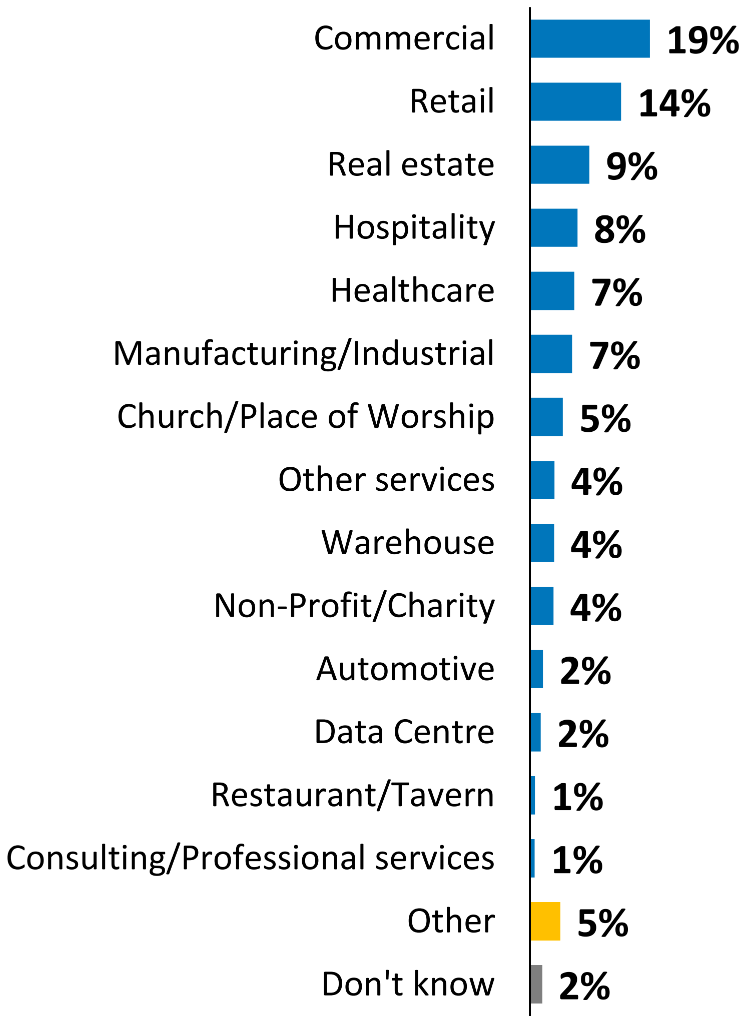
Region	Consumption Quartiles		Total
	Low-Medium	Medium-High	
Chatham	10 (13)	13 (17)	23 (30)
St. Thomas	14 (18)	22 (16)	36 (34)
Strathroy	6 (5)	5 (6)	11 (11)
Rest	23 (19)	20 (16)	44 (35)
Total	53 (55)	60 (55)	114 (110)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Firmographic Breakdown

Small Business

Q Business Sector



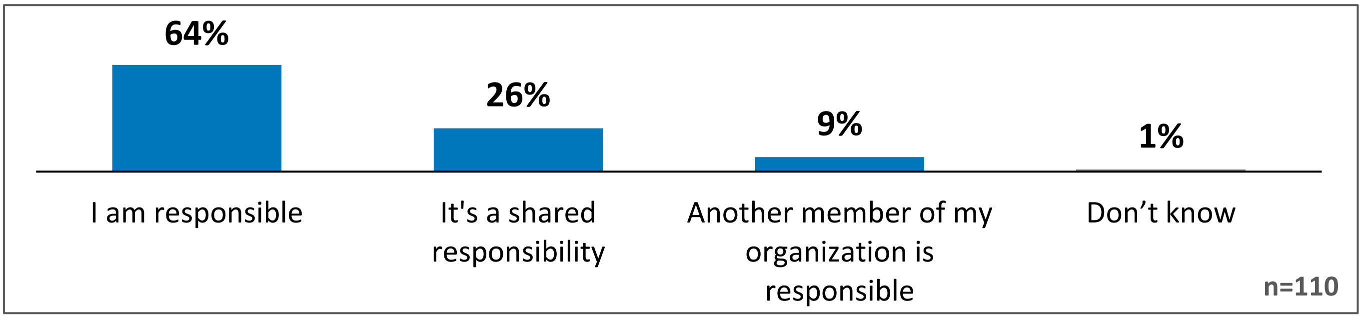
“Prefer not to say” (8%) not shown.

n=110

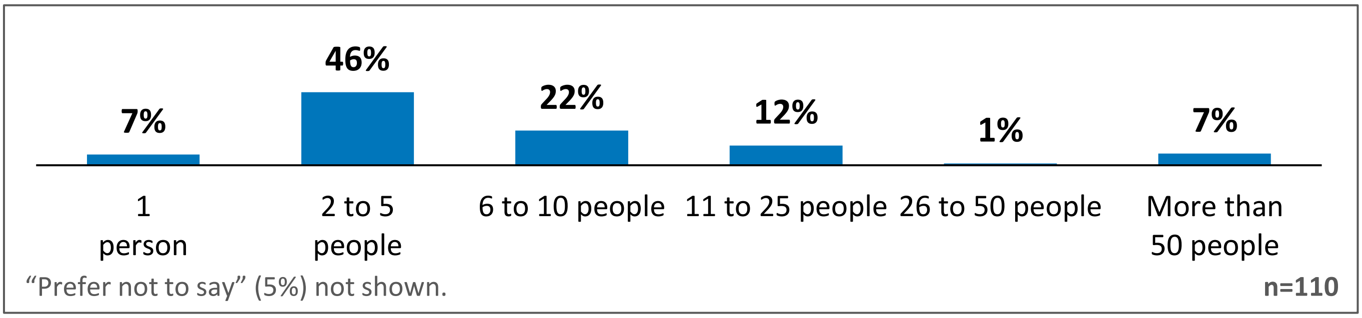
Firmographic Breakdown
Continued

Small Business

Q Bill Responsibility



Q Business Size



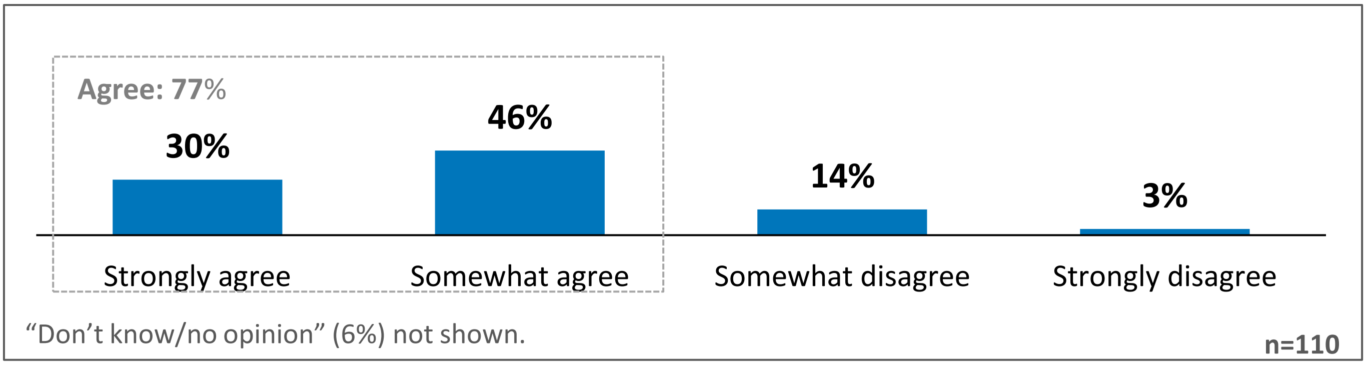
INNOVATIVE RESEARCH GROUP

Environmental Controls

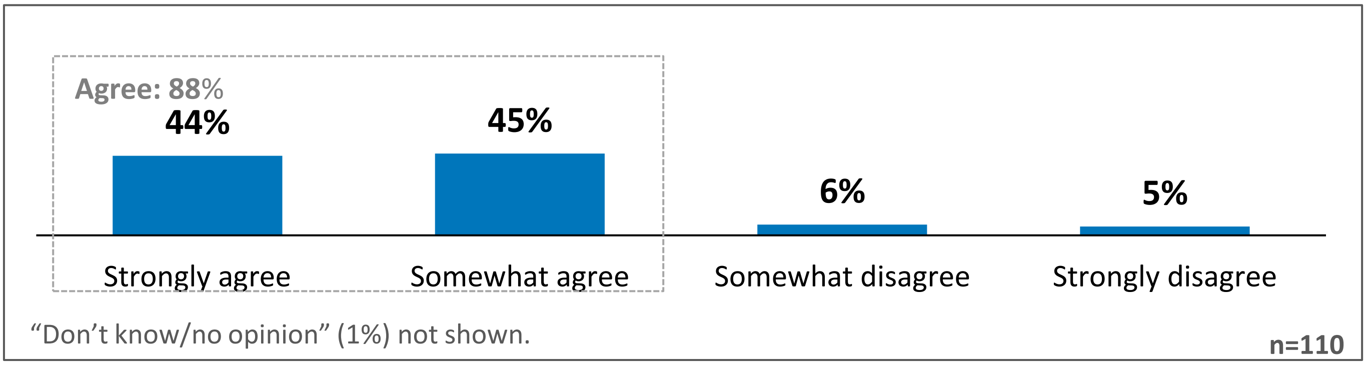
Small Business

To what extent do you agree or disagree with the following statements?

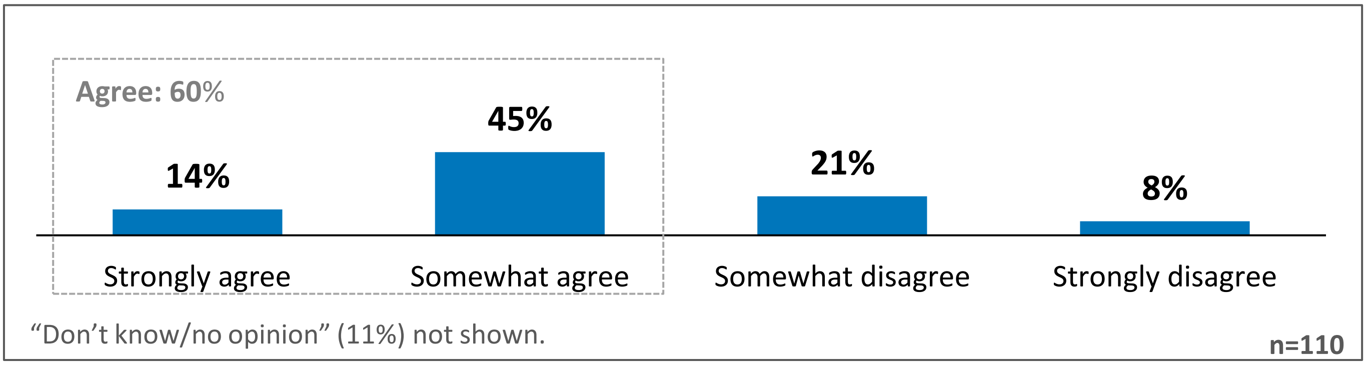
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



Q Customers are well served by the electricity system in Ontario.



Q Customers are protected with respect to the price we pay for electricity.



Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Welcome to Entegrus' customer engagement survey!

The purpose of this survey is to get your feedback on Entegrus' upcoming draft investment plan.

- **Who has been invited to participate?** All Entegrus customers will be invited to participate in this survey. It's important that we hear from a wide range of customers from across the region.
- **What is this survey about?** This survey is focused on key decisions that Entegrus needs to make before finalizing their investment plans.
- **Why participate?** Your electricity rates pay for this plan and Entegrus must demonstrate that customer feedback was incorporated into its plans.
- **How long will the survey take?** The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. The survey is best completed on a laptop or tablet.

Those who complete the survey will be invited to enter a draw to win one (1) of five (5) $500 cash prizes.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Entegrus to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Entegrus in any identifiable way.

INNOVATIVE RESEARCH GROUP

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Before we begin… a bit more about this survey!

Typically, every five years, local distributors like Entegrus are required to file an application with the Ontario Energy Board (OEB) to set rates.

However, as an outcome of the 2018 merger with St. Thomas Energy, Entegrus rates have increased at, or below, the rate of inflation since 2018.

Now, for the first time since the merger, Entegrus will be filing its next rate application that will cover the years 2026-2030.

In this process, Entegrus' rate application will be examined in detail and, again, Entegrus must demonstrate that customer needs and priorities were factored into this process.

Throughout 2024, nearly 2,000 Entegrus customers participated in surveys to aid in the development of Entegrus' draft plans.

Today, Entegrus is looking for your input to ensure that the plans they developed are, in fact, aligned with what customers want and expect.

Later this year, **Entegrus will present its proposed plans and input provided by customers to the OEB.**

You don't need to be an electricity expert to participate. This survey is focused on basic choices and provides the background information you need to answer the questions.

So, what are we going to talk about?

Today's survey will focus on two broad categories.

1. First, we need to ensure that we're all on the same page regarding Entegrus' role in the broader electricity system.
2. Second, you will be asked some questions about specific investment decisions that Entegrus needs to make to finalize their plans.

Familiarity & Experience

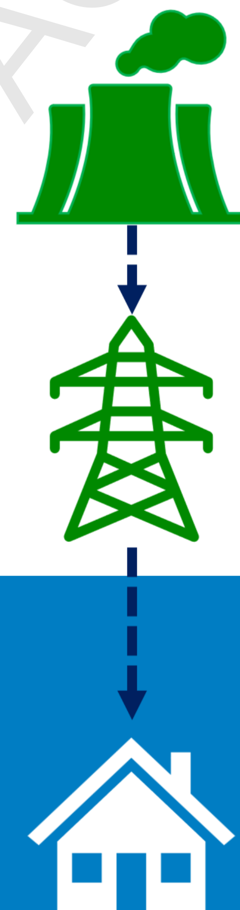
Entegrus' role in Ontario's electricity system

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

What is Entegrus' role in Ontario's electricity system?

Ontario's electricity system is made up of three key components: **generation**, **transmission** and **distribution**.



Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources. About half comes from nuclear power. The remainder comes from a mix of hydroelectric, natural gas, wind and solar. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity.

Transmission

How electricity travels across Ontario

Once electricity is generated, it must be transported to communities across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Most of this system is owned and operated by Hydro One.

Local Distribution

How electricity is delivered to you

Entegrus is responsible for the local distribution system, which takes electricity from transmission lines and brings it to your community.

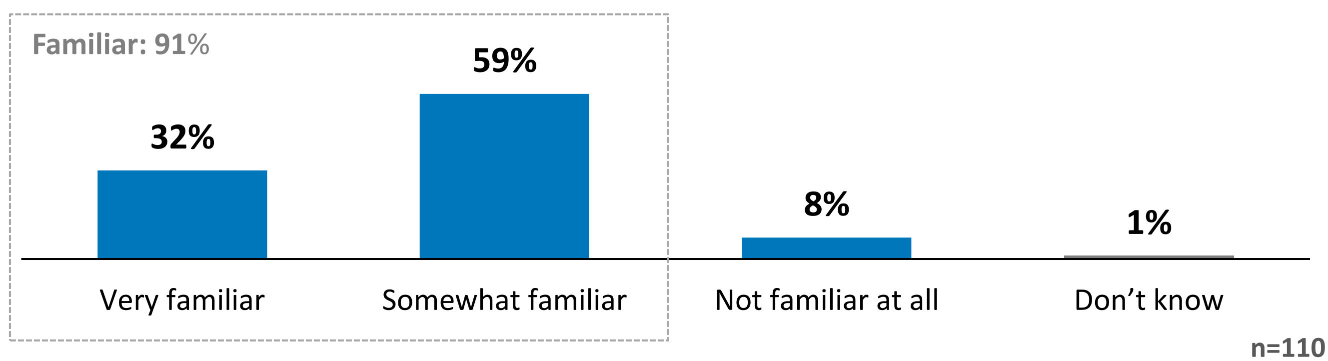
Entegrus builds and maintains power lines, transformers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Entegrus does <u>not</u> generate electricity or set electricity prices.

Familiarity & Experience

Familiarity with Entegrus' role in the system

Q How familiar are you with **Entegrus**, which operates the electricity distribution system in your community?



	Collapsed Consumption Quartiles		Bill Impact	
	Low Medium	Medium-High	Major Impact	No Major Impact*
Very familiar	34%	30%	39%	10%
Somewhat familiar	64%	55%	53%	82%
Not familiar at all	2%	13%	7%	9%
Don't know	--	2%	1%	--
Familiar (Very + Somewhat)	**98%**	**85%**	**91%**	**91%**

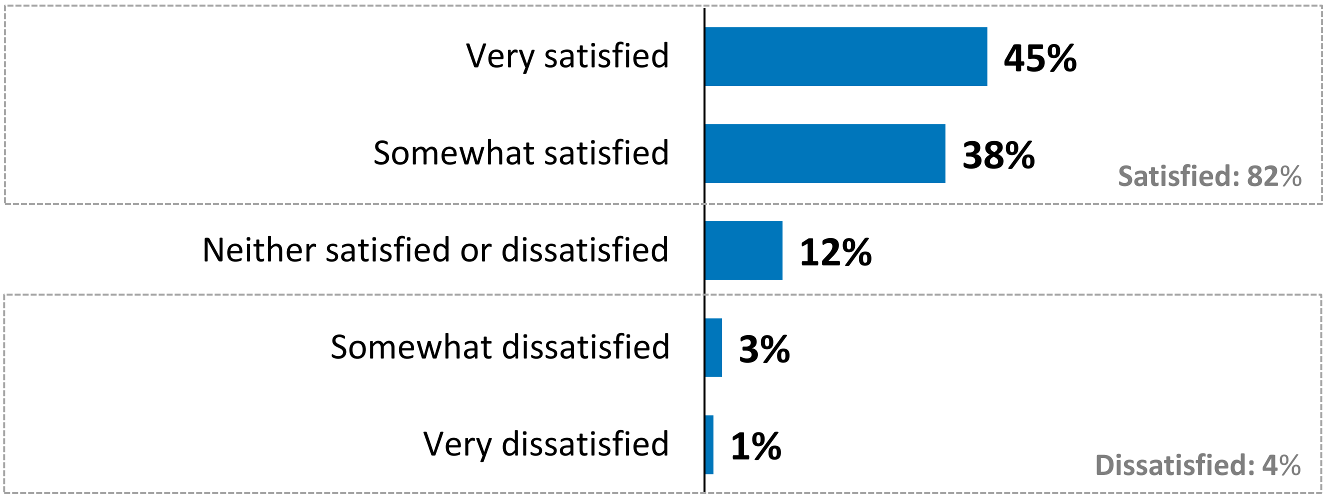
*__Note__: Small sample size (n=26); interpret results with caution

Familiarity & Experience

Overall satisfaction with Entegrus

Small Business

Q Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that you receive?



"Don't know" (1%) not shown.

n=110

	Collapsed Consumption Quartiles		Bill Impact	
	Low Medium	Medium-High	Major Impact	No Major Impact*
Very satisfied	54%	35%	46%	40%
Somewhat satisfied	33%	43%	40%	32%
Neither satisfied nor dissatisfied	7%	17%	9%	23%
Somewhat dissatisfied	5%	--	2%	5%
Very dissatisfied	--	3%	2%	--
Don't know	--	2%	1%	--
Satisfied (Very + Somewhat)	**87%**	**78%**	**86%**	**71%**
Dissatisfied (Very + Somewhat)	**5%**	**3%**	**4%**	**5%**

***Note**: Small sample size (n=26); interpret results with caution

Familiarity & Experience

More about Entegrus

Small Business

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

More about Entegrus

Entegrus owns and operates distribution systems **serving 17 communities in Southwestern Ontario**, stretching between Wheatley (to the west), St. Thomas (to the east), Parkhill (to the north) and Lake Erie (to the south).

- Most of the initial system expansion in the Entegrus communities occurred between 1950 and 1970**.** Some of the equipment in Entegrus' distribution system is more than 50 years old.
- Entegrus' service territory today is a product of multiple mergers and amalgamations dating back to the late-1990s – most recently the amalgamation with **St. Thomas Energy** in 2018.
- Today, Entegrus has operation centres in both Chatham and St. Thomas.

Familiarity & Experience

Portion of bill that goes to Entegrus

Small Business

Entegrus Main Version

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much of my electricity bill goes to Entegrus?

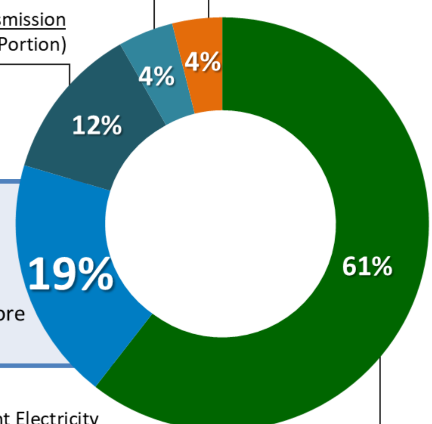
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.
- **For a typical small business customer, 19% of the total bill or about $62 goes to Entegrus each month.**
- The rest of your bill payment goes to power generation and transmission companies, taxes, and regulatory agencies.

Sample Entegrus Monthly Bill
(based on consumption of 2,000 kWh as of May 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 18.2 c/kWh	56.88
Mid-Peak (mid price) @ 12.2 c/kWh	43.92
Off-Peak (lowest price) @ 8.7 c/kWh	97.28
Delivery	116.38
Regulatory Charges	12.77
Total Electricity Charges	**$327.23**
HST	42.54
Ontario Electricity Rebate	(-$42.87)
Total Amount	**$326.91**



*IESO = Independent Electricity System Operator

The chart above is based on a total bill of $327.23 excluding the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 2,000 kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

Note: In the workbook, sample bills differed based on rate zone (Entegrus main or St.Thomas).

Familiarity & Experience

Portion of bill that goes to Entegrus

Small Business

St. Thomas Version

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much of my electricity bill goes to Entegrus?

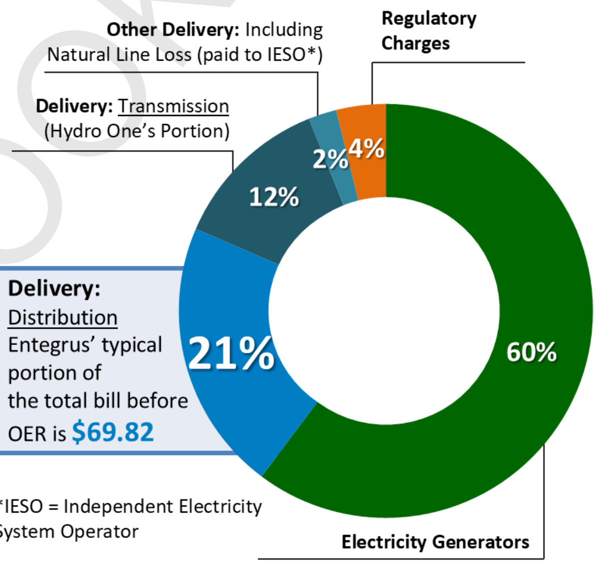
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.
- **For a typical small business customer, 21% of the total bill or about $70 goes to Entegrus each month.**
- The rest of your bill payment goes to power generation and transmission companies, taxes, and regulatory agencies.

Sample Entegrus Monthly Bill
(based on consumption of 2,000 kWh as of May 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 18.2 c/kWh	56.88
Mid-Peak (mid price) @ 12.2 c/kWh	43.92
Off-Peak (lowest price) @ 8.7 c/kWh	97.28
Delivery	117.97
Regulatory Charges	12.72
Total Electricity Charges	**$328.77**
HST	42.74
Ontario Electricity Rebate	(-$43.07)
Total Amount	**$328.45**



Delivery: Distribution
Entegrus' typical portion of the total bill before OER is **$69.82**

*IESO = Independent Electricity System Operator

The chart above is based on a total bill of $328.77 excluding the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 2,000 kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

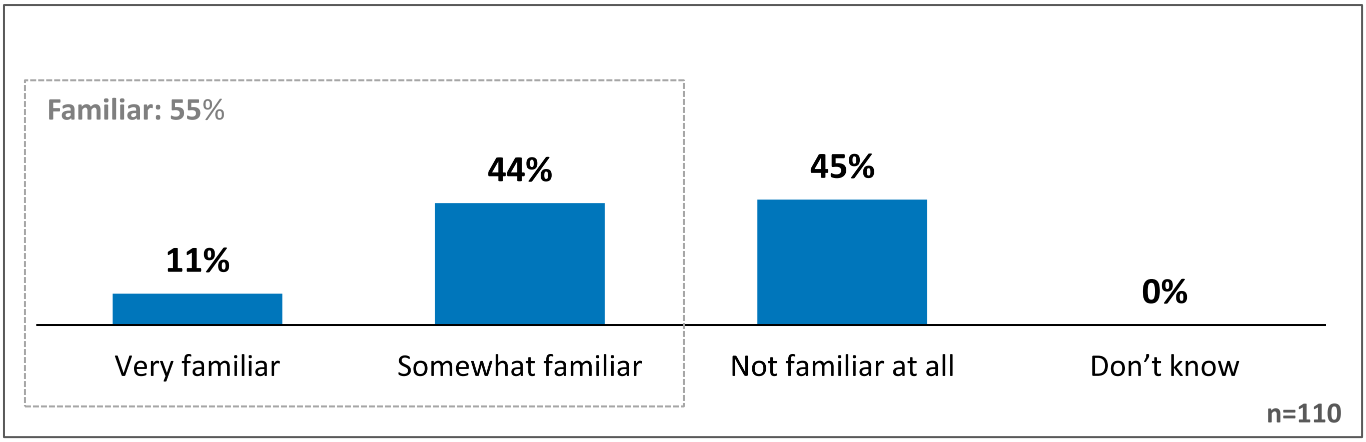
Note: In the workbook, sample bills differed based on rate zone (Entegrus main or St.Thomas).

Familiarity & Experience

Bill familiarity

Small Business

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Entegrus**?



	Collapsed Consumption Quartiles		Bill Impact	
	Low Medium	Medium-High	Major Impact	No Major Impact*
Very familiar	13%	9%	12%	9%
Somewhat familiar	40%	48%	44%	43%
Not familiar at all	46%	43%	44%	49%
Don’t know	--	--	--	--
Familiar (Very + Somewhat)	**54%**	**57%**	**56%**	**51%**

*__Note__: Small sample size (n=26); interpret results with caution

INNOVATIVE RESEARCH GROUP

Summary of Investment Plan

What Entegrus has heard so far

Small Business

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

What has Entegrus heard from customers so far?

In the summer of 2024, nearly 2,000 Entegrus customers participated in a series of surveys. These surveys included all types of customers, ranging from residential to commercial and industrial. Here's what Entegrus heard:

1. **Most customers prioritize affordability, followed closely by ensuring reliable service.**
2. **Customers largely support investment in maintaining current system reliability.**
3. **Many want Entegrus to proactively invest to ensure customers in higher growth areas do not experience a decline in reliability.**
4. **Customers would like to see Entegrus invest in new technologies when customer benefits are clear.**
5. **Many customers support improvements in customer service that make it easier to view and report outages.**

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Challenges facing Entegrus' grid

There are many challenges facing the electricity grid that Entegrus will seek to manage in its draft investment plan covering the years 2026-2030. The key challenges facing Entegrus' grid include:

- **Aging and deteriorating infrastructure, some of which is more than 50 years old.**
- **The increased frequency of severe weather in communities served by Entegrus.**
- **Rising costs related to inflation and supply chain disruptions.**
- **Increasing demand for electricity in communities served by Entegrus.**
- **The changing ways customers are using electricity and adoption of new technology.**
- **An increasing industry focus on cyber security and IT systems.**
- **An increasing industry focus on adoption of new technologies.**

In addition to the challenges above, Entegrus is also going to need to be responsive to the **ongoing threat of U.S. tariffs**. The threat of these tariffs make it increasingly difficult to forecast and plan, as costs could change and businesses could shift priorities, resulting in less than anticipated demand for electricity.

Regardless, Entegrus has prepared its 2026-2030 draft investment plan to address these challenges with the ultimate objective of being responsive to external pressures while providing safe and reliable electricity to communities at a reasonable cost.

Summary of Investment Plan

Objectives of the draft investment plan

Small Business

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

What is Entegrus' draft plan?

In addition to feedback received from customers, Entegrus has developed its draft plans based on information and input from internal engineering and technical experts who closely monitor the pressures on the distribution system, develop solutions to address these challenges, and recommend investments that inform its plans.

Below are some of the highlights of Entegrus' 2026-2030 draft plan.

1. **Manage rising costs and limiting potential rate increases.**
2. **Maintain current levels of reliability, while targeting improvements for customers experiencing poorer reliability than average.**
3. **Prepare the system to support community growth and respond to new customer requests.**
4. **Explore new technologies to make Entegrus' operations more efficient and offer clear customer benefits.**
5. **Offer customers new ways to view account information, track, and report outages in real-time.**
6. **Ensure that all 17 communities served by Entegrus pay the same for the service they receive.**
7. **Prepare the grid to be more resilient in the face of more frequent severe weather.**

Throughout the remainder of this survey, you will be asked to provide feedback that focuses on these key objectives – where there may be opportunities to do more or less than is currently planned.

But first, Entegrus will tell you about some of the efforts to manage rising costs.

Summary of Investment Plan

What Entegrus is doing to keep costs down

Small Business

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

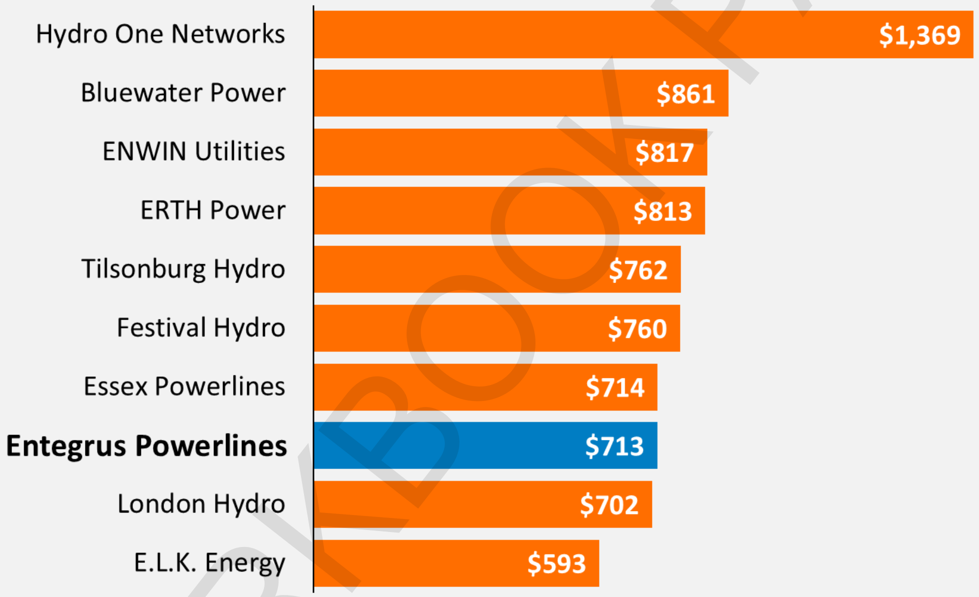
What is Entegrus doing to keep costs down?

According to the latest data published by the Ontario Energy Board, Entegrus is among the most efficient utilities in Southwestern Ontario, as measured by the total cost per customer.

Below is a regional comparison across Southwestern Ontario.

Southwestern Ontario Utility Comparison: Total Cost per Customer

Source: 2023 OEB Electricity Distributor Scorecard



In an effort to keep costs down, Entegrus is a member of the GridSmartCity Co-operative, an organization that brings together 15 Ontario electricity distributors to collaborate and share knowledge, skills and expertise – with some of the goals being increased efficiency and cost savings through economies of scale.

Cost saving benefits include negotiated group rates for services and group savings on the procurement of wood poles, cables, wires, and transformers.

Additionally, through its 2018 merger with St. Thomas Energy, Entegrus continues to see annual savings of approximately $1.7 million each year through shared operating, maintenance, and administrative costs.

Summary of Investment Plan

Cost of Entegrus' draft plan to customers

Small Business

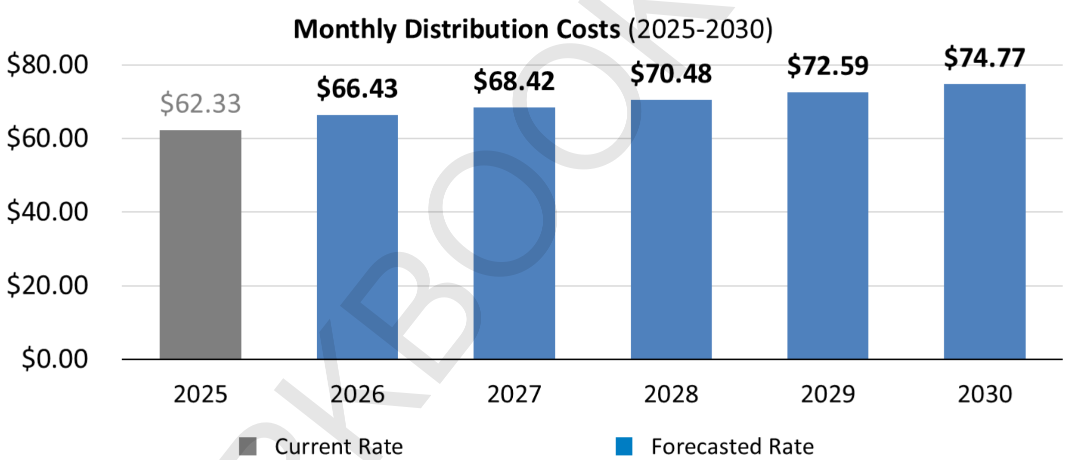
Entegrus Main Version

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much will Entegrus' draft plan cost me?

To achieve the outcomes outlined in Entegrus' draft plan, it is estimated that the typical **small business** customer would see the distribution portion of their electricity bill increase by **$12.44** from **$62.33 today (2025)** to a proposed rate of **$74.77 by 2030**.



These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical small business customer is assumed to use 2,000 kWh per month and enrolled under Time-of-Use Regulated Price Plan.

Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas).

Summary of Investment Plan

Cost of Entegrus' draft plan to customers

Small Business

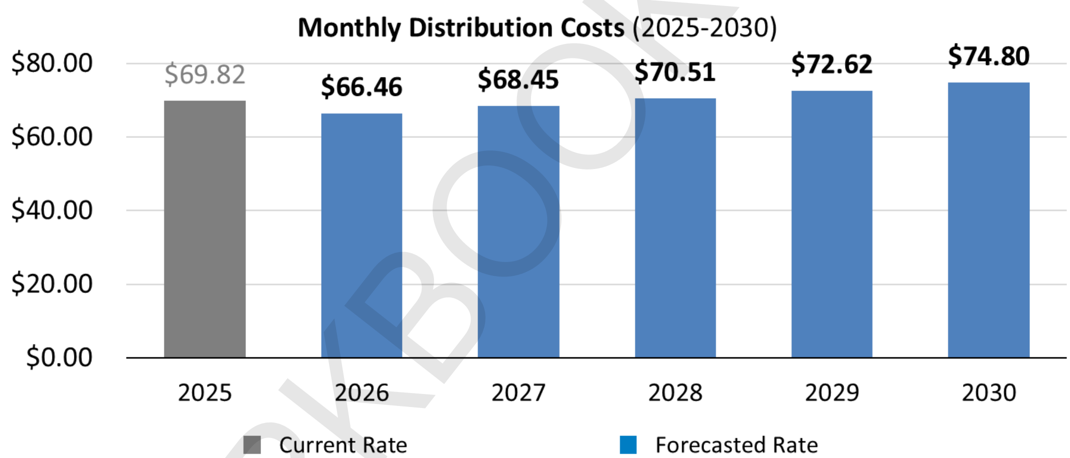
St. Thomas Version

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much will Entegrus' draft plan cost me?

To achieve the outcomes outlined in Entegrus' draft plan, it is estimated that the typical **small business** customer would see the distribution portion of their electricity bill increase by **$4.98** from **$69.82 today (2025)** to a proposed rate of **$74.80 by 2030**.



These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical small business customer is assumed to use 2,000 kWh per month and enrolled under Time-of-Use Regulated Price Plan.

Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas).

Summary of Investment Plan

Actual and forecasted budgets

Small Business

Entegrus Customer Engagement Survey

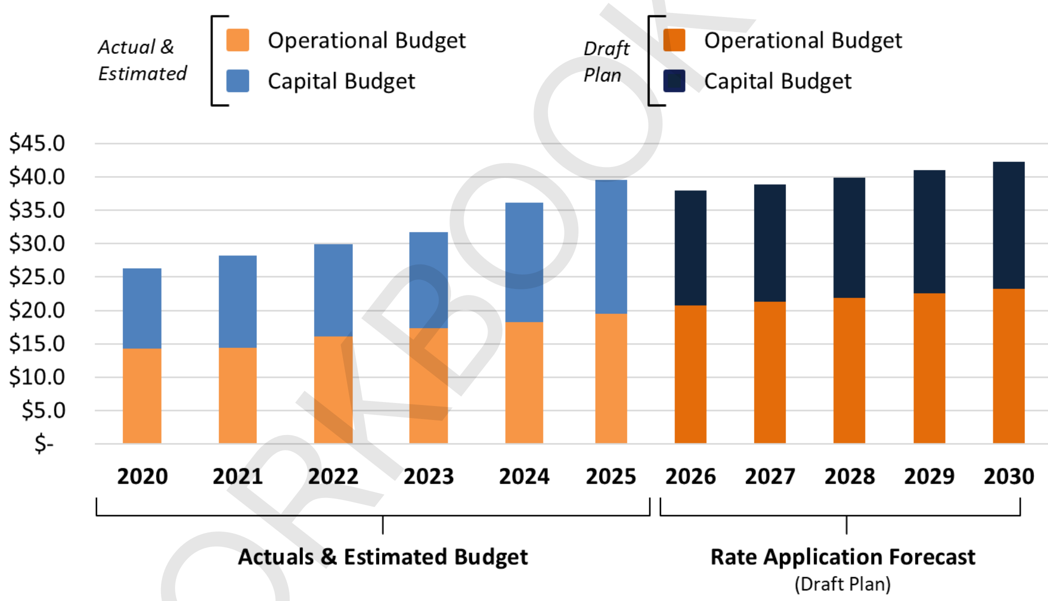
Planning for the Future: 2026-2030 Investment Plan

How does Entegrus plan future investments in the system?

Like most businesses, Entegrus manages both an operating budget and a capital budget.

- The **operating budget** covers recurring expenses, such as the maintenance of assets and tools, customer services, running all business systems and processes, as well as the cost of employees who ensure these activities are completed.
- The **capital budget** includes the costs to build the system, such as the overhead and underground infrastructure, computers and information systems, vehicles and facilities. These items, once purchased, provide long term benefits for many years to come.

Actual and Forecasted Budgets per year ($ millions)



The final budget for 2026-2030 will be adjusted to reflect customer feedback collected through this engagement and any necessary adjustments prior to filing with the OEB. The OEB and other stakeholders will complete an extensive review before rates are set for 2026-2030.

Before these plans can be finalized, Entegrus needs your feedback on the objectives discussed earlier.

Entegrus must demonstrate that their investment plans are directly responsive to customer needs and preferences.

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How do I make choices?

The remainder of this survey asks for your input on **4 key choices** that will affect the services you receive and the rates that you pay from 2026-2030.

- Each choice has a summary of the options that Entegrus is considering. In many cases, that includes options that would see Entegrus spend less or spend more than what is currently being proposed in the draft investment plan.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance.

Recall, Entegrus is entirely funded by the rates paid by its customers.

That means, the investments that are discussed in the subsequent pages are directly funded by customers.

Investment Trade-Offs

Targeted reliability investments

Small Business

Entegrus Customer Engagement Survey

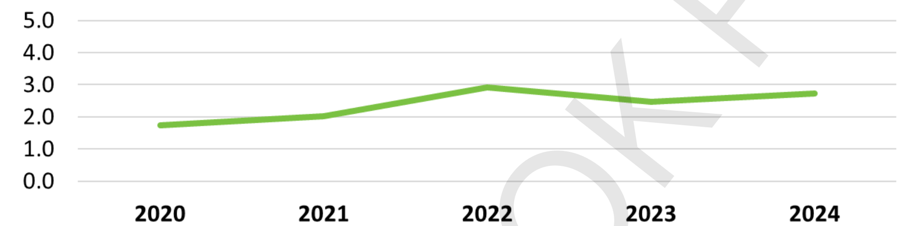
Planning for the Future: 2026-2030 Investment Plan

Choice 1 of 4: Targeted Reliability Investments

First, let's discuss the reliability of the electricity grid in your community.

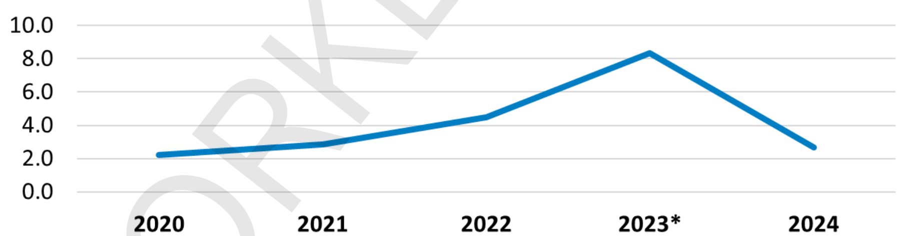
On average, between 2020 and 2024, the typical Entegrus customer has experienced **about 2.4 outages per year**.

Average number of outages (outages per customer)



Over the same period, the **average duration of an outage has been about 4 hours**. Meaning, when the power does go out, Entegrus is typically able to restore power in about four hours.

Average Outage Duration (outage length in hours per customer)



*** In 2023, Entegrus communities experienced four significant storms, resulting in an above average length of time that customers were without power.**

It's important to keep in mind that these are system averages, and that your actual experience may be different. Customers experience different levels of reliability, depending on where they live, the design of the system, and the condition of the equipment supplying them.

Investment Trade-Offs

Targeted reliability investments

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 1 of 4: Targeted Reliability Improvements

In the current draft plan, Entegrus' planners have identified a series of targeted investments to improve reliability for those customers that experience poorer reliability than average. This includes automated switches that allow Entegrus to automatically reroute power during outages, in part, reducing the length of time customers are without power.

Entegrus could accelerate spending in this area, resulting in reliability improvements for more customers who have historically experienced poorer reliability than average.

Or Entegrus could reduce spending in this area, resulting in reliability improvements for fewer customers who have historically experienced poorer reliability than average.

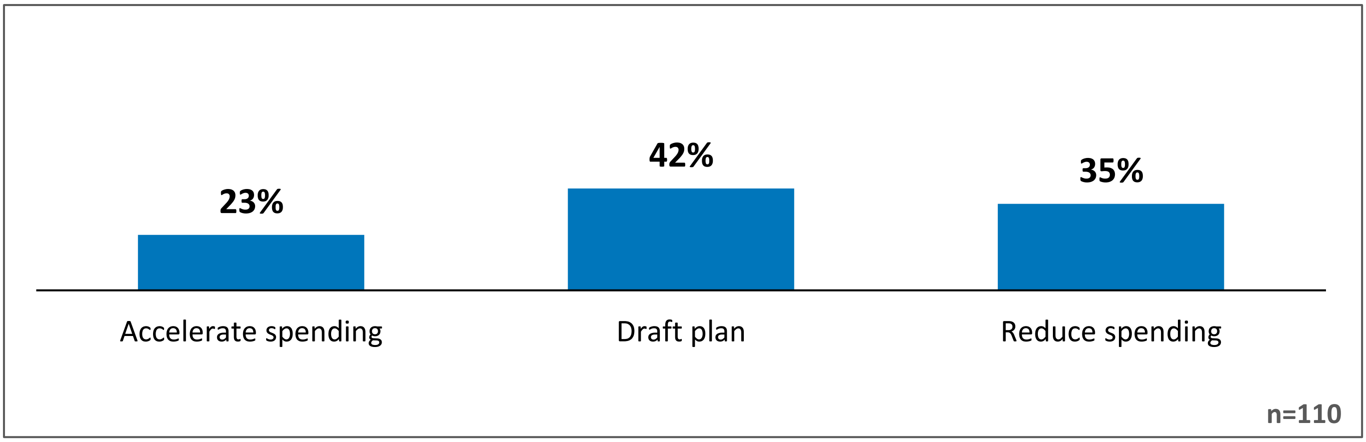
Investment Trade-Offs

Targeted reliability investments

Small Business

Q Which of the following options do you prefer?

Option	Expected Outcome(s)
Accelerate spending ***$0.45** more on monthly bill by 2030*	• Make further targeted investments to improve reliability for more customers who experience significantly poorer reliability than average.
Draft plan *Within proposed rate increase*	• Make targeted investments to improve reliability for some customers who experience significantly poorer reliability than average.
Reduce spending ***$0.23** less on monthly bill by 2030*	• Reduce targeted investments to improve reliability for customers experiencing significantly poorer reliability than average.



	Collapsed Consumption Quartiles		Bill Impact	
	Low Medium	Medium-High	Major Impact	No Major Impact*
Accelerate spending	19%	27%	24%	20%
Draft plan	41%	43%	39%	50%
Reduce spending	41%	30%	37%	30%

***Note**: Small sample size (n=26); interpret results with caution

Investment Trade-Offs

Targeted reliability investments

Small Business

Q Additional Feedback (Optional)

Verbatim Responses (95% either said 'Don't know' or 'No comment/No response')
"Any plan must include continuous preventative maintenance to minimize power disruptions, in addition to spending to make the system more reliable. Capital costs for acquiring the St. Thomas grid should never be passed on to your customers outside St. Thomas."
"I am surprised the plan doesn't have a greater percentage on Capital improvements that will ultimately lower the operational budget annually. I would vote for more capital investment upfront."
"I know you are not directly responsible for the rates, however, many people cannot afford any type of increase. Rates have already increased by 100% over the past 5-7 years."
"The accelerated spending should be on old equipment before it fails. More money does not mean more bonus for management. We having our own business is hard to get more money out of our customers. There is other suppliers who can do it cheaper but in this case we have one."
"The delivery fee for "low density" should be based on location from major lines that stretch from town to town...not based on population density. I live on [REDACTED], where the line must go from Wheatley to Blenheim, and I am still considered low."
"These are similar questions you asked on the last survey. Has nothing been done since then?"

Investment Trade-Offs

Preparing for community growth

Small Business

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 2 of 4: Preparing for Community Growth

As more customers start getting electric vehicles, solar panels, or just generally continue to use electricity differently, more and more equipment will need to be upgraded to accommodate these changes. If demand increases quicker than expected in a specific community, this could strain the system and lead to equipment failing more frequently.

Transformers are a critical piece of equipment that help accommodate this changing electricity usage. They are located throughout your community and are usually mounted on top of wooden poles.

As a rule of thumb, the larger the transformer, the more electricity it can serve to the homes and businesses on the other end of the wire. Today, the smaller transformers that have historically served residential homes are increasingly struggling to keep up with demand.

In the current draft plan, Entegrus will upgrade transformers reactively as they fail and install bigger transformers for new homes being constructed.

Alternatively, Entegrus could introduce a new program to proactively upgrade transformers that are most at risk of overloading and therefore failure. Proactive replacement can:

a) Help ensure that customers have access to enough electricity when they need it

b) Reduce the risk of need for reactive replacement – and reducing outage durations – when equipment does fail.

That said, proactive replacement does <u>not</u> necessarily reduce the current risk of outages. The benefit is more about preparing the grid for the future and minimizing future reliability risks.

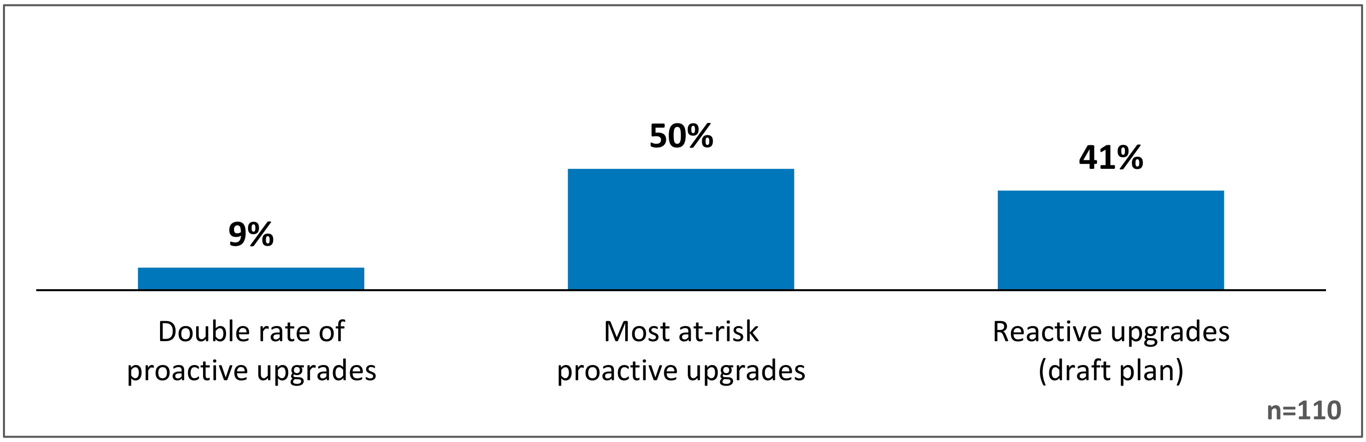
Investment Trade-Offs

Preparing for community growth

Small Business

Q Which of the following options do you prefer?

Option	**Expected Outcome(s)**
Double rate of proactive upgrades ***$0.90 more** on monthly bill by 2030*	• Double the rate of proactive upgrades of most at-risk transformers • Further reduce the risk of outages due to transformer failures
Most at-risk proactive upgrades ***$0.45 more** on monthly bill by 2030*	• Proactively upgrade most at-risk transformers • Potentially reduce the risk of outages due to transformer failures
Reactive upgrades (draft plan) *Within proposed rate increase*	• Maximize the useful life of current transformers • Potential for higher levels of unplanned outages due to transformer failures



Investment Trade-Offs
Preparing for community growth

Q Which of the following options do you prefer?

		Collapsed Consumption Quartiles		Bill Impact	
	Overall	Low Medium	Medium-High	Major Impact	No Major Impact*
Double rate of proactive upgrades	9%	12%	7%	11%	3%
Most at-risk proactive upgrades	50%	48%	52%	46%	61%
Reactive upgrades (draft plan)	41%	40%	41%	43%	36%

***Note**: Small sample size (n=26); interpret results with caution

Investment Trade-Offs

Preparing for community growth

Small Business

Q Additional Feedback (Optional)

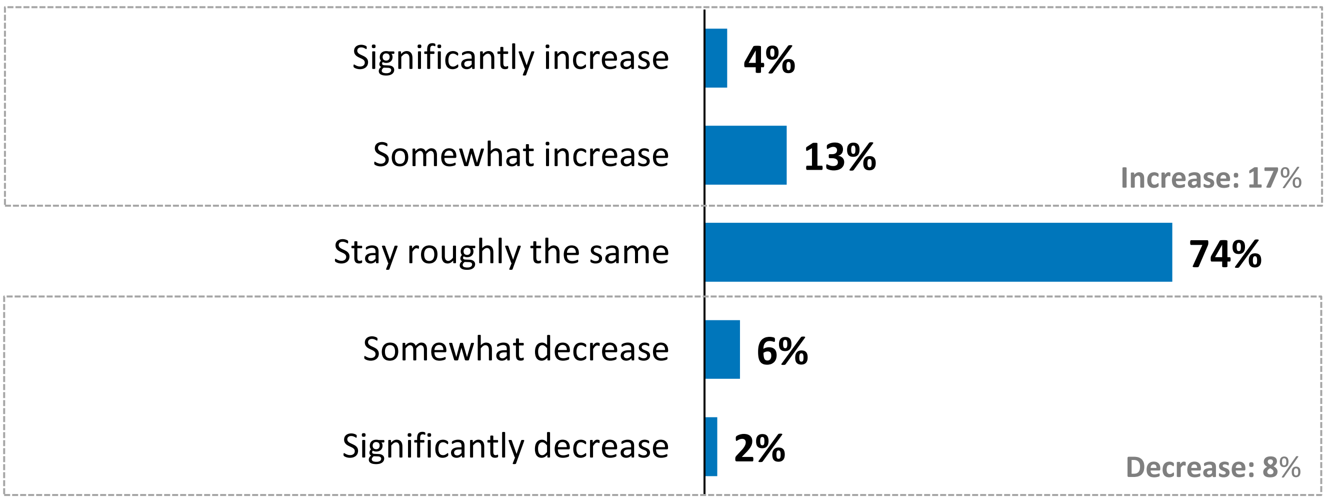
Verbatim Responses (98% either said 'Don't know' or 'No comment/No response')
"Any plan should include local solar arrays and battery backup to reduce the effect of power disruptions and generate electricity in times of instability. Experience has shown that Florida subdivisions with large rooftop solar arrays were able to slough off major power disruptions caused by weather events. It also prevents overloads to the system caused by rerouting power."
"Capital upgrades on transformers is a good investment."
"I don't believe the increased usage is coming in this budget."

Investment Trade-Offs

Preparing for community growth

Small Business

Q In the next five years, do you anticipate your organization's electricity usage will increase, decrease, or stay roughly the same?



"Don't know" (2%) not shown. n=110

	Collapsed Consumption Quartiles		Bill Impact	
	Low Medium	Medium-High	Major Impact	No Major Impact*
Significantly increase	4%	3%	4%	3%
Somewhat increase	10%	16%	14%	8%
Stay roughly the same	70%	77%	74%	72%
Somewhat decrease	9%	2%	6%	5%
Significantly decrease	2%	1%	1%	5%
Don't know	5%	--	1%	7%
Increase (Very + Somewhat)	**14%**	**19%**	**18%**	**11%**
Decrease (Very + Somewhat)	**11%**	**4%**	**7%**	**11%**

***Note**: Small sample size (n=26); interpret results with caution

Investment Trade-Offs
Tree and vegetation trimming

Small Business

Choice 3 of 4: Tree and Vegetation Trimming

The third investment Entegrus would like your feedback on is on emerging technology to better monitor Entegrus' distribution system.

Entegrus serves 17 communities and has thousands of trees across its service territory and in proximity to its lines.

On a regular basis, Entegrus must ensure those trees remain a safe distance from electrical equipment like poles and wires. Currently, on a multi-year cycle, Entegrus goes community-by-community to trim trees and other vegetation. In a typical year, outages due to tree contacts account for approximately 7-19% of all customer outages.

In previous surveys, many customers said that they would support Entegrus piloting new technology that would use satellites to build a 3D model of vegetation and lines across the communities served by Entegrus. This technology would allow for more precise planning to minimize the magnitude of trimming required.

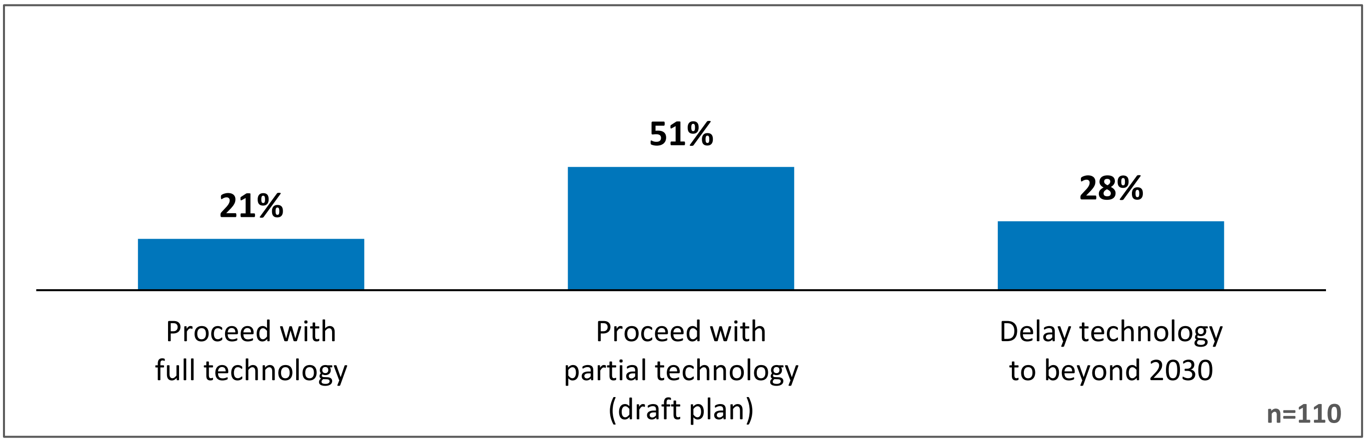
As planning has progressed, Entegrus has identified an opportunity to expand this pilot to even further minimize tree contacts and reduce potential delays during large infrastructure projects. This would include augmenting the satellite modeling with more frequent and targeted ground-based scans, getting into more difficult to reach areas.

Currently, the draft plan includes piloting the satellite scans, however, Entegrus would like to hear if you would like them to do more or less. To keep costs down, Entegrus could continue with its current time-based approach to tree trimming and vegetation management.

Investment Trade-Offs
Tree and vegetation trimming

Q Which of the following options do you prefer?

Option	**Expected Outcome(s)**
Proceed with full technology ***$0.30*** *more on monthly bill by 2030*	• Allow targeted tree trimming and scanning of harder to reach areas in Entegrus' service territory, not completed with partial technology approach • May further reduce the number of outages caused by tree contacts than with partial technology
Proceed with partial technology (draft plan) *Within proposed rate increase*	• Allow for more targeted tree and vegetation trimming than the typical, manual approach • May reduce the number of outages caused by tree contacts
Delay technology to beyond 2030 ***$0.70*** *less on monthly bill by 2030*	• Continue with the current approach to tree and vegetation trimming • Unchanged likelihood of outages caused by tree contacts



Investment Trade-Offs

Tree and vegetation trimming

Q Which of the following options do you prefer?

	Overall	Collapsed Consumption Quartiles: Low Medium	Collapsed Consumption Quartiles: Medium-High	Bill Impact: Major Impact	Bill Impact: No Major Impact*
Proceed with full technology	21%	23%	20%	21%	22%
Proceed with partial technology (draft plan)	51%	48%	53%	47%	64%
Delay technology to beyond 2030	28%	29%	27%	33%	14%

*__Note__: Small sample size (n=26); interpret results with caution

Investment Trade-Offs

Tree and vegetation trimming

Small Business

Q Additional Feedback (Optional)

Verbatim Responses (99% either said 'Don't know' or 'No comment/No response')
"Traditionally, wires are broken by ice, wind or branches. This is more problematic in rural areas where there are fewer lines to reroute power. This is why solar array substations in rural areas will provide more assistance and reliability. Where necessary, property owners should be held accountable for tree trimming, or Entegrus can do it and bill them."

Investment Trade-Offs

Mobile application upgrades

Small Business

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 4 of 4: Mobile Application Upgrades

The fourth investment Entegrus would like your feedback on is on a mobile application.

Again, in earlier research, many customers expressed interest in expanded customer service offerings, specifically an app that includes **access to My Account (the Entegrus online customer account portal)**, **an outage map** and the **ability to report outages**.

In response to this feedback, Entegrus' draft plan includes investment to support the launch of a mobile application that provides these features. While this investment is responsive to customer feedback, Entegrus would like to confirm that customers would like them to proceed, knowing the full cost of this investment.

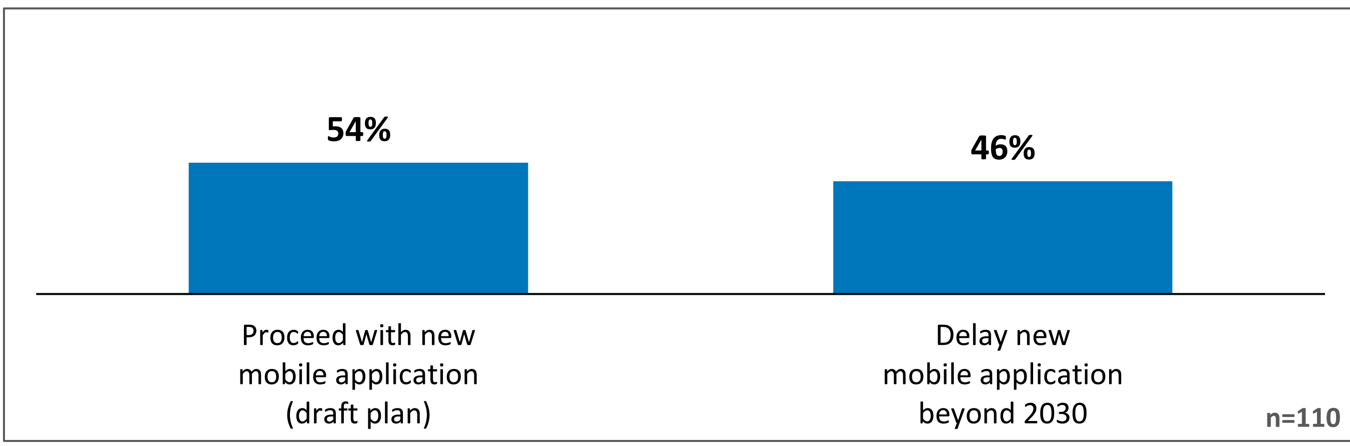
Investment Trade-Offs

Mobile application upgrades

Small Business

Q Which of the following options do you prefer?

Option	Expected Outcome(s)
Proceed with new mobile application (draft plan) *Within proposed rate increase*	• Allow customers the ability to access MyAccount, an outage map, and report outages online through a mobile application.
Delay new mobile application beyond 2030 ***$0.40** less on monthly bill by 2030*	• Continue with Entegrus' existing customer service offerings without proceeding with a new mobile application.



	Collapsed Consumption Quartiles		Bill Impact	
	Low Medium	Medium-High	Major Impact	No Major Impact*
Proceed with new mobile application (draft plan)	56%	51%	56%	47%
Delay new mobile application beyond 2030	44%	49%	44%	53%

*__Note__: Small sample size (n=26); interpret results with caution

Investment Trade-Offs

Mobile application upgrades

Q Additional Feedback (Optional)

Verbatim Responses (98% either said 'Don't know' or 'No comment/No response')
"As long as it can be done in a cost-effective way."
"Boomers are still not all techno geeks. Keep some customer service contact by human contact directly for some years to come."
"We each experience financial restrictions in poor economic times. It makes no sense to spend money on non-essentials until the grid is brought up to the new standards. Given a choice, spend the money on the grid. Keep the webpage updated with any issues, and they can consult your website, a better use of money."

Investment Trade-Offs

Finalizing Choices

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choices Calculator

Throughout this survey, you have been asked about 4 key choices from that could impact your rates. Below is a summary of your choices.

At the bottom of this page, you will find the total rate impact of your choices.

Please review your answers and change your responses if you desire, and your potential rate impact will be re-calculated. You can adjust your choices until you reach the best balance for you.

Investment Trade-Offs
Finalizing Choices

Small Business Customer Bill Impact Change and Magnitude of Bill Impact

Range of Impacts (Mean)
-$1.33 to +$1.65

About the "Range of Impacts"

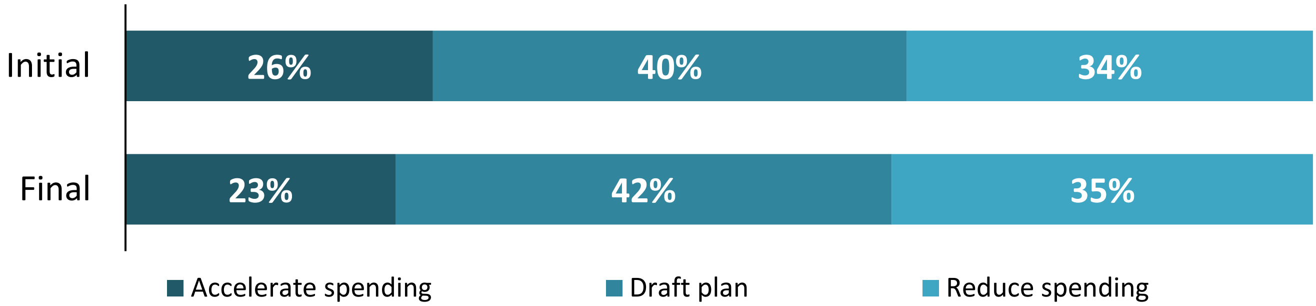
The "Range of Impacts" signifies the highest and lowest possible range of bill impacts above and beyond the Draft Plan. For instance, if a customer, where possible, were to select the biggest increase for each choice, their bill impact would result in **$1.65 more** per month by 2030 when compared to the draft plan. If they were to select the biggest decrease for each choice, it would result in **$1.33** less per month by 2030 when compared to the draft plan.

Investment Trade-Offs

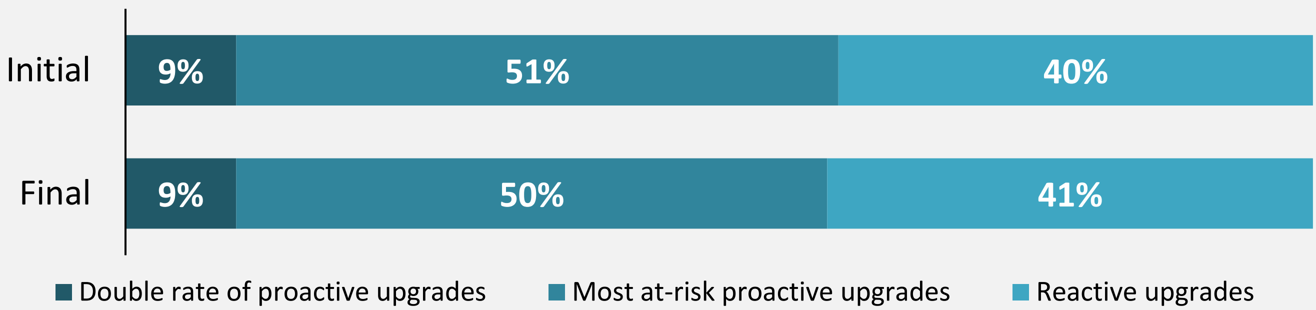
Finalizing Choices

Small Business

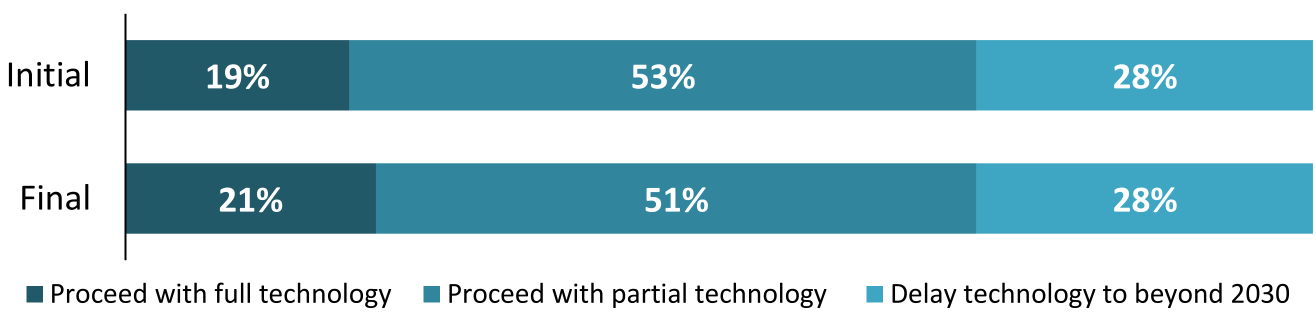
Targeted Reliability Improvements



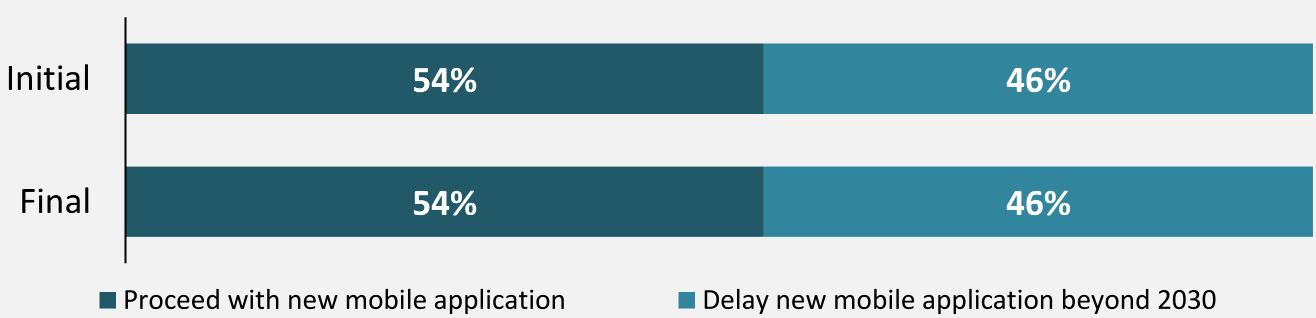
Preparing for Community Growth



Tree and Vegetation Trimming



Mobile Application Upgrades



Investment Trade-Offs

Overall evaluation of the plan

Small Business

Entegrus Main Version

Entegrus Customer Engagement Survey

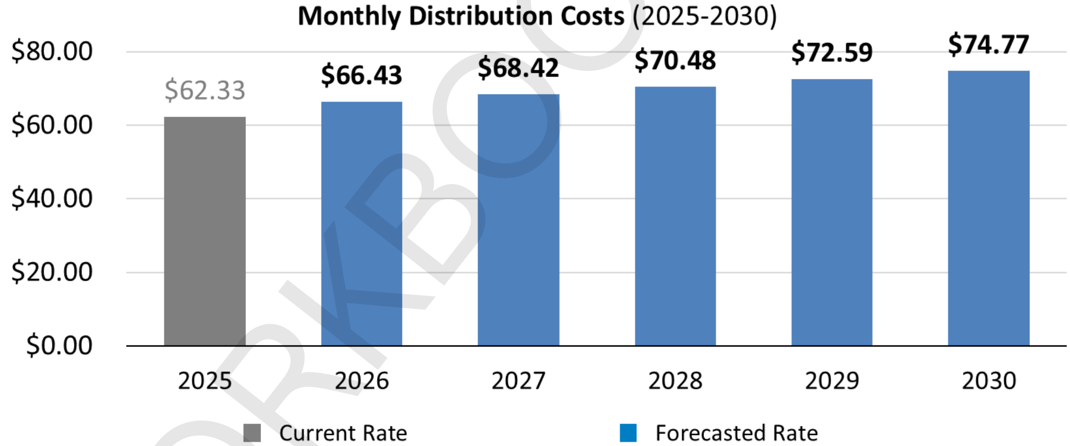
Planning for the Future: 2026-2030 Investment Plan

Assessing Entegrus' draft 2026-2030 plan

Entegrus has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Entegrus would like to know how you feel about the overall draft plan.

It is estimated that the typical **small business** customer would see the distribution portion of their electricity bill increase by **$12.44** from **$62.33 today (2025)** to a proposed rate of **$74.77 by 2030**.

Monthly Distribution Costs (2025-2030)



These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical small business customer is assumed to use 2,000 kWh per month and enrolled under Time-of-Use Regulated Price Plan.

Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas).

Investment Trade-Offs

Overall evaluation of the plan

Small Business

St. Thomas Version

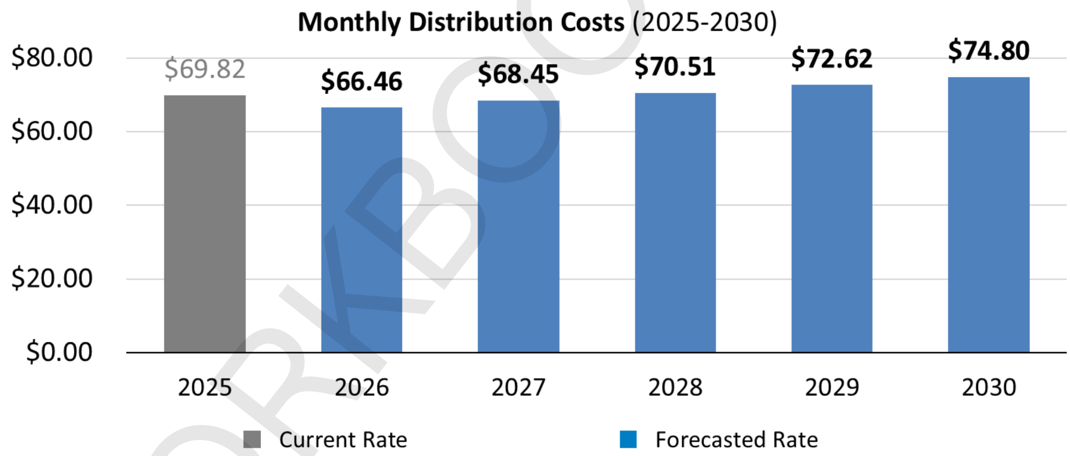
Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Assessing Entegrus' draft 2026-2030 plan

Entegrus has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Entegrus would like to know how you feel about the overall draft plan.

It is estimated that the typical **small business** customer would see the distribution portion of their electricity bill increase by **$4.98** from **$69.82 today (2025)** to a proposed rate of **$74.80 by 2030**.



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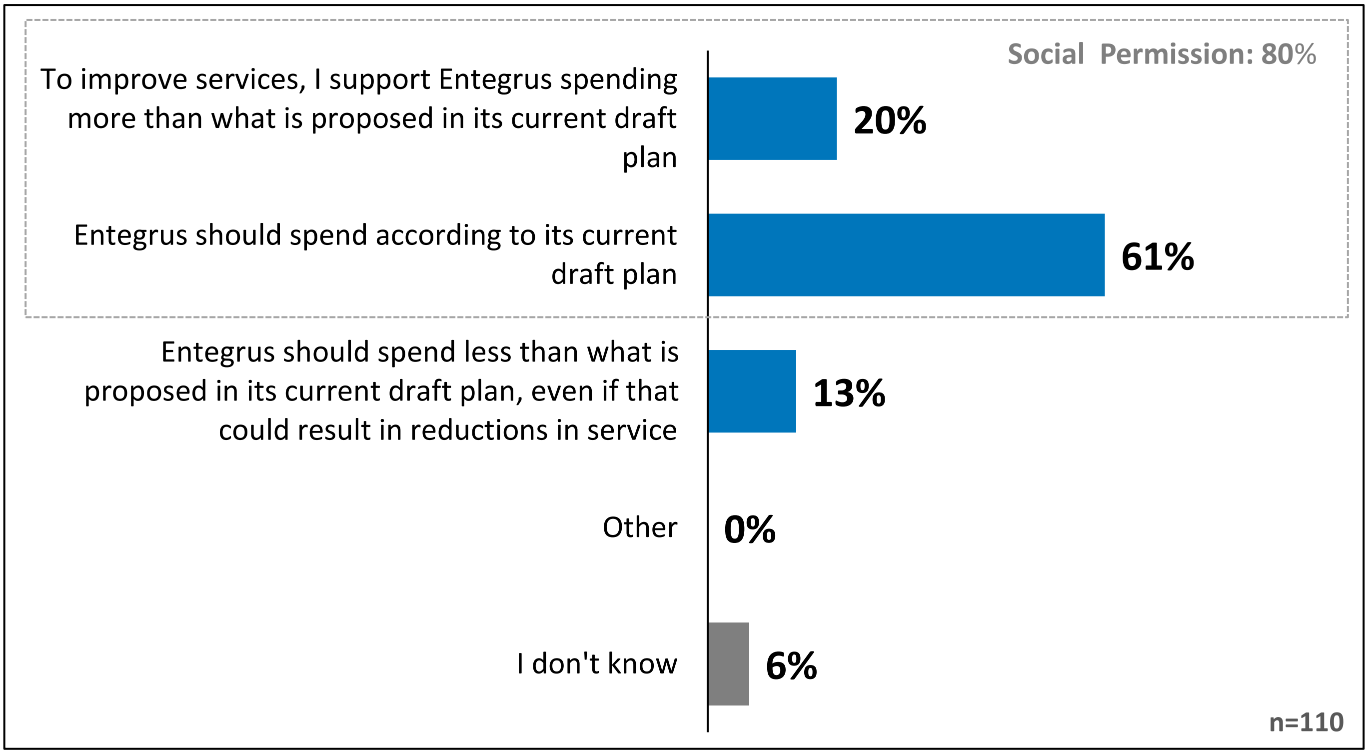
Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas).

Investment Trade-Offs

Overall evaluation of the plan

Small Business

Q Considering what you have learned about Entegrus' 2026–2030 draft plan, which of the following best represents your point of view?



	Collapsed Consumption Quartiles		Bill Impact	
	Low Medium	Medium-High	Major Impact	No Major Impact*
Spend more	13%	26%	18%	27%
Spend according to plan	62%	59%	63%	54%
Spend less	19%	7%	14%	11%
Other	--	--	--	--
I don't know	5%	7%	6%	9%
Social Permission	**75%**	**86%**	**80%**	**80%**

***Note**: Small sample size (n=26); interpret results with caution

Investment Trade-Offs

Final comments on the draft plan

Small Business

Q Do you have any final comments regarding Entegrus' draft plan for 2026–2030 and the proposed rate increase?

Verbatim Responses (89% either said 'Don't know' or 'No comment/No response')
"A small increase is worth more efficiency and reliability."
"Entegrus should also be considering the cost of upper management salaries. Seems that costs always increase for consumers and front-line workers get the added workload, but management gets the biggest wage increases."
"I hope the rate would be increased."
"I think it's time to examine how much these companies & their upper management earns (wages, bonuses etc), and how heavy they are in their management positions, excess spending. Cutting the fat in all these areas, I'm sure, would make all these accelerated, costly plans way more feasible!"
"Increase Capital expenditures with the goal to lower annual operating expenses."
"Instead of providing a survey slanted toward getting approval to increase costs, why not ask about whether the public and small business supports the monopoly at all? The industry should be opened up and competition let in. If the service is so great at Entegrus then the public will choose it, not be forced to use it. Small businesses don't have the luxury of paying huge wages, pensions and benefits, and then just passing on the cost to consumers that are required to pay it."
"Instead of tying the improvement of services to spending, the focus should be on increasing efficiency and cutting waste, therefore both increasing service quality and reducing cost."
"It has gotten very expensive in the last couple years to just run a household. Any increases are hard to budget. Canadians are taxed to death, and we are not all able to make ends meet."
"Just hoping no big increases."
"Reliability and cost-effective operation are more important than a flashy app. Reducing future expenses by building solar arrays and battery storage systems makes better financial sense than unnecessary expenses. Bring farmers in on the benefits with shared rooftop arrays on farm buildings in exchange for allowing them a fair percentage based additional income from helping ensure power stability."
"Support all recommendations to upgrade and provide enhanced reliability."
"We have more than enough energy here in Ontario. Our rates are too high now with all the resources we have."
"With the state of the current economy Entegrus needs to make wise choices as folks are having a hard time and given the tariffs now being imposed things are gong to get tougher. My wish is that no one has services cut off because they can't afford to pay their bill."

Rate Harmonization

Impact of rate harmonization

Small Business

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Rate Harmonization

A key principle for rates in Ontario is that similar customers should pay the same cost for similar service, regardless of where they are located within a utility service area. As a result of the 2018 amalgamation between Entegrus and St. Thomas Energy, this is not currently the case for all Entegrus customers.

Rate harmonization means bringing two sets of distribution rates into one harmonized rate so that all Entegrus customers in the same rate class pay the same for electricity distribution.

Since merging in 2018, there have been two different sets of rates – one set of rates for the 16 legacy Entegrus communities and one set of rates for St. Thomas.

How will it impact me?

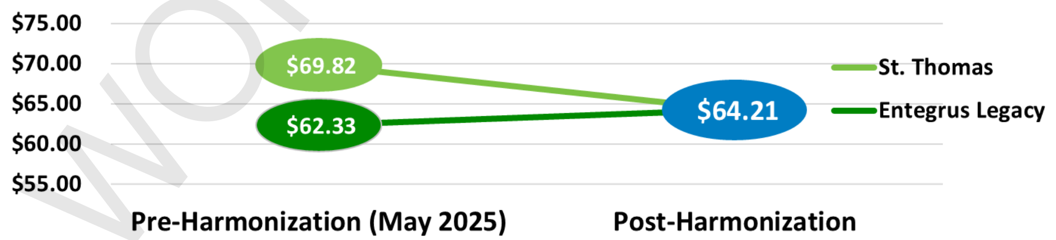
Starting in 2026, Entegrus is planning to harmonize rates for all 17 communities. This means that some customers would have a small increase on their bill while others will see a small decrease. **This change will represent less than 1% of the typical total bill.**

Before proceeding, Entegrus would like your feedback on this proposed change.

The chart below shows the impact of rate harmonization on customer rates.

Rate Harmonization Impact on Distribution Rates

Illustrative 2025 Rate Harmonization



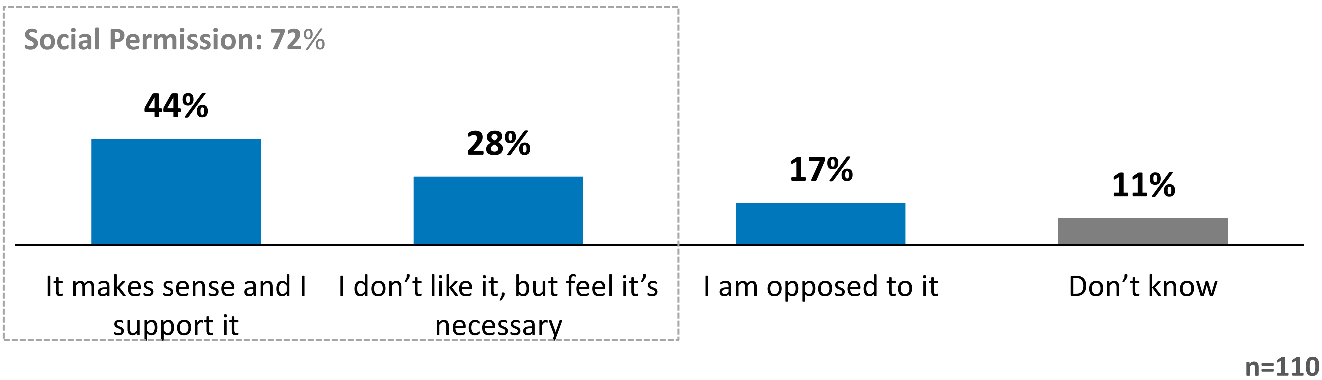
These illustrative estimates are calculated without the 2026 rate increase associated with the draft plan discussed throughout this survey and are subject to customer feedback and regulatory approval.

Rate Harmonization

Social permission on rate harmonization

Small Business

Q Which of the following best describes how you feel about rate harmonization?



	Collapsed Consumption Quartiles		Bill Impact	
	Low Medium	Medium-High	Major Impact	No Major Impact*
Support	41%	46%	40%	55%
Don't like it but necessary	27%	29%	31%	19%
Oppose	17%	18%	20%	9%
Don't know	15%	7%	9%	17%
Social Permission (Support + Necessary)	**68%**	**75%**	**71%**	**74%**

*Note: Small sample size (n=26); interpret results with caution

Standby Rates

Impact of standby rates

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Standby Rates

Standby rates in Ontario are charges applied to customers who maintain a connection to the grid primarily for backup purposes, such as those using on-site generation like generators or renewable energy. Standby charges apply to commercial and industrial customers, such as large factories. **These charges are paid directly by those customers, not all customers.**

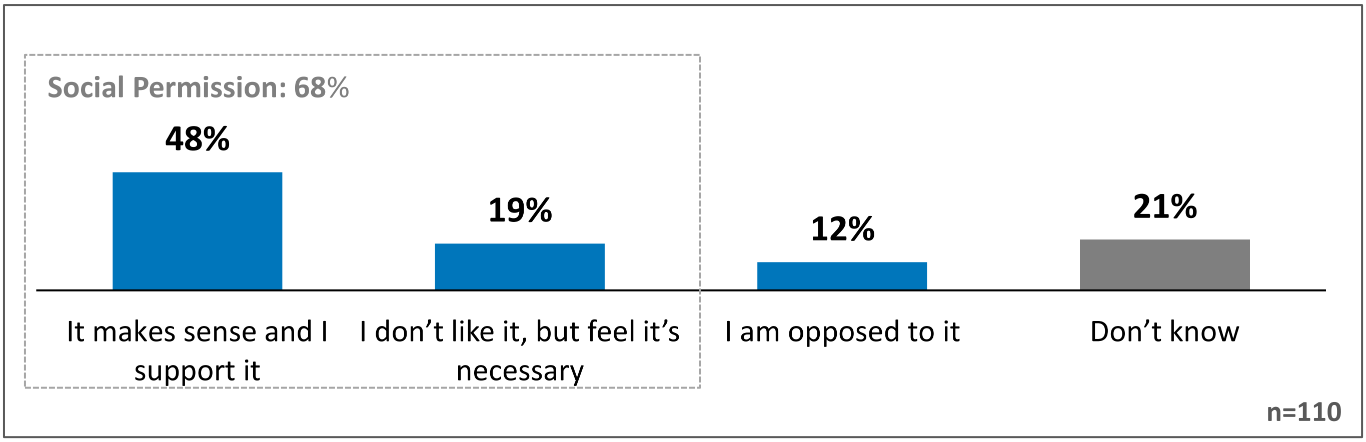
These charges are designed to recover costs associated with providing a connection for backup power (for instance, if on-site generation is down for maintenance or temporary failure) and maintaining the distribution system.

Currently, standby rates are applied to 16 out of the 17 communities served by Entegrus Since the amalgamation in 2018 (and prior), standby rates did not apply to customers in St. Thomas.

While these charges largely only apply to and are paid by commercial and industrial customers, Entegrus would like your feedback on whether standby rates should be extended to St. Thomas customers who have backup power connections, to be consistent with the rest of the communities served by Entegrus.

Standby Rates
Social permission on standby rates

Q Which of the following best describes how you feel about extending standby rates to customers in St. Thomas?



	Collapsed Consumption Quartiles		Bill Impact	
	Low Medium	Medium-High	Major Impact	No Major Impact*
Support	42%	55%	46%	57%
Don't like it but necessary	24%	15%	22%	11%
Oppose	13%	10%	12%	11%
Don't know	22%	20%	21%	21%
Social Permission (Support + Necessary)	**65%**	**70%**	**68%**	**67%**

*__Note__: Small sample size (n=26); interpret results with caution

Small Business Customers

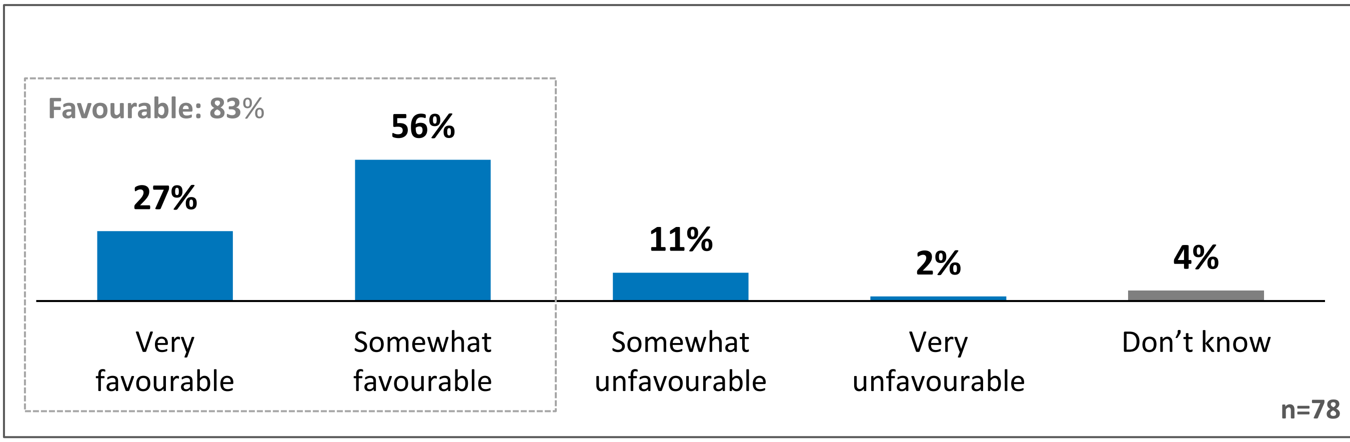
Workbook Diagnostics

Workbook Diagnostics

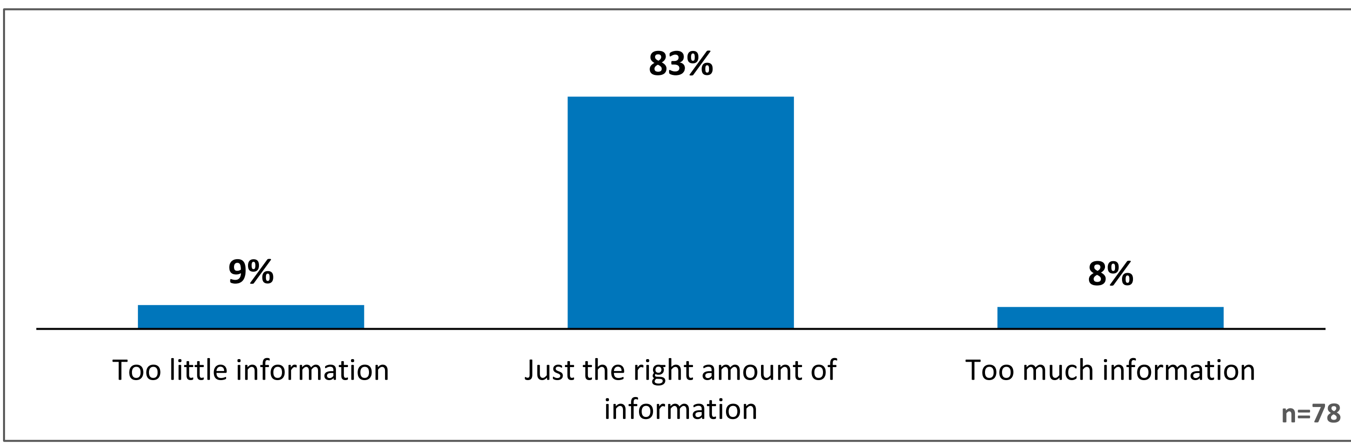
Favourability and amount of information

Small Business

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Entegrus provided too much information, not enough, or just the right amount?



Workbook Diagnostics

Missing content from the engagement

Small Business

Q Was there any content missing that you would have liked to have seen included in this customer engagement?

Verbatim Responses (90% either said ‘Don’t know’ or ‘None’)
“I didn't see any information on line losses resulting from distribution and the benefits being paid back to local generators (like solar) on your system.”
“I would like your company to disclose the pay increases to the administration and make sure that those salaries are in line with the market. I feel that services like this are taken advantage of by corporate greed.”
“It is hard not to be skeptical of information provided by the company who has an agenda.”
“Less leading questions.”
“More info on the human element of customer service might have proved useful many of our congregation are not technologically inclined.”
“The amount of money upper management are to earn by 2030.”
“There is no designation for zero number of people besides myself working at my location. It is used primarily as a residential living space. Entegrus designated my property as commercial in Aug 2019, even though it is zoned institutional.”
“Your question about standby rates concerns me. I believe in a user pay system. Having to pay for power one may use eventually makes no sense. Rather, one should pay for power used by their system if their system goes down. I also believe that if your company starts charging standby rates it will discourage the development of solar arrays with battery packs. As long as a solar producer agrees to provide power at the same price as your regular production rates then both can benefit. Charging standby rates until their system goes down will cause them to tell you to go away rather than ensuring greater reliability.”

Workbook Diagnostics

Remaining questions

Small Business

Q Is there anything that you would still like answered?

Verbatim Responses (93% either said 'Don't know' or 'None')
"Based on your information, it seems financially more advantageous to become a producer to earn a larger portion of the pie. With the help of farmer solar arrays with battery storage, your company can become a producer while increasing reliability for the grid. It requires a change of perspective from a provider to an energy cooperative company."
"Why does it take a week and a half to turn water on for a business when Entegrus drives by my business 3-4 times a day?"
"Why so much cost when no power is being used our vacation time?"
"Why was nothing done to "fix" whatever was wrong the numerous times "it" caused a fuse one your poles at the corner of [REDACTED] to "blow"?"
"Would like to know who controls the actual rates of electricity."

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Commercial & Industrial/Large Use Customers

Online Workbook Results

Field Dates

The **Commercial & Industrial/Large Use Online Survey** was sent to all GS>50 and large use customers with an email address on file. Customers had an opportunity to complete the survey between **April 1st and May 6th, 2025**.

Each customer received a unique URL that could be linked back to their average monthly demand, region, and rate class.

In total, the commercial & industrial/large use survey was sent to **274** customers from *engage@entegrus.com*. Reminder emails were sent on April 8th, April 16th, April 24th, and April 29th, 2025 to those who had not yet completed the survey.

Commercial & Industrial/Large Use Online Survey Completes

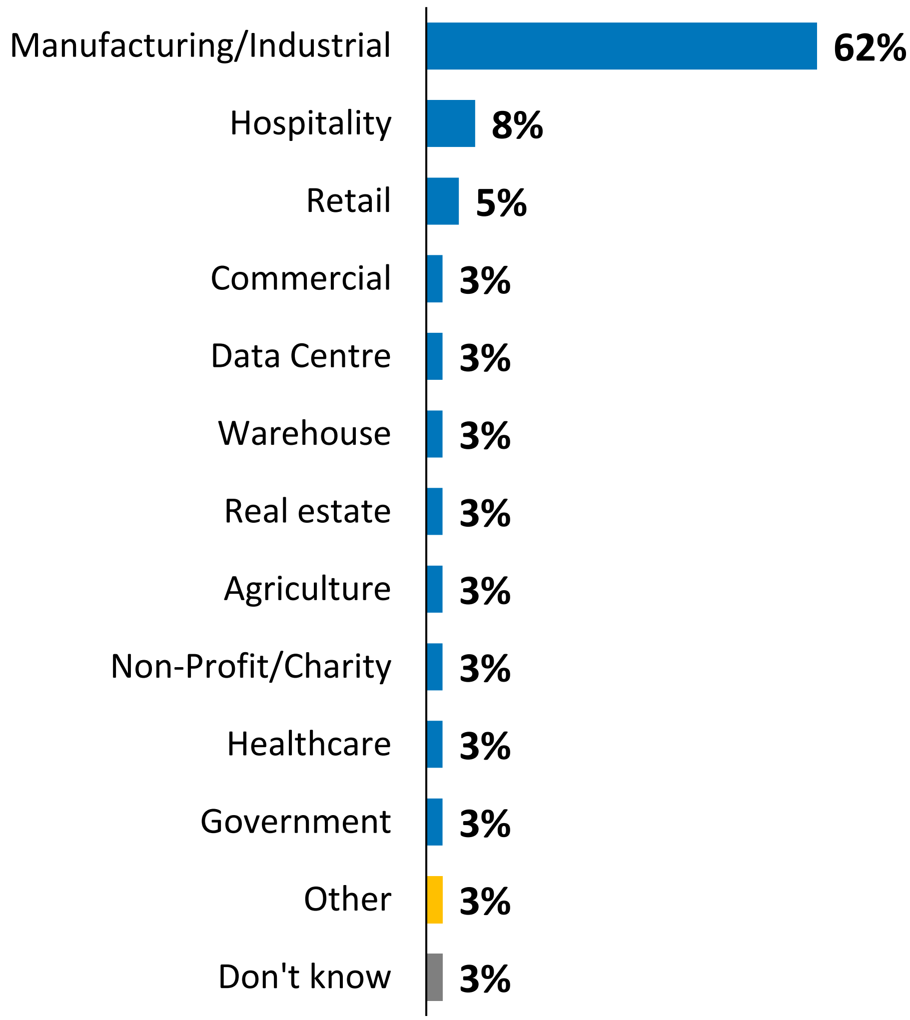
A total of **39** (unweighted) Entegrus commercial & industrial (GS>50) customers completed the online survey. No Large Use customers completed the online survey.

Sample Weighting

Due to the small sample size (n=39), the Commercial & Industrial results are not weighted. Results should be interpreted as directional only.

Firmographic Breakdown

Q Business Sector



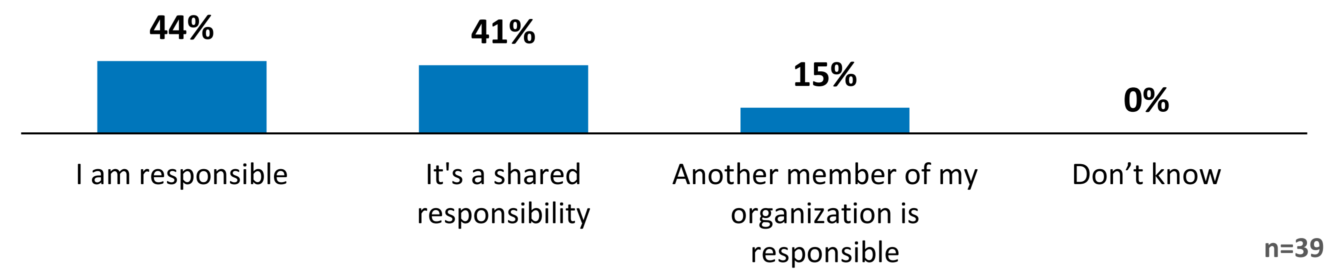
“Prefer not to say” (0%) not shown.

n=39

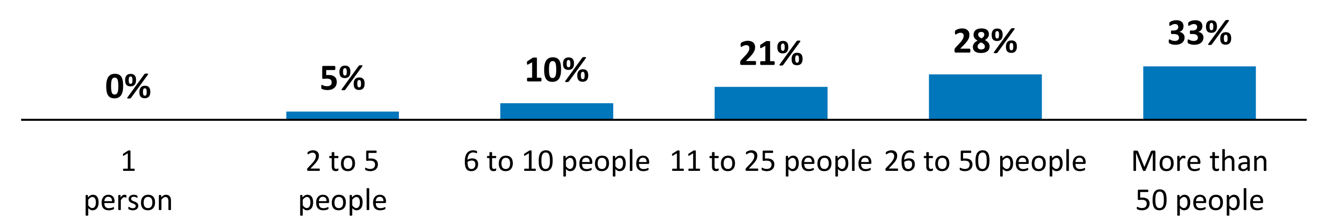
Firmographic Breakdown
Continued

Commercial & Industrial

Q Bill Responsibility



Q Business Size

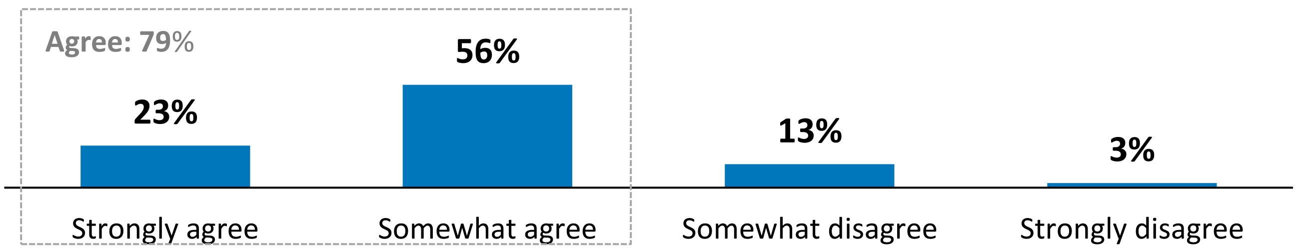


"Prefer not to say" (3%) not shown.

Environmental Controls

To what extent do you agree or disagree with the following statements?

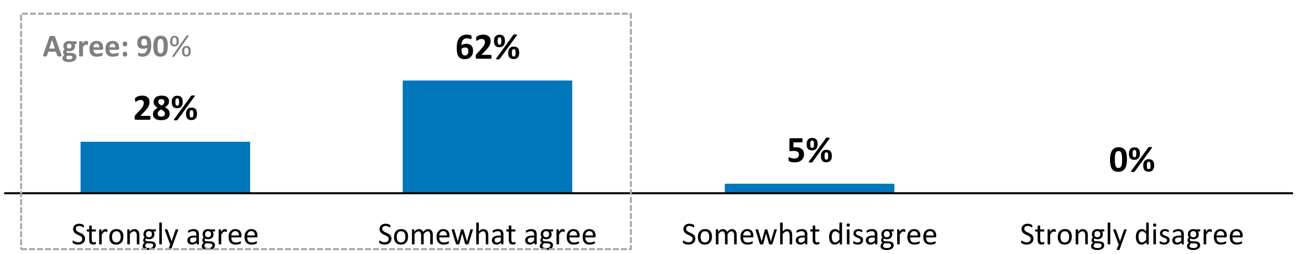
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (5%) not shown.

n=39

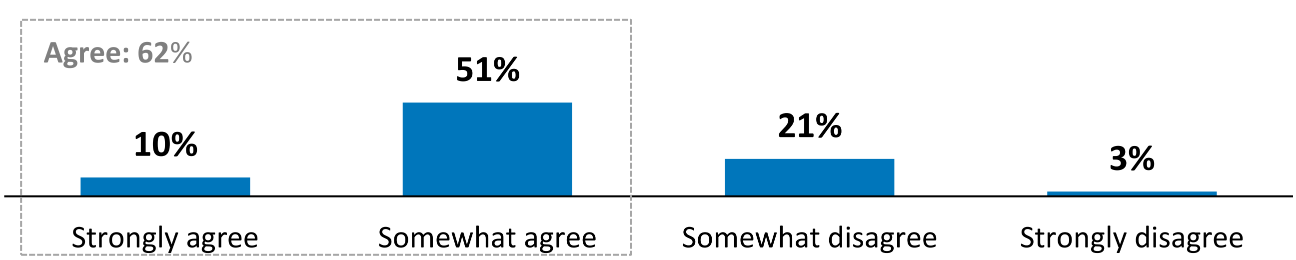
Q Customers are well served by the electricity system in Ontario.



"Don't know/no opinion" (5%) not shown.

n=39

Q Customers are protected with respect to the price we pay for electricity.



"Don't know/no opinion" (15%) not shown.

n=39

Entegrus Main Version GS > 50

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Welcome to Entegrus' customer engagement survey!

The purpose of this survey is to get your feedback on Entegrus' upcoming draft investment plan.

- **Who has been invited to participate?** All Entegrus customers will be invited to participate in this survey. It's important that we hear from a wide range of customers from across the region.
- **What is this survey about?** This survey is focused on key decisions that Entegrus needs to make before finalizing their investment plans.
- **Why participate?** Your electricity rates pay for this plan and Entegrus must demonstrate that customer feedback was incorporated into its plans.
- **How long will the survey take?** The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. The survey is best completed on a laptop or tablet.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Entegrus to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Entegrus in any identifiable way.

INNOVATIVE RESEARCH GROUP

Note: The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.

For the purpose of this exercise, the estimates are based on a customer with average monthly demand of 500 kW and average monthly consumption of 162,500 kWh.

Note: In the workbook, the introduction page differed based on rate zone (Entegrus main or St.Thomas)

Introduction

Summary

St. Thomas Version
GS > 50

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

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INNOVATIVE RESEARCH GROUP

Note: The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.

For the purpose of this exercise, the estimates are based on a customer with average monthly demand of 100 kW and average monthly consumption of 43,800 kWh.

Note: In the workbook, the introduction page differed based on rate zone (Entegrus main or St.Thomas)

Entegrus Customer Engagement Survey
Planning for the Future: 2026-2030 Investment Plan

Before we begin… a bit more about this survey!

Typically, every five years, local distributors like Entegrus are required to file an application with the Ontario Energy Board (OEB) to set rates.

However, as an outcome of the 2018 merger with St. Thomas Energy, Entegrus rates have increased at, or below, the rate of inflation since 2018.

Now, for the first time since the merger, Entegrus will be filing its next rate application that will cover the years 2026-2030.

In this process, Entegrus' rate application will be examined in detail and, again, Entegrus must demonstrate that customer needs and priorities were factored into this process.

Throughout 2024, nearly 2,000 Entegrus customers participated in surveys to aid in the development of Entegrus' draft plans.

Today, Entegrus is looking for your input to ensure that the plans they developed are, in fact, aligned with what customers want and expect.

Later this year, **Entegrus will present its proposed plans and input provided by customers to the OEB.**

You don't need to be an electricity expert to participate. This survey is focused on basic choices and provides the background information you need to answer the questions.

So, what are we going to talk about?

Today's survey will focus on two broad categories.

1. First, we need to ensure that we're all on the same page regarding Entegrus' role in the broader electricity system.
2. Second, you will be asked some questions about specific investment decisions that Entegrus needs to make to finalize their plans.

Familiarity & Experience

Entegrus’ role in Ontario’s electricity system

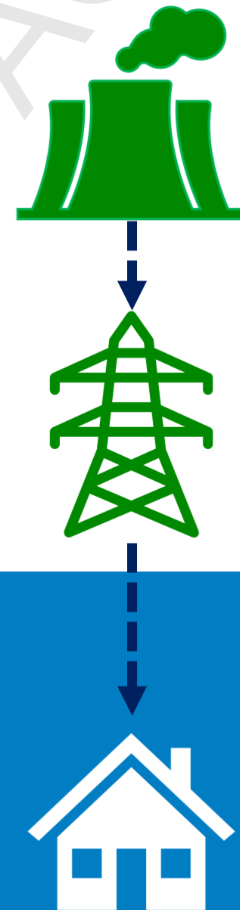
Commercial & Industrial

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

What is Entegrus’ role in Ontario’s electricity system?

Ontario's electricity system is made up of three key components: **generation**, **transmission** and **distribution**.



Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources. About half comes from nuclear power. The remainder comes from a mix of hydroelectric, natural gas, wind and solar. Ontario Power Generation, a government-owned company, generates almost half of Ontario’s electricity.

Transmission

How electricity travels across Ontario

Once electricity is generated, it must be transported to communities across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Most of this system is owned and operated by Hydro One.

Local Distribution

How electricity is delivered to you

Entegrus is responsible for the local distribution system, which takes electricity from transmission lines and brings it to your community.

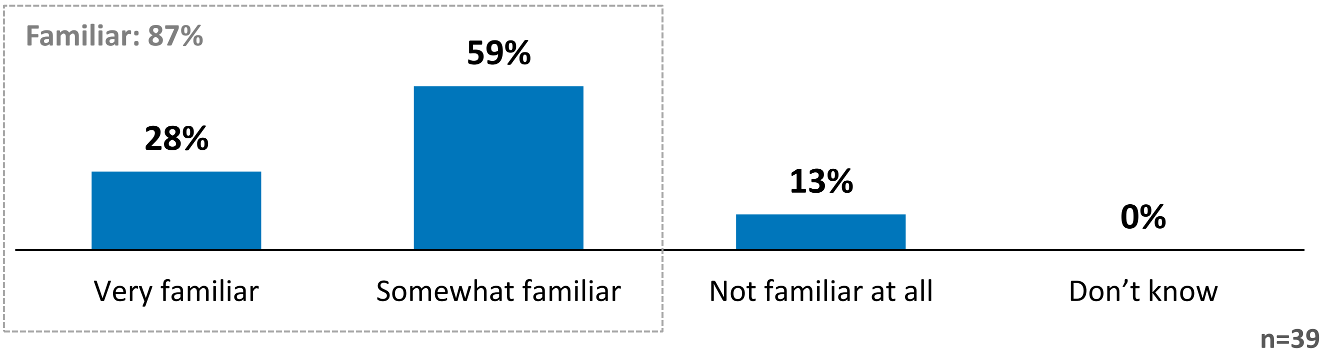
Entegrus builds and maintains power lines, transformers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Entegrus does not generate electricity or set electricity prices.

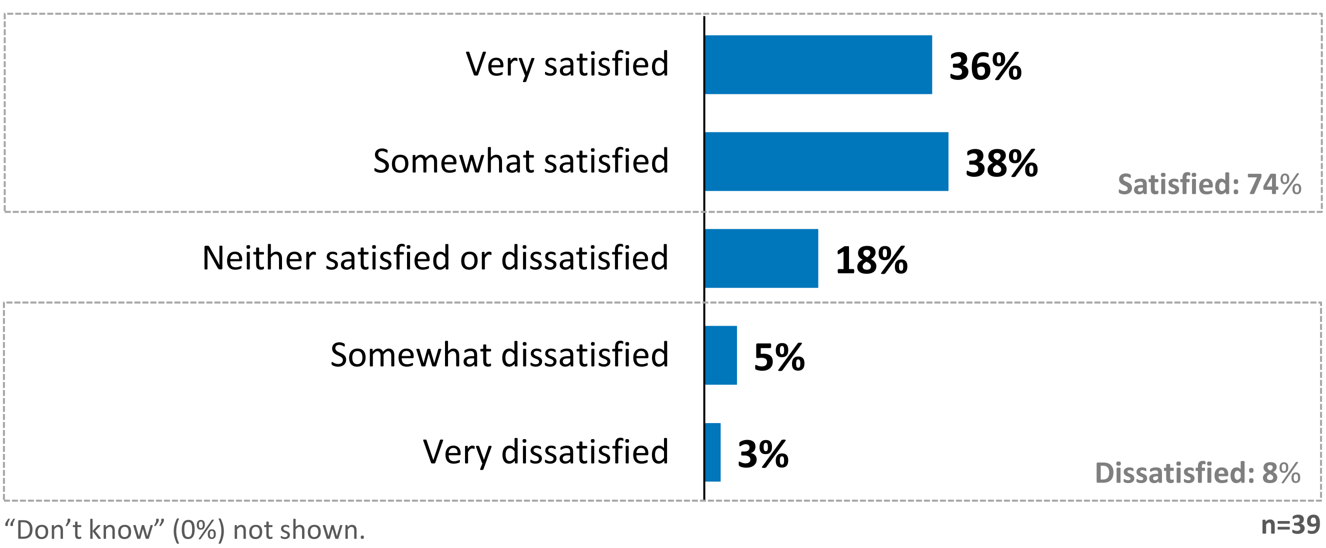
Familiarity & Experience

Familiarity and satisfaction with Entegrus

Q How familiar are you with **Entegrus**, which operates the electricity distribution system in your community?



Q Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that you receive?



Entegrus Customer Engagement Survey
Planning for the Future: 2026-2030 Investment Plan

More about Entegrus

Entegrus owns and operates distribution systems **serving 17 communities in Southwestern Ontario**, stretching between Wheatley (to the west), St. Thomas (to the east), Parkhill (to the north) and Lake Erie (to the south).

- Most of the initial system expansion in the Entegrus communities occurred between 1950 and 1970**.** Some of the equipment in Entegrus' distribution system is more than 50 years old.
- Entegrus' service territory today is a product of multiple mergers and amalgamations dating back to the late-1990s – most recently the amalgamation with **St. Thomas Energy** in 2018.
- Today, Entegrus has operation centres in both Chatham and St. Thomas.

Familiarity & Experience

Portion of bill that goes to Entegrus

Commercial & Industrial

Entegrus Main Version
GS > 50

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much of my electricity bill goes to Entegrus?

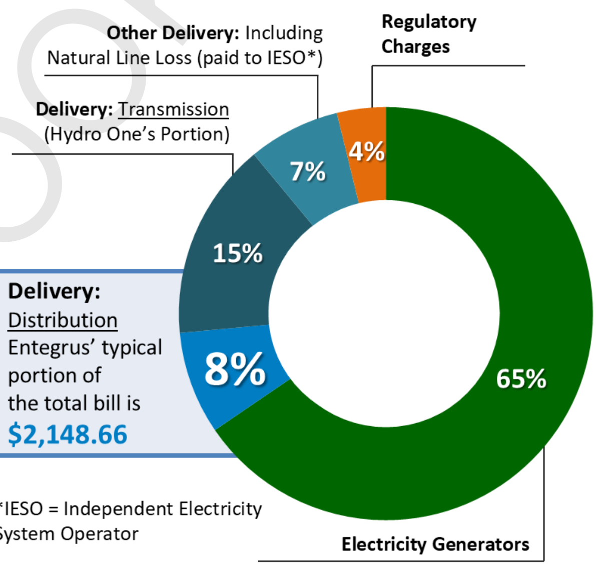
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.
- **For a typical commercial & industrial customer, 8% of the total bill or about $2,149 goes to Entegrus each month.**
- The rest of your bill payment goes to power generation and transmission companies, taxes, and regulatory agencies.

Sample Entegrus Monthly Bill
(based on 500 kW monthly demand as of May 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
IESO Wholesale Electricity	17,485.00
Delivery	8,207.91
Regulatory Charges	1,017.37
Total Electricity Charges	$26,710.28
HST	$3,472.34
Total Amount	$30,182.62



*IESO = Independent Electricity System Operator

The chart above is based on a total bill of $26,710.28 excluding HST. The chart may not total 100% due to rounding.

The sample bill above uses an average monthly demand of 500 kW and average monthly consumption of 162,500 kWh .

Note: In the workbook, sample bills differed based on rate zone (Entegrus main or St.Thomas) and rate class

Familiarity & Experience

Portion of bill that goes to Entegrus

Commercial & Industrial

St. Thomas Version

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much of my electricity bill goes to Entegrus?

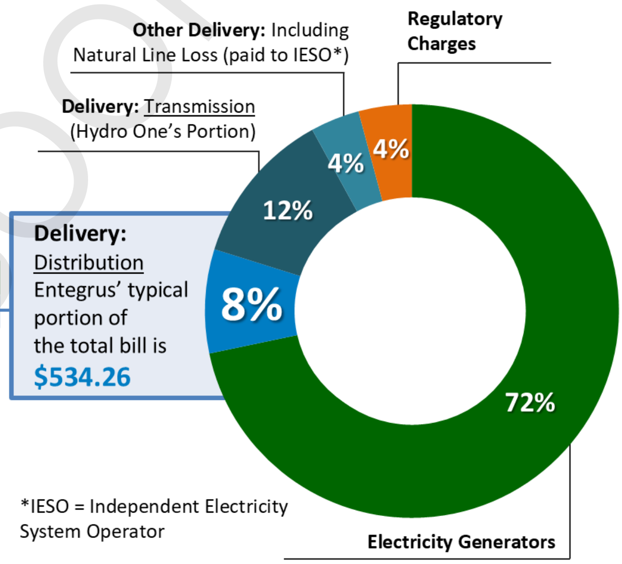
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.
- **For a typical commercial & industrial customer, 8% of the total bill or about $534 goes to Entegrus each month.**
- The rest of your bill payment goes to power generation and transmission companies, taxes, and regulatory agencies.

Sample Entegrus Monthly Bill
(based on 100 kW monthly demand as of May 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
IESO Wholesale Electricity	**4,712.88**
Delivery	**1,586.18**
Regulatory Charges	**273.38**
Total Electricity Charges	**$6,572.43**
HST	$854.42
Total Amount	**$7,426.85**



*IESO = Independent Electricity System Operator

The chart above is based on a total bill of $6,572.43 excluding HST. The chart may not total 100% due to rounding.

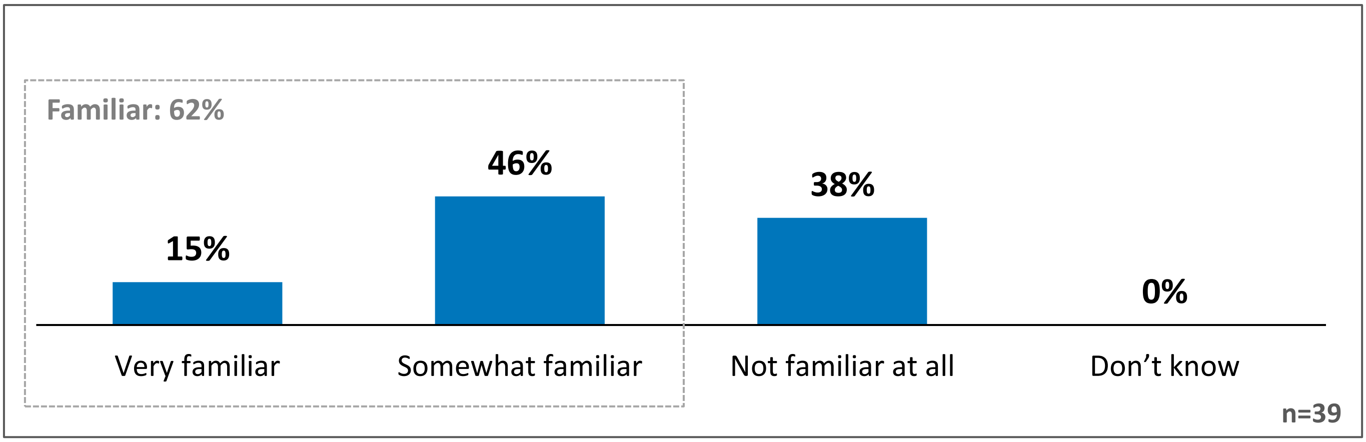
The sample bill above uses an average monthly demand of 100 kW and average monthly consumption of 43,800 kWh.

Note: In the workbook, sample bills differed based on rate zone (Entegrus main or St.Thomas) and rate class

Familiarity & Experience

Bill familiarity

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Entegrus**?



Summary of Investment Plan

What Entegrus has heard so far

Commercial & Industrial

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

What has Entegrus heard from customers so far?

In the summer of 2024, nearly 2,000 Entegrus customers participated in a series of surveys. These surveys included all types of customers, ranging from residential to commercial and industrial. Here's what Entegrus heard:

1	**Most customers prioritize affordability, followed closely by ensuring reliable service.**
2	**Customers largely support investment in maintaining current system reliability.**
3	**Many want Entegrus to proactively invest to ensure customers in higher growth areas do not experience a decline in reliability.**
4	**Customers would like to see Entegrus invest in new technologies when customer benefits are clear.**
5	**Many customers support improvements in customer service that make it easier to view and report outages.**

Entegrus Customer Engagement Survey
Planning for the Future: 2026-2030 Investment Plan

Challenges facing Entegrus' grid

There are many challenges facing the electricity grid that Entegrus will seek to manage in its draft investment plan covering the years 2026-2030. The key challenges facing Entegrus' grid include:

- **Aging and deteriorating infrastructure, some of which is more than 50 years old.**
- **The increased frequency of severe weather in communities served by Entegrus.**
- **Rising costs related to inflation and supply chain disruptions.**
- **Increasing demand for electricity in communities served by Entegrus.**
- **The changing ways customers are using electricity and adoption of new technology.**
- **An increasing industry focus on cyber security and IT systems.**
- **An increasing industry focus on adoption of new technologies.**

In addition to the challenges above, Entegrus is also going to need to be responsive to the **ongoing threat of U.S. tariffs**. The threat of these tariffs make it increasingly difficult to forecast and plan, as costs could change and businesses could shift priorities, resulting in less than anticipated demand for electricity.

Regardless, Entegrus has prepared its 2026-2030 draft investment plan to address these challenges with the ultimate objective of being responsive to external pressures while providing safe and reliable electricity to communities at a reasonable cost.

Summary of Investment Plan

Objectives of the draft investment plan

Commercial & Industrial

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

What is Entegrus' draft plan?

In addition to feedback received from customers, Entegrus has developed its draft plans based on information and input from internal engineering and technical experts who closely monitor the pressures on the distribution system, develop solutions to address these challenges, and recommend investments that inform its plans.

Below are some of the highlights of Entegrus' 2026-2030 draft plan.

1. **Manage rising costs and limiting potential rate increases.**
2. **Maintain current levels of reliability, while targeting improvements for customers experiencing poorer reliability than average.**
3. **Prepare the system to support community growth and respond to new customer requests.**
4. **Explore new technologies to make Entegrus' operations more efficient and offer clear customer benefits.**
5. **Offer customers new ways to view account information, track, and report outages in real-time.**
6. **Ensure that all 17 communities served by Entegrus pay the same for the service they receive.**
7. **Prepare the grid to be more resilient in the face of more frequent severe weather.**

Throughout the remainder of this survey, you will be asked to provide feedback that focuses on these key objectives – where there may be opportunities to do more or less than is currently planned.

But first, Entegrus will tell you about some of the efforts to manage rising costs.

Summary of Investment Plan

What Entegrus is doing to keep costs down

Commercial & Industrial

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

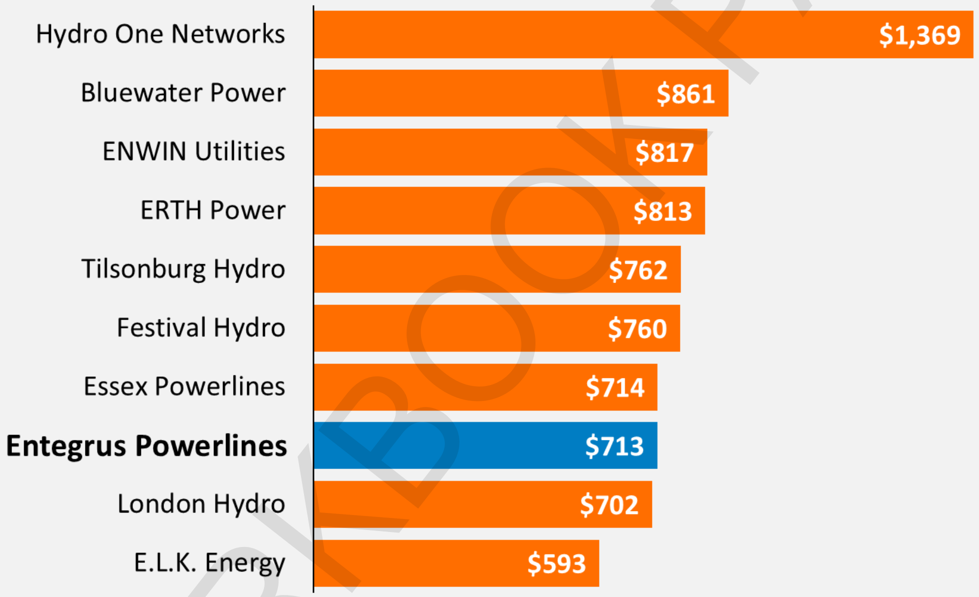
What is Entegrus doing to keep costs down?

According to the latest data published by the Ontario Energy Board, Entegrus is among the most efficient utilities in Southwestern Ontario, as measured by the total cost per customer.

Below is a regional comparison across Southwestern Ontario.

Southwestern Ontario Utility Comparison: Total Cost per Customer

Source: 2023 OEB Electricity Distributor Scorecard



In an effort to keep costs down, Entegrus is a member of the GridSmartCity Co-operative, an organization that brings together 15 Ontario electricity distributors to collaborate and share knowledge, skills and expertise – with some of the goals being increased efficiency and cost savings through economies of scale.

GridSmartCity
renewing energy

Cost saving benefits include negotiated group rates for services and group savings on the procurement of wood poles, cables, wires, and transformers.

Additionally, through its 2018 merger with St. Thomas Energy, Entegrus continues to see annual savings of approximately $1.7 million each year through shared operating, maintenance, and administrative costs.

Summary of Investment Plan

Cost of Entegrus' draft plan to customers

Commercial & Industrial

Entegrus Main Version
GS > 50

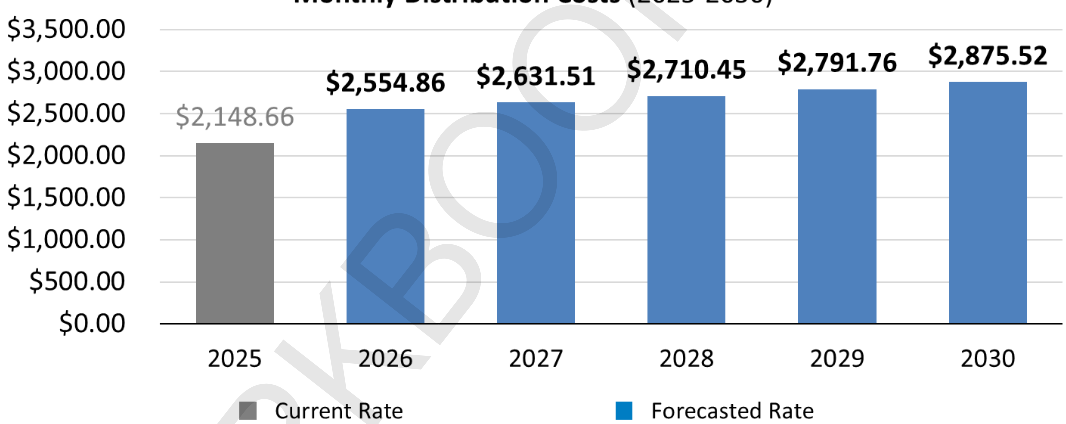
Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much will Entegrus' draft plan cost me?

To achieve the outcomes outlined in Entegrus' draft plan, it is estimated that the typical **commercial & industrial** customer would see the distribution portion of their electricity bill increase by **$726.86** from **$2,148.66 today (2025)** to a proposed rate of **$2,875.52 by 2030**.

Monthly Distribution Costs (2025-2030)



These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical commercial & industrial customer based on a customer with average monthly demand of 500 kW and average monthly consumption of 162,500 kWh.

Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas)

Summary of Investment Plan

Cost of Entegrus' draft plan to customers

Commercial & Industrial

St. Thomas Version
GS > 50

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How much will Entegrus' draft plan cost me?

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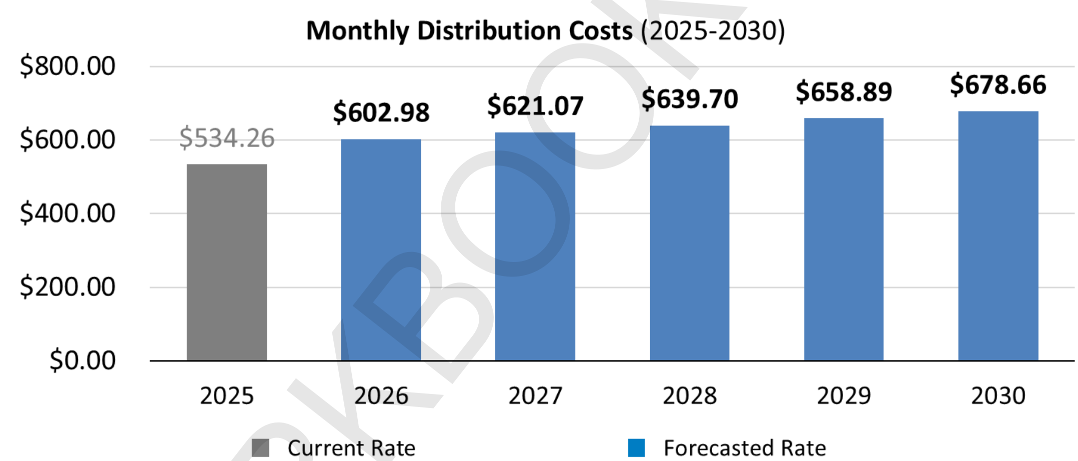

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Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas)

Entegrus Customer Engagement Survey

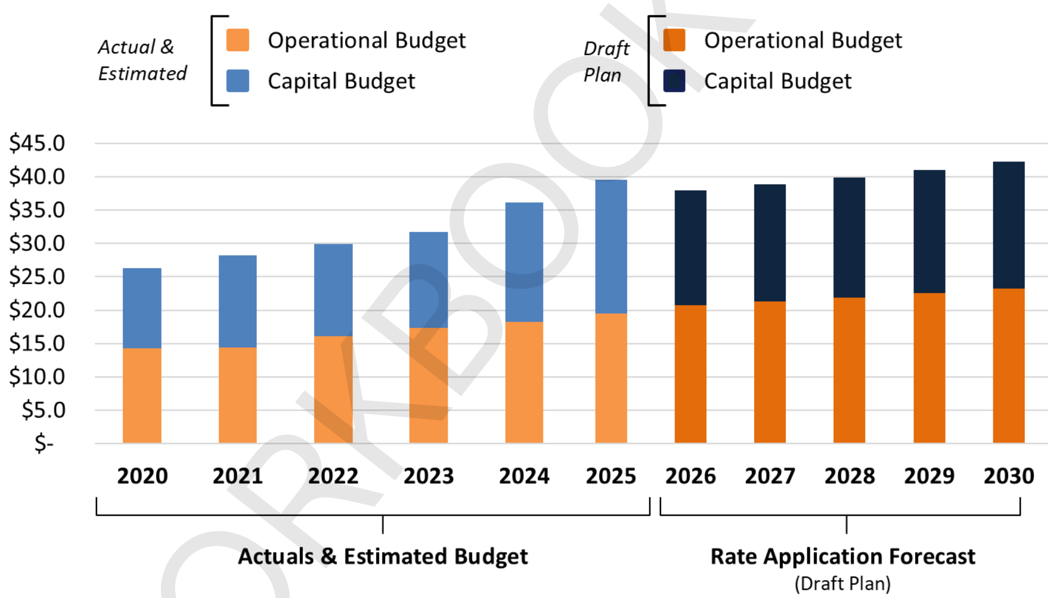
Planning for the Future: 2026-2030 Investment Plan

How does Entegrus plan future investments in the system?

Like most businesses, Entegrus manages both an operating budget and a capital budget.

- The **operating budget** covers recurring expenses, such as the maintenance of assets and tools, customer services, running all business systems and processes, as well as the cost of employees who ensure these activities are completed.
- The **capital budget** includes the costs to build the system, such as the overhead and underground infrastructure, computers and information systems, vehicles and facilities. These items, once purchased, provide long term benefits for many years to come.

Actual and Forecasted Budgets per year ($ millions)



The final budget for 2026-2030 will be adjusted to reflect customer feedback collected through this engagement and any necessary adjustments prior to filing with the OEB. The OEB and other stakeholders will complete an extensive review before rates are set for 2026-2030.

Before these plans can be finalized, Entegrus needs your feedback on the objectives discussed earlier.

Entegrus must demonstrate that their investment plans are directly responsive to customer needs and preferences.

Summary of Investment Plan

How to make choices

Commercial & Industrial

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

How do I make choices?

The remainder of this survey asks for your input on **4 key choices** that will affect the services you receive and the rates that you pay from 2026-2030.

- Each choice has a summary of the options that Entegrus is considering. In many cases, that includes options that would see Entegrus spend less or spend more than what is currently being proposed in the draft investment plan.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance.

Recall, Entegrus is entirely funded by the rates paid by its customers.

That means, the investments that are discussed in the subsequent pages are directly funded by customers.

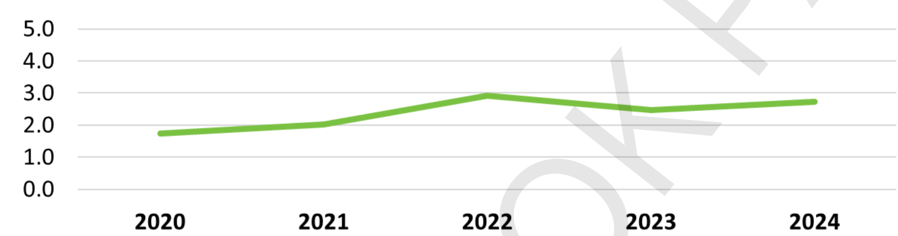
Entegrus Customer Engagement Survey
Planning for the Future: 2026-2030 Investment Plan

Choice 1 of 4: Targeted Reliability Investments

First, let's discuss the reliability of the electricity grid in your community.

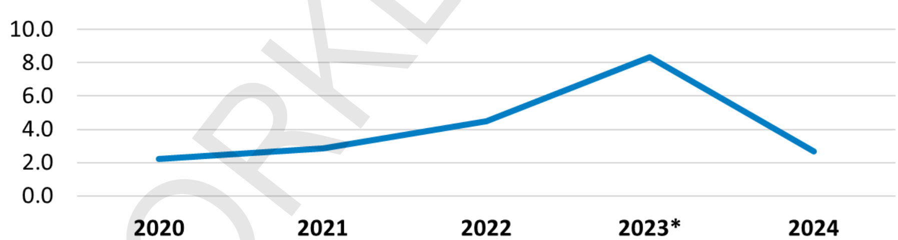
On average, between 2020 and 2024, the typical Entegrus customer has experienced **about 2.4 outages per year**.

Average number of outages (outages per customer)



Over the same period, the **average duration of an outage has been about 4 hours**. Meaning, when the power does go out, Entegrus is typically able to restore power in about four hours.

Average Outage Duration (outage length in hours per customer)



*** In 2023, Entegrus communities experienced four significant storms, resulting in an above average length of time that customers were without power.**

It's important to keep in mind that these are system averages, and that your actual experience may be different. Customers experience different levels of reliability, depending on where they live, the design of the system, and the condition of the equipment supplying them.

Investment Trade-Offs

Targeted reliability investments

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 1 of 4: Targeted Reliability Improvements

In the current draft plan, Entegrus' planners have identified a series of targeted investments to improve reliability for those customers that experience poorer reliability than average. This includes automated switches that allow Entegrus to automatically reroute power during outages, in part, reducing the length of time customers are without power.

Entegrus could accelerate spending in this area, resulting in reliability improvements for more customers who have historically experienced poorer reliability than average.

Or Entegrus could reduce spending in this area, resulting in reliability improvements for fewer customers who have historically experienced poorer reliability than average.

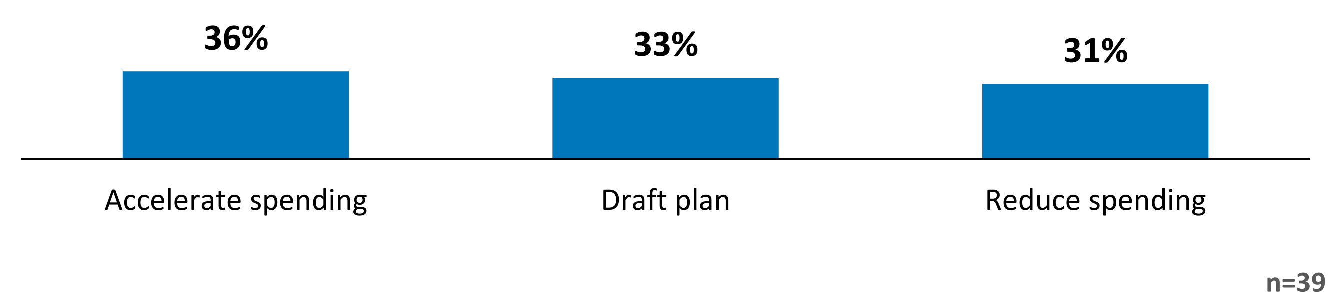
Investment Trade-Offs

Targeted reliability investments

Commercial & Industrial

Q Which of the following options do you prefer?

Option	Expected Outcome(s)
Accelerate spending ***$8.00** more on monthly bill by 2030*	• Make further targeted investments to improve reliability for more customers who experience significantly poorer reliability than average.
Draft plan *Within proposed rate increase*	• Make targeted investments to improve reliability for some customers who experience significantly poorer reliability than average.
Reduce spending ***$4.00** less on monthly bill by 2030*	• Reduce targeted investments to improve reliability for customers experiencing significantly poorer reliability than average.



Q Additional Feedback (Optional)

Verbatim Responses (92% either said 'Don't know' or 'No comment/No response')
"I believe a lot of people's expectations for outages (frequency and duration) are not realistic. Their ability to communicate (typically complain) to you is much easier with social media, this may very well just be a vocal minority. I agree with the draft plan to provide incremental improvements for reliability."
"Reduce when the predict economic is not good, accelerate when opposite."
"When running a business it costs a lot to be without electricity for too long."

Investment Trade-Offs

Preparing for community growth

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 2 of 4: Preparing for Community Growth

As more customers start getting electric vehicles, solar panels, or just generally continue to use electricity differently, more and more equipment will need to be upgraded to accommodate these changes. If demand increases quicker than expected in a specific community, this could strain the system and lead to equipment failing more frequently.

Transformers are a critical piece of equipment that help accommodate this changing electricity usage. They are located throughout your community and are usually mounted on top of wooden poles.

As a rule of thumb, the larger the transformer, the more electricity it can serve to the homes and businesses on the other end of the wire. Today, the smaller transformers that have historically served residential homes are increasingly struggling to keep up with demand.

In the current draft plan, Entegrus will upgrade transformers reactively as they fail and install bigger transformers for new homes being constructed.

Alternatively, Entegrus could introduce a new program to proactively upgrade transformers that are most at risk of overloading and therefore failure. Proactive replacement can:

a) Help ensure that customers have access to enough electricity when they need it

b) Reduce the risk of need for reactive replacement – and reducing outage durations – when equipment does fail.

That said, proactive replacement does not necessarily reduce the current risk of outages. The benefit is more about preparing the grid for the future and minimizing future reliability risks.

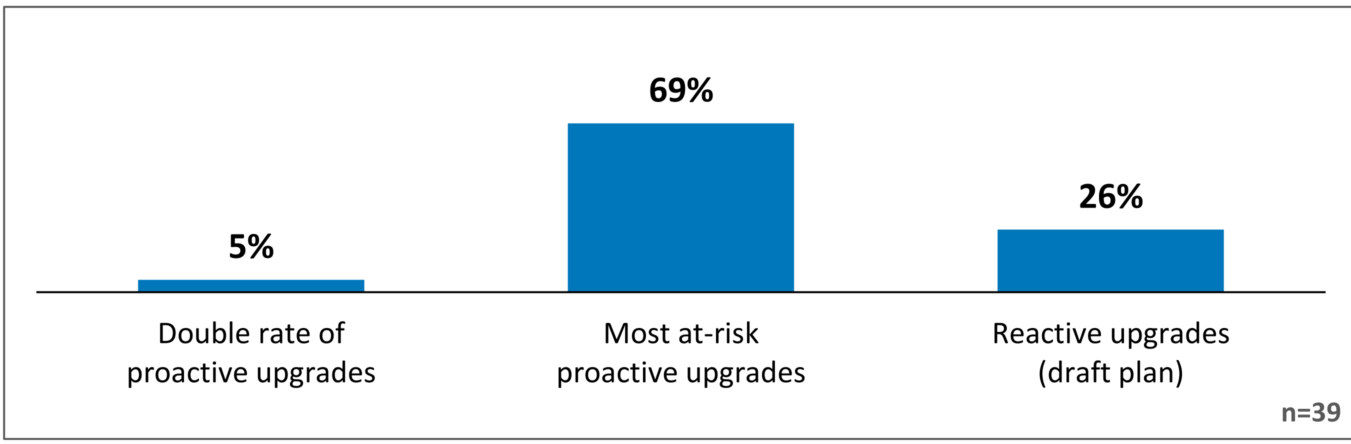
Investment Trade-Offs

Preparing for community growth

Commercial & Industrial

Q Which of the following options do you prefer?

Option	Expected Outcome(s)
Double rate of proactive upgrades ***$16.00 more*** *on monthly bill by 2030*	• Double the rate of proactive upgrades of most at-risk transformers • Further reduce the risk of outages due to transformer failures
Most at-risk proactive upgrades ***$8.00 more*** *on monthly bill by 2030*	• Proactively upgrade most at-risk transformers • Potentially reduce the risk of outages due to transformer failures
Reactive upgrades (draft plan) *Within proposed rate increase*	• Maximize the useful life of current transformers • Potential for higher levels of unplanned outages due to transformer failures



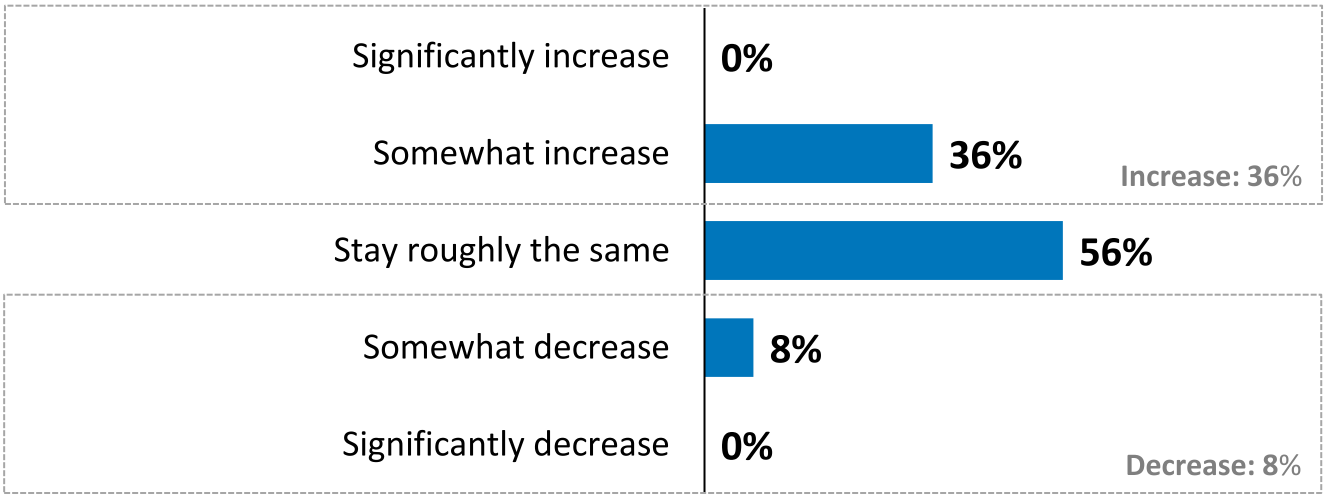
Q Additional Feedback (Optional)

Verbatim Responses (95% either said 'Don't know' or 'No comment/No response')
"Hydro is too expensive here in St. Thomas/Ontario."
"I do not think that a reactive upgrade plan is in the best interest of the community, nor Entegrus."

Investment Trade-Offs

Preparing for community growth

Q In the next five years, do you anticipate your organization's electricity usage will increase, decrease, or stay roughly the same?



"Don't know" (0%) not shown.

n=39

Investment Trade-Offs

Tree and vegetation trimming

Commercial & Industrial

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 3 of 4: Tree and Vegetation Trimming

The third investment Entegrus would like your feedback on is on emerging technology to better monitor Entegrus' distribution system.

Entegrus serves 17 communities and has thousands of trees across its service territory and in proximity to its lines.

On a regular basis, Entegrus must ensure those trees remain a safe distance from electrical equipment like poles and wires. Currently, on a multi-year cycle, Entegrus goes community-by-community to trim trees and other vegetation. In a typical year, outages due to tree contacts account for approximately 7-19% of all customer outages.

In previous surveys, many customers said that they would support Entegrus piloting new technology that would use satellites to build a 3D model of vegetation and lines across the communities served by Entegrus. This technology would allow for more precise planning to minimize the magnitude of trimming required.

As planning has progressed, Entegrus has identified an opportunity to expand this pilot to even further minimize tree contacts and reduce potential delays during large infrastructure projects. This would include augmenting the satellite modeling with more frequent and targeted ground-based scans, getting into more difficult to reach areas.

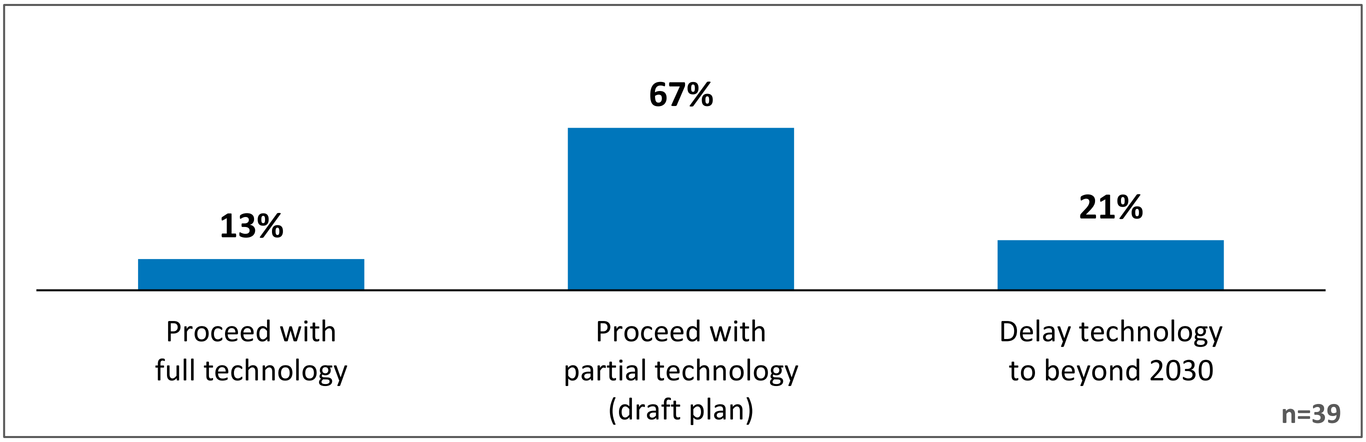
Currently, the draft plan includes piloting the satellite scans, however, Entegrus would like to hear if you would like them to do more or less. To keep costs down, Entegrus could continue with its current time-based approach to tree trimming and vegetation management.

Investment Trade-Offs

Tree and vegetation trimming

Q Which of the following options do you prefer?

Option	**Expected Outcome(s)**
Proceed with full technology ***$4.75*** *more on monthly bill by 2030*	• Allow targeted tree trimming and scanning of harder to reach areas in Entegrus' service territory, not completed with partial technology approach • May further reduce the number of outages caused by tree contacts than with partial technology
Proceed with partial technology (draft plan) *Within proposed rate increase*	• Allow for more targeted tree and vegetation trimming than the typical, manual approach • May reduce the number of outages caused by tree contacts
Delay technology to beyond 2030 ***$11.00*** *less on monthly bill by 2030*	• Continue with the current approach to tree and vegetation trimming • Unchanged likelihood of outages caused by tree contacts



Investment Trade-Offs

Tree and vegetation trimming

Commercial & Industrial

Q Additional Feedback (Optional)

Verbatim Responses (92% either said 'Don't know' or 'No comment/No response')
"How about they state some sort of policy where it is prohibited to have any trees near the lines so that it eliminates outages by tree contact completely? There isn't enough information outlining what full/partial technology means. How are you targeting the trees? What technology? I think we pay enough. I don't think these things should be put onto the consumer."
"How many trees in dangerous situation?"
"Maintain draft plan and review the benefits of it moving forward. Hopefully, it will identify the savings is sufficient to expand it within the current budget framework."

Investment Trade-Offs

Mobile application upgrades

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choice 4 of 4: Mobile Application Upgrades

The fourth investment Entegrus would like your feedback on is on a mobile application.

Again, in earlier research, many customers expressed interest in expanded customer service offerings, specifically an app that includes **access to My Account (the Entegrus online customer account portal), an outage map** and the **ability to report outages**.

In response to this feedback, Entegrus' draft plan includes investment to support the launch of a mobile application that provides these features. While this investment is responsive to customer feedback, Entegrus would like to confirm that customers would like them to proceed, knowing the full cost of this investment.

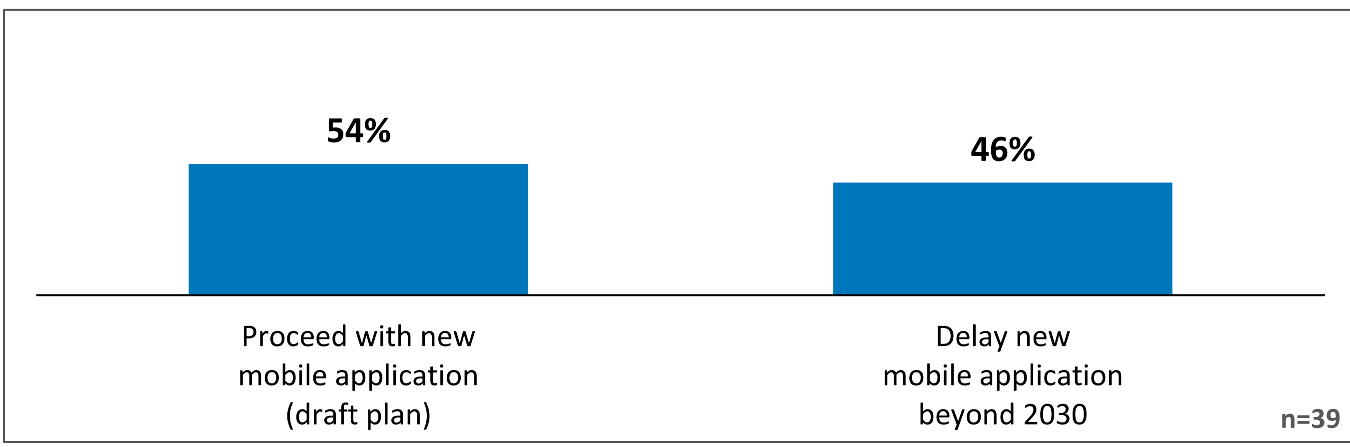
Investment Trade-Offs

Mobile application upgrades

Commercial & Industrial

Q Which of the following options do you prefer?

Option	Expected Outcome(s)
Proceed with new mobile application (draft plan) *Within proposed rate increase*	• Allow customers the ability to access MyAccount, an outage map, and report outages online through a mobile application.
Delay new mobile application beyond 2030 ***$7.00** less on monthly bill by 2030*	• Continue with Entegrus' existing customer service offerings without proceeding with a new mobile application.



Q Additional Feedback (Optional)

Verbatim Responses (95% either said 'Don't know' or 'No comment/No response')
"An outage map is becoming a defacto standard for utilities. I think this needs to be moved on."
"Your firm regularly posts outages on social media and other avenues. I do not think that an app would have much benefit in this regard."

Investment Trade-Offs

Finalizing Choices

Commercial & Industrial

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Choices Calculator

Throughout this survey, you have been asked about 4 key choices from that could impact your rates. Below is a summary of your choices.

At the bottom of this page, you will find the total rate impact of your choices.

Please review your answers and change your responses if you desire, and your potential rate impact will be re-calculated. You can adjust your choices until you reach the best balance for you.

Investment Trade-Offs

Finalizing Choices

Commercial & Industrial Customer Bill Impact Change and Magnitude of Bill Impact

Range of Impacts

-$22.00 to +$28.75

About the "Range of Impacts"

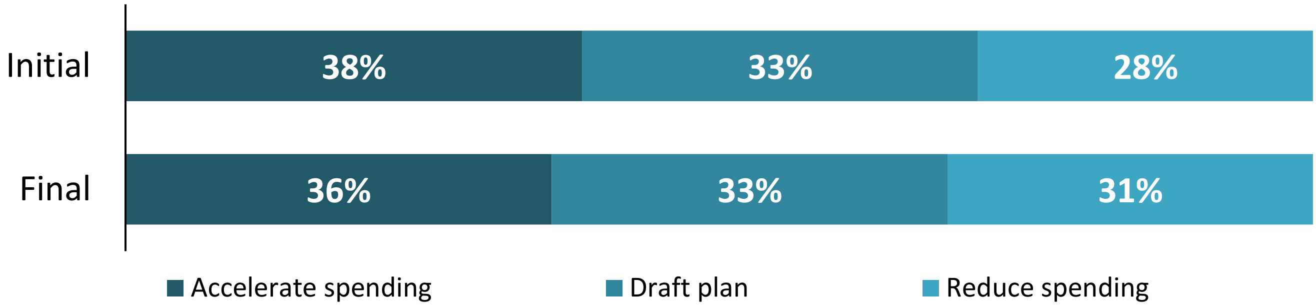
The "Range of Impacts" signifies the highest and lowest possible range of bill impacts above and beyond the Draft Plan. For instance, if a customer, where possible, were to select the biggest increase for each choice, their bill impact would result in **$28.75 more** per month by 2030 when compared to the draft plan. If they were to select the biggest decrease for each choice, it would result in **$22.00** less per month by 2030 when compared to the draft plan.

Investment Trade-Offs

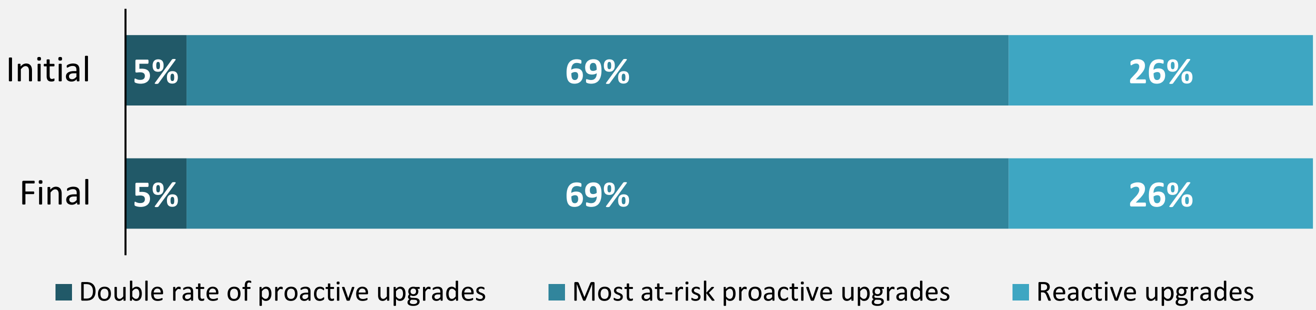
Finalizing Choices

Commercial & Industrial

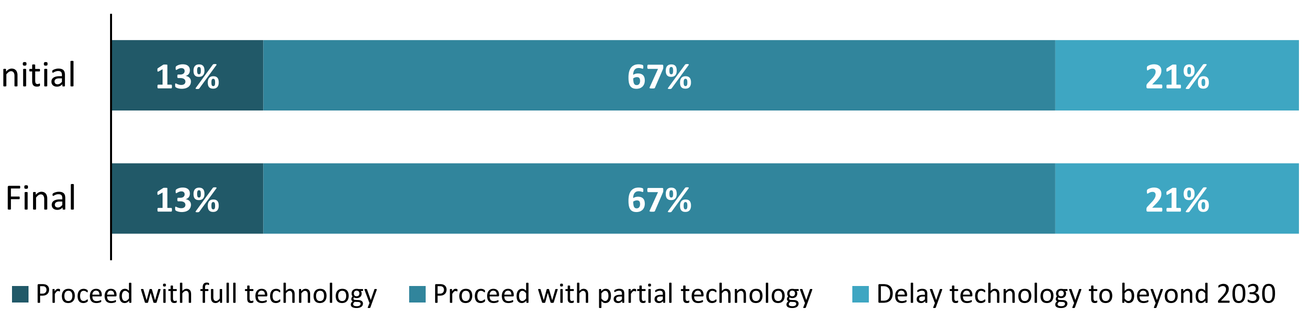
Targeted Reliability Improvements



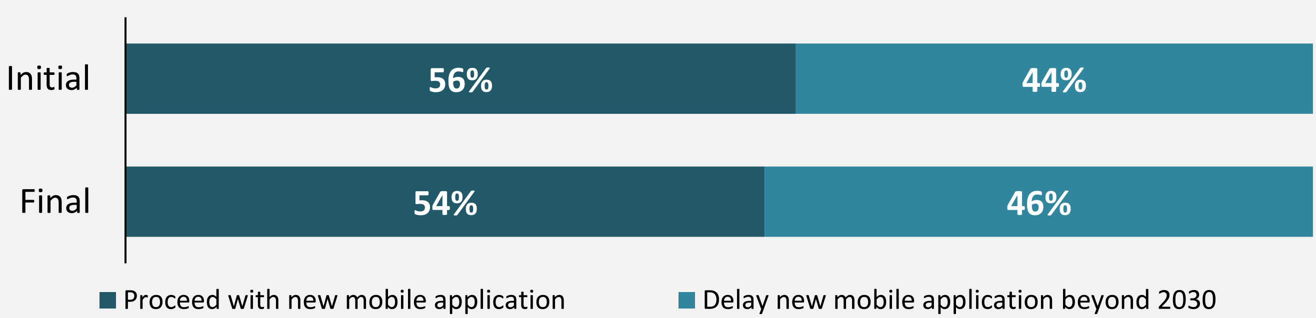
Preparing for Community Growth



Tree and Vegetation Trimming



Mobile Application Upgrades



Investment Trade-Offs

Overall evaluation of the plan

Commercial & Industrial

Entegrus Main Version
GS > 50

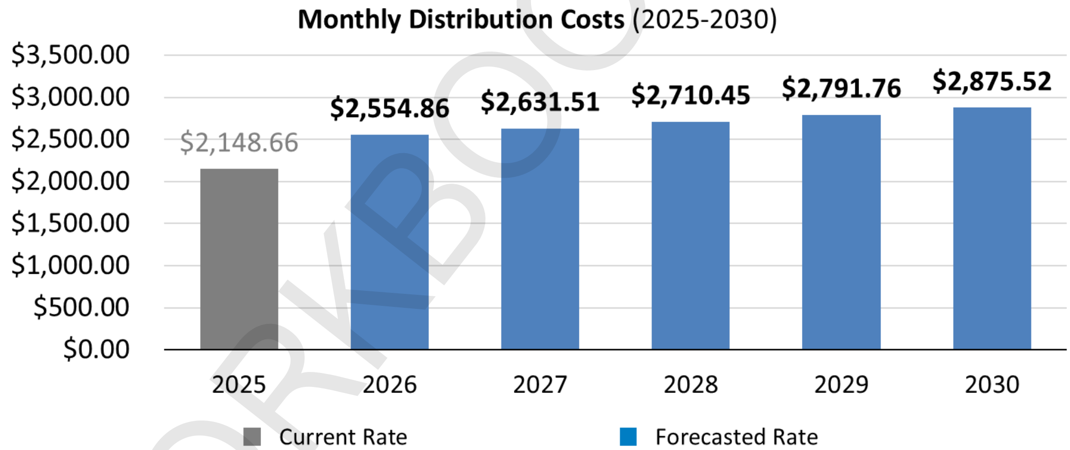
Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Assessing Entegrus' draft 2026-2030 plan

Entegrus has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Entegrus would like to know how you feel about the overall draft plan.

It is estimated that the typical **commercial & industrial** customer would see the distribution portion of their electricity bill increase by **$726.86** from **$2,148.66 today (2025)** to a proposed rate of **$2,875.52 by 2030**.



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Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas)

Investment Trade-Offs

Overall evaluation of the plan

Commercial & Industrial

St. Thomas Version
GS > 50

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Assessing Entegrus' draft 2026-2030 plan

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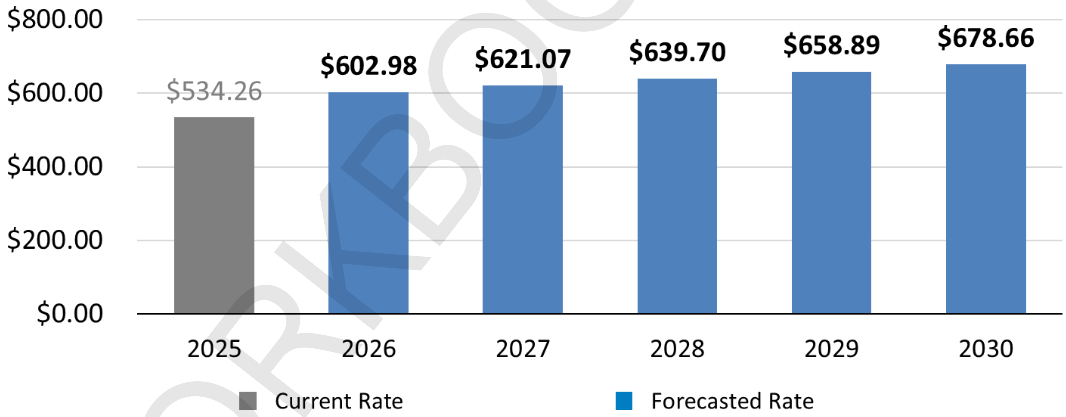

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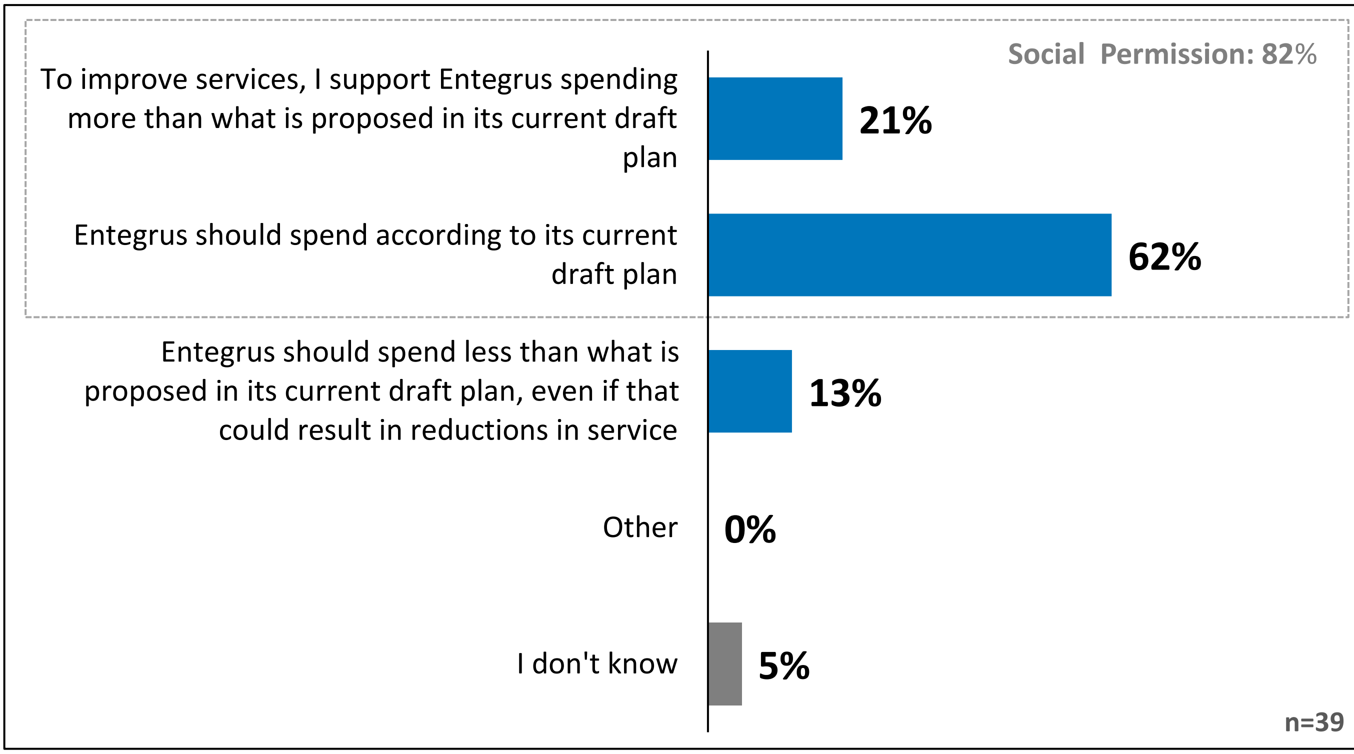
Note: In the workbook, monthly distribution costs differed based on rate zone (Entegrus main or St.Thomas)

Investment Trade-Offs

Overall evaluation of the plan

Commercial & Industrial

Q Considering what you have learned about Entegrus' 2026–2030 draft plan, which of the following best represents your point of view?



Investment Trade-Offs

Final comments on the draft plan

Commercial & Industrial

Q Do you have any final comments regarding Entegrus' draft plan for 2026–2030 and the proposed rate increase?

Verbatim Responses (87% either said 'Don't know' or 'No comment/No response')
"I believe a 25% hike in fees over 4 years is steep."
"I think that outages and reliability are really paramount to this service and as such feel that Entegrus should concentrate its investments in ensuring equitable hydro access for all users by proactively upgrading areas slated for growth, ensuring trees are maintained away from power lines and going underground in every possible instance to ensure reliability into the future as more and more severe wind storms come through the area. This area is notoriously budget conscious and typically do not understand."
"It doesn't matter what happens or how proactive we try to be, these prices go up regardless. As a Canadian business trying to stay in Canada, we need to reduce this cost as much as we can. It is one of our biggest expenses and it hurts."
"It seems most of the outages experienced are not the cause of Entegrus. We've had a number that we are not notified of, and when I call in, I am advised the outage is a Hydro One planned outage. Entegrus must get notified by Hydro One. In turn, it should be the owners of Entegrus to notify its customers of planned outages."
"This draft plan provides for a 34% increase over 5 years. Where does Entegrus hope, their customers are going to find this extra 34% from? It's greater than the cola % or inflation projections. Between the property tax increases and utility increases, doing business in [REDACTED] is becoming cost prohibitive."

Note: Only responses >0.1% shown.

Rate Harmonization

Impact of rate harmonization

Entegrus Main Version
GS > 50

Entegrus Customer Engagement Survey
Planning for the Future: 2026-2030 Investment Plan

Rate Harmonization

A key principle for rates in Ontario is that similar customers should pay the same cost for similar service, regardless of where they are located within a utility service area. As a result of the 2018 amalgamation between Entegrus and St. Thomas Energy, this is not currently the case for all Entegrus customers.

Rate harmonization means bringing two sets of distribution rates into one harmonized rate so that all Entegrus customers in the same rate class pay the same for electricity distribution.

Since merging in 2018, there have been two different sets of rates – one set of rates for the 16 legacy Entegrus communities and one set of rates for St. Thomas.

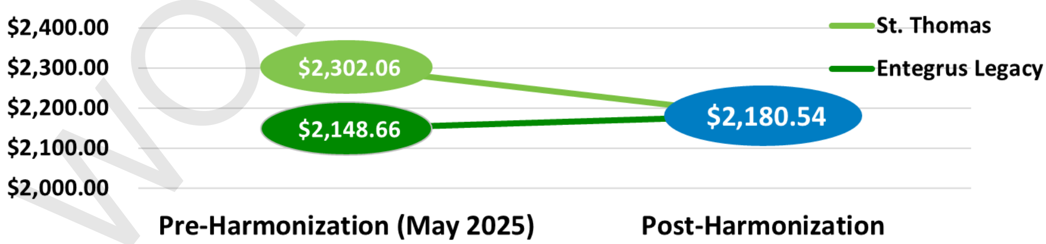
How will it impact me?

Starting in 2026, Entegrus is planning to harmonize rates for all 17 communities. This means that some customers would have a small increase on their bill while others will see a small decrease. **This change will represent less than 1% of the typical total bill.**

Before proceeding, Entegrus would like your feedback on this proposed change.

The chart below shows the impact of rate harmonization on customer rates.

Rate Harmonization Impact on Distribution Rates
Illustrative 2025 Rate Harmonization



These illustrative estimates are calculated without the 2026 rate increase associated with the draft plan discussed throughout this survey and are subject to customer feedback and regulatory approval.

Note: In the workbook, rate harmonization impacts differed based on rate zone (Entegrus main or St.Thomas).

Rate Harmonization

Impact of rate harmonization

Commercial & Industrial

St. Thomas Version
GS > 50

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Rate Harmonization

A key principle for rates in Ontario is that similar customers should pay the same cost for similar service, regardless of where they are located within a utility service area. As a result of the 2018 amalgamation between Entegrus and St. Thomas Energy, this is not currently the case for all Entegrus customers.

Rate harmonization means bringing two sets of distribution rates into one harmonized rate so that all Entegrus customers in the same rate class pay the same for electricity distribution.

Since merging in 2018, there have been two different sets of rates – one set of rates for the 16 legacy Entegrus communities and one set of rates for St. Thomas.

How will it impact me?

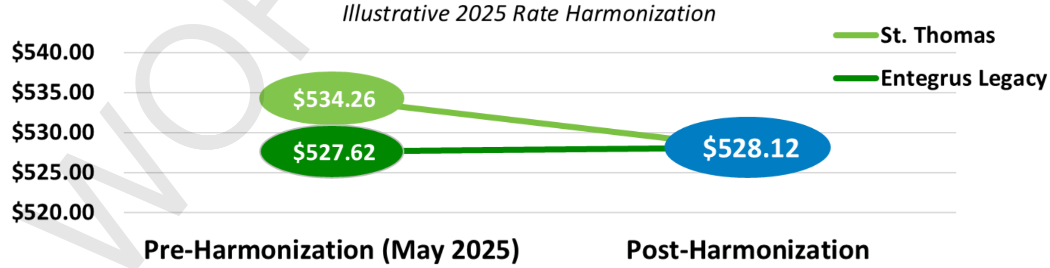
Starting in 2026, Entegrus is planning to harmonize rates for all 17 communities. This means that some customers would have a small increase on their bill while others will see a small decrease. **This change will represent less than 1% of the typical total bill.**

Before proceeding, Entegrus would like your feedback on this proposed change.

The chart below shows the impact of rate harmonization on customer rates.

Rate Harmonization Impact on Distribution Rates

Illustrative 2025 Rate Harmonization



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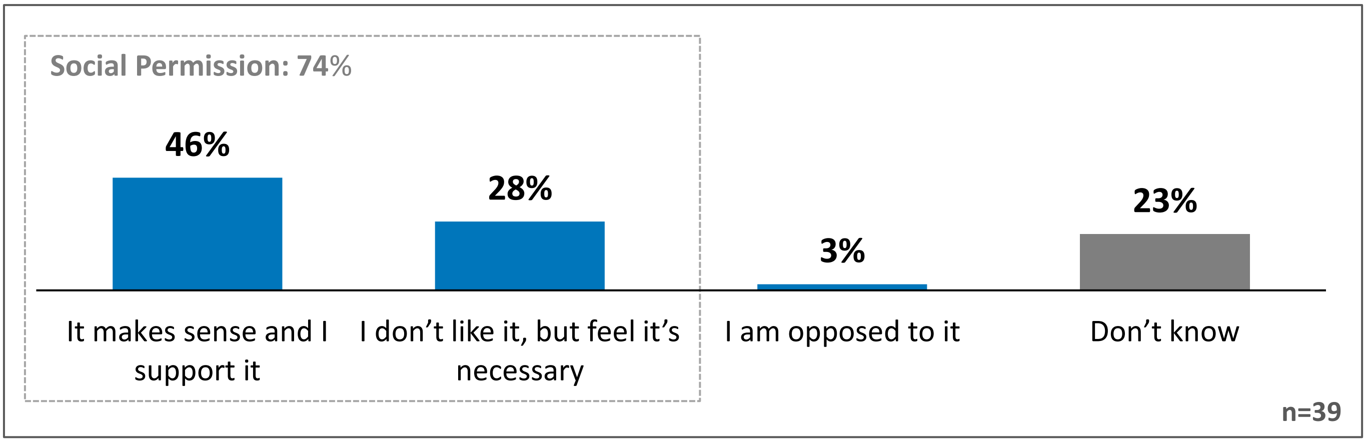
Note: In the workbook, rate harmonization impacts differed based on rate zone (Entegrus main or St.Thomas).

Rate Harmonization

Social permission on rate harmonization

Commercial & Industrial

Q Which of the following best describes how you feel about rate harmonization?



Standby Rates

Impact of standby rates

Entegrus Customer Engagement Survey

Planning for the Future: 2026-2030 Investment Plan

Standby Rates

Standby rates in Ontario are charges applied to customers who maintain a connection to the grid primarily for backup purposes, such as those using on-site generation like generators or renewable energy. Standby charges apply to commercial and industrial customers, such as large factories. **These charges are paid directly by those customers, not all customers.**

These charges are designed to recover costs associated with providing a connection for backup power (for instance, if on-site generation is down for maintenance or temporary failure) and maintaining the distribution system.

Currently, standby rates are applied to 16 out of the 17 communities served by Entegrus Since the amalgamation in 2018 (and prior), standby rates did not apply to customers in St. Thomas.

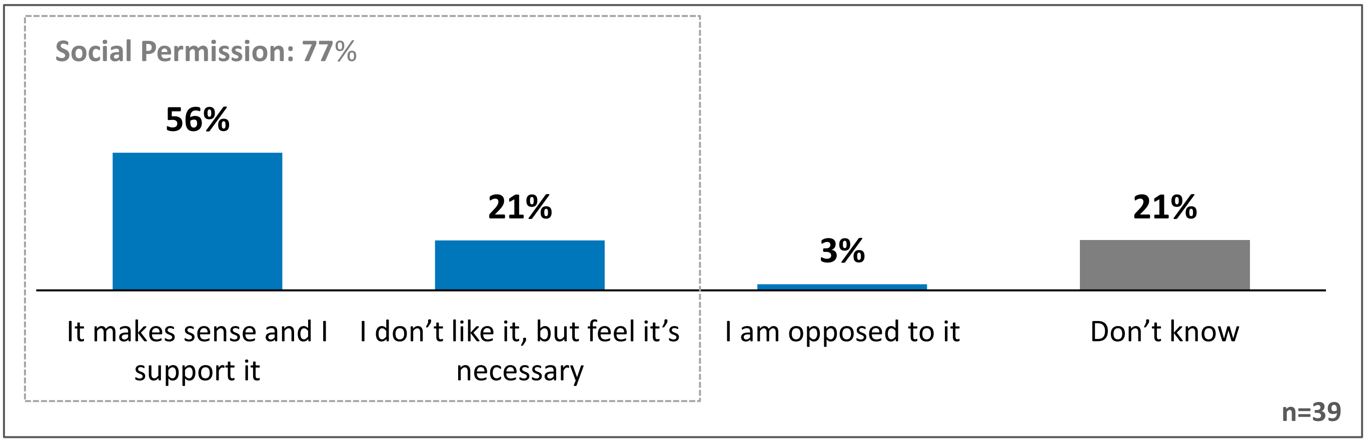
While these charges largely only apply to and are paid by commercial and industrial customers, Entegrus would like your feedback on whether standby rates should be extended to St. Thomas customers who have backup power connections, to be consistent with the rest of the communities served by Entegrus.

Standby Rates

Social permission on standby rates

Commercial & Industrial

Q Which of the following best describes how you feel about extending standby rates to customers in St. Thomas?



INNOVATIVE RESEARCH GROUP

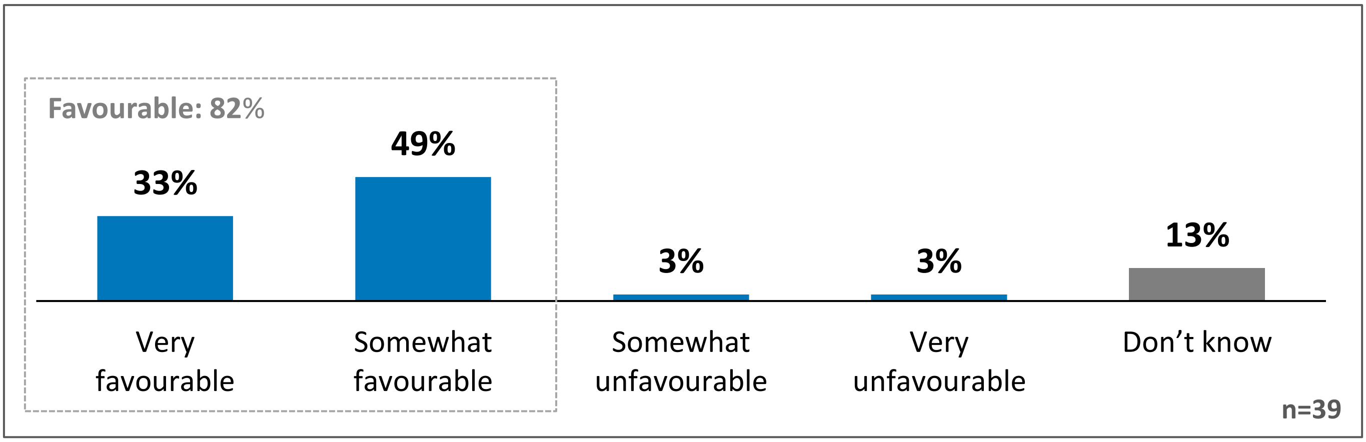
Commercial & Industrial/Large Use Customers

Workbook Diagnostics

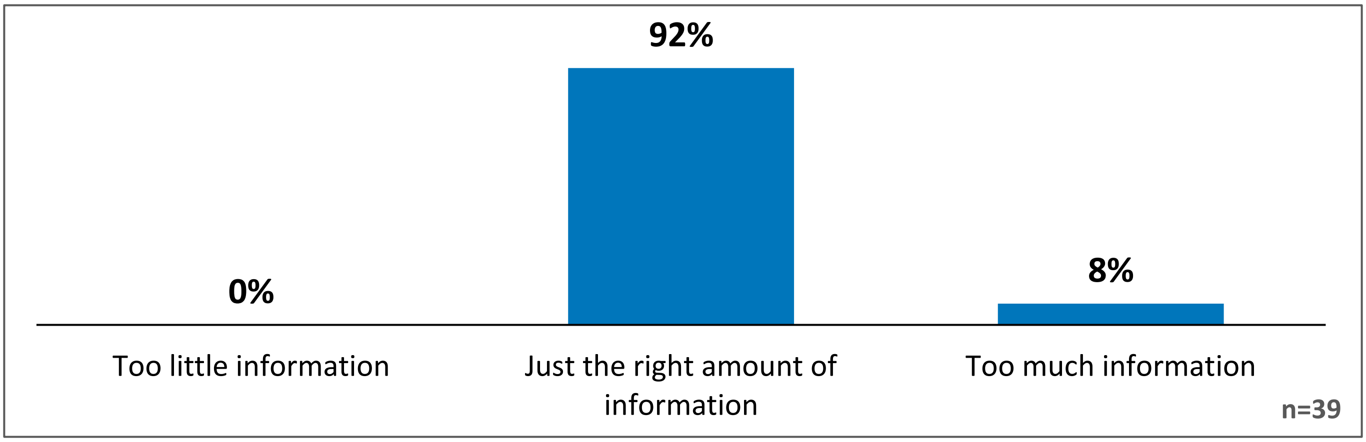
Workbook Diagnostics
Favourability and amount of information

Commercial & Industrial

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Entegrus provided too much information, not enough, or just the right amount?



Workbook Diagnostics

Missing content and remaining questions

Commercial & Industrial

Q Was there any content missing that you would have liked to have seen included in this customer engagement?

Verbatim Responses (92% either said 'Don't know' or 'None')
"Agriculture is an important part of the area and population that Entegrus services and your survey should seek to address the needs of this integral part of the customers that you serve."
"I think that there should have been more information around rate harmonization such as maintenance intervals or other details that may be pertinent to a decision. Is St. Thomas paying more for distribution because their local grid has lacked proper maintenance? Is the St. Thomas grid on an equivalent level as the others in your network in terms of maintenance and other service requirements? What is the effect of rate harmonization for maintenance of existing infrastructure and how much will the St Thomas grid require in the next 5 years as compared to the grids in the surrounding communities?"
"More visibility of what the new technologies are going to cost (cost structure breakdown)."

Q Is there anything that you would still like answered?

Verbatim Responses (97% either said 'Don't know' or 'None')
"See above [I think that there should have been more information around rate harmonization…]. Otherwise, this was an informative document."
"What are the salaries of top administration at Entegrus?"

Note: Only responses >0.1% shown.

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Entegrus Powerlines Inc. The conclusions drawn and opinions expressed are those of the authors.

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INNOVATIVE
RESEARCH GROUP

Needs and Preferences Survey

Phase I Customer Engagement

August 2024

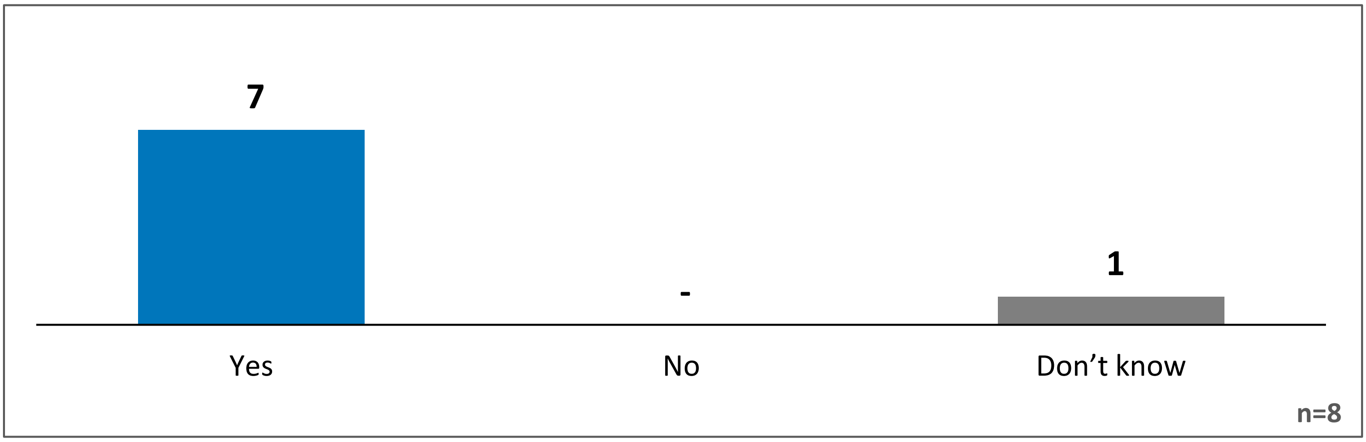
ENTEGRUS®

Uncertainty in business operations

Entegrus is gathering input from its largest customers to understand how recent and potential Canada–US trade and tariff changes are affecting your operations. Your feedback will help inform Entegrus' load forecasts.

As previously mentioned, Innovative Research Group is collecting this feedback on behalf of Entegrus. However, at no point will your individual responses be shared with Entegrus. Your responses will remain completely anonymous.

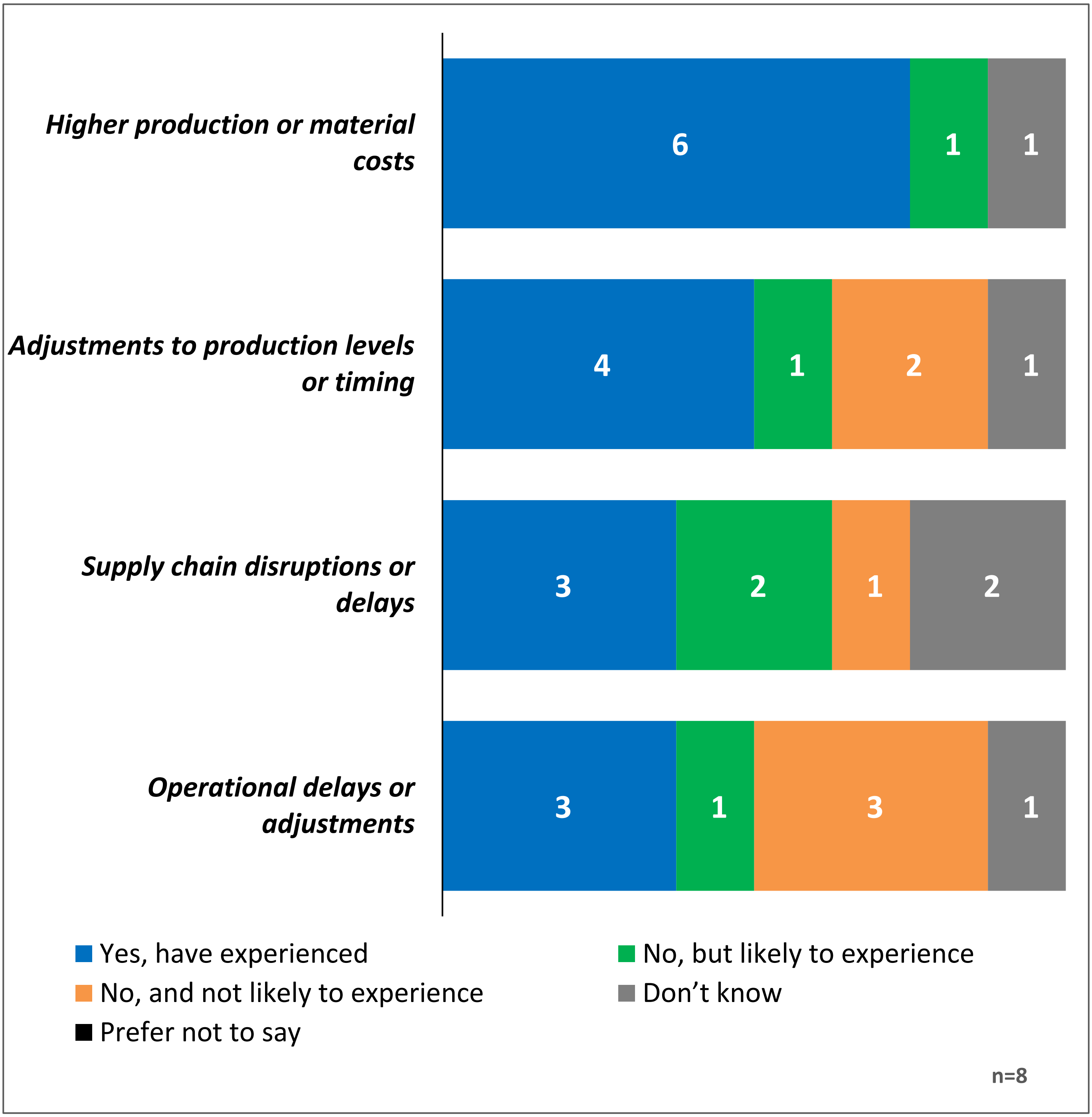
Q Have the Canada-US trade and tariff changes created **uncertainty** in your businesses' operations?



Tariff impacts

Q

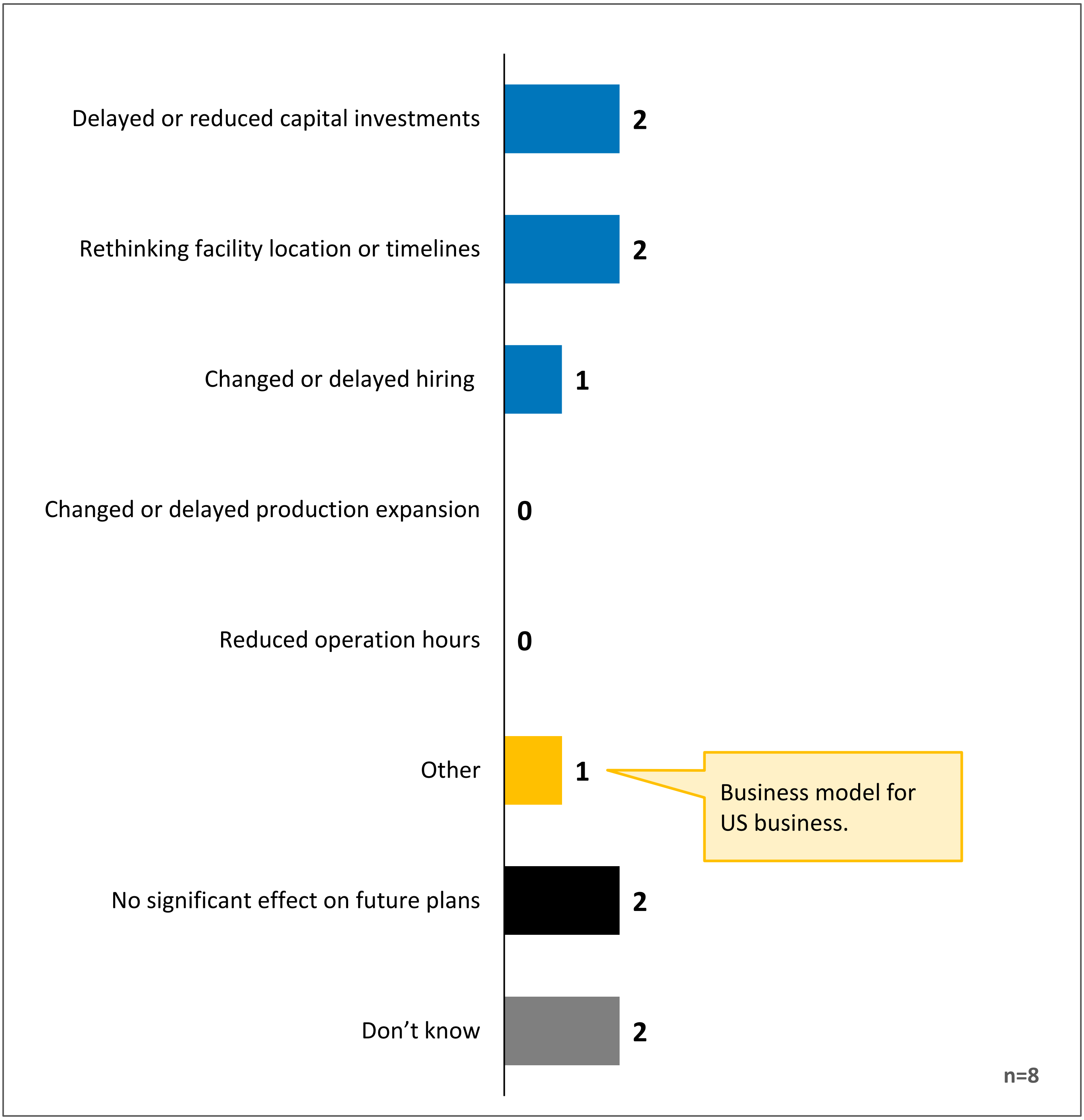
Have you or do you anticipate experiencing the following impacts as a result of the Canada-US trade and tariff changes?



INNOVATIVE RESEARCH GROUP

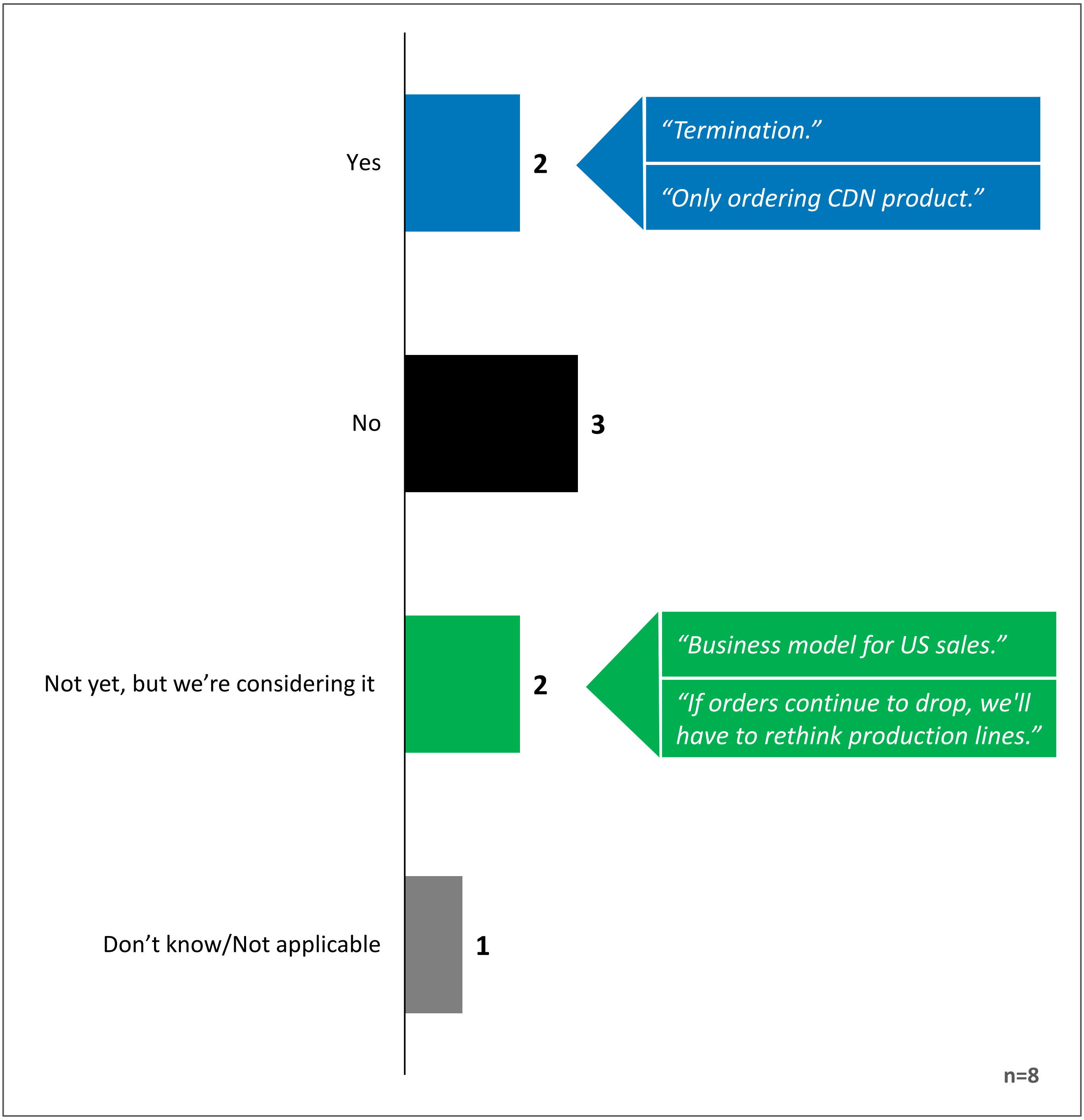
Impact on future plans

Q Have the Canada-US trade and tariff changes affected your future plans in any of the following ways? *Select all that apply.*



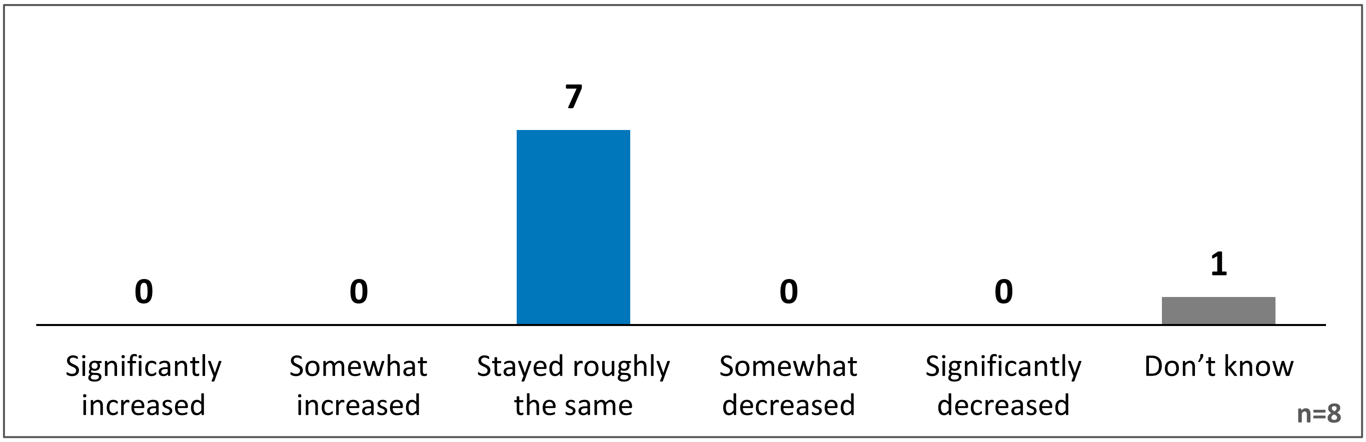
Operations changes

Q Have you already made any operational changes in response to trade or tariff issues?

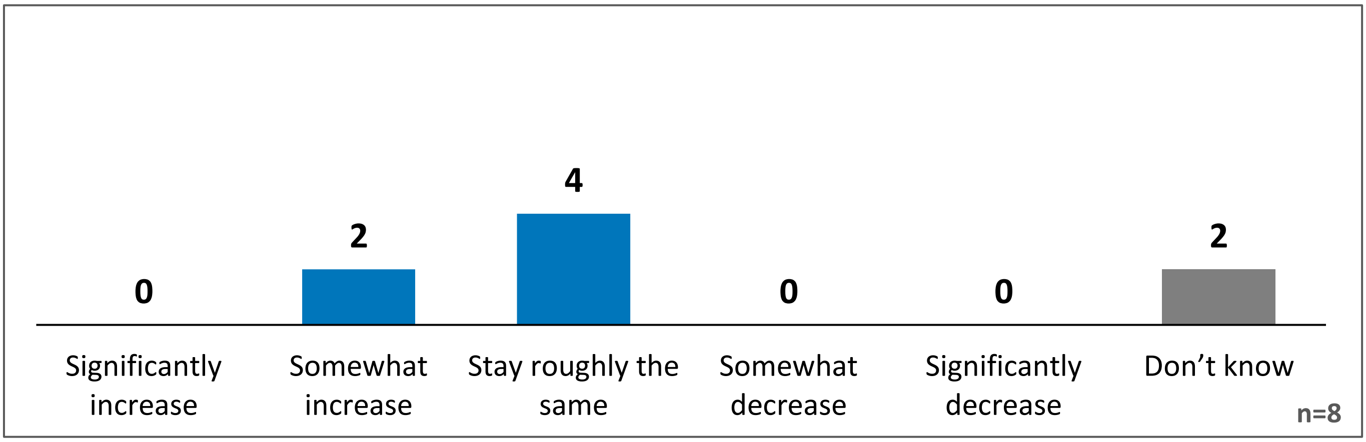


Impact on electricity usage

Q As a result of changes to Canada-US trade tariffs, has your organization's electricity usage increased, decreased, or stayed roughly the same relative to the pre-tariff period?



Q In the foreseeable future, do you anticipate your organization's electricity usage will increase, decrease, or stay roughly the same relative to today?



Building Understanding.

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INNOVATIVE RESEARCH GROUP

Manufacturing & Automotive Customer Online Survey

July 2025

ENTEGRUS®

INNOVATIVE
RESEARCH GROUP

Manufacturing & Automotive Customer

Online Survey Results

Online Survey
Introduction & Methodology

Introduction

Innovative Research Group Inc. (INNOVATIVE) was engaged by Entegrus Powerlines Inc. to assist in further engaging with its manufacturing and automotive customers in response to recent and potential Canada–US trade and tariff changes.

This survey was conducted to further augment the findings from Entegrus' earlier customer engagement efforts in support of its 2026 Cost of Service Rate Application.

Methodology

The **Automotive and Manufacturing Customer Survey** was sent to Entegrus manufacturing and automotive customers with an email address on file. Customers had an opportunity to complete the survey between **June 16th and July 8th, 2025**.

Each customer received a unique URL that could be linked back to their customer information.

In total, the manufacturing & automotive customer survey was sent to **39** customers from *engage@entegrus.com*. Reminder emails were sent on June 24th, June 26th, and July 2nd, 2025 to those who had not yet completed the survey.

Survey Completes

A total of **8** (unweighted) Entegrus manufacturing & automotive customers completed the online survey. This represents a response rate of 21%.

Sample Weighting

Due to the small sample size (n=8), the results are not weighted and are reported as frequencies. Results should be interpreted as directional.

INNOVATIVE RESEARCH GROUP

Uncertainty in business operations

Entegrus is gathering input from its largest customers to understand how recent and potential Canada–US trade and tariff changes are affecting your operations. Your feedback will help inform Entegrus' load forecasts.

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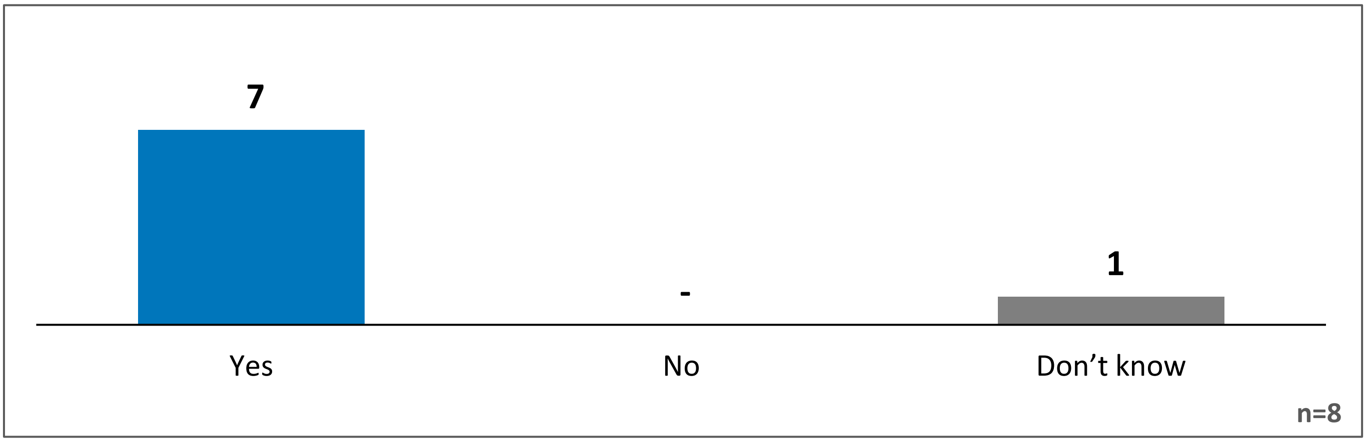

INNOVATIVE RESEARCH GROUP

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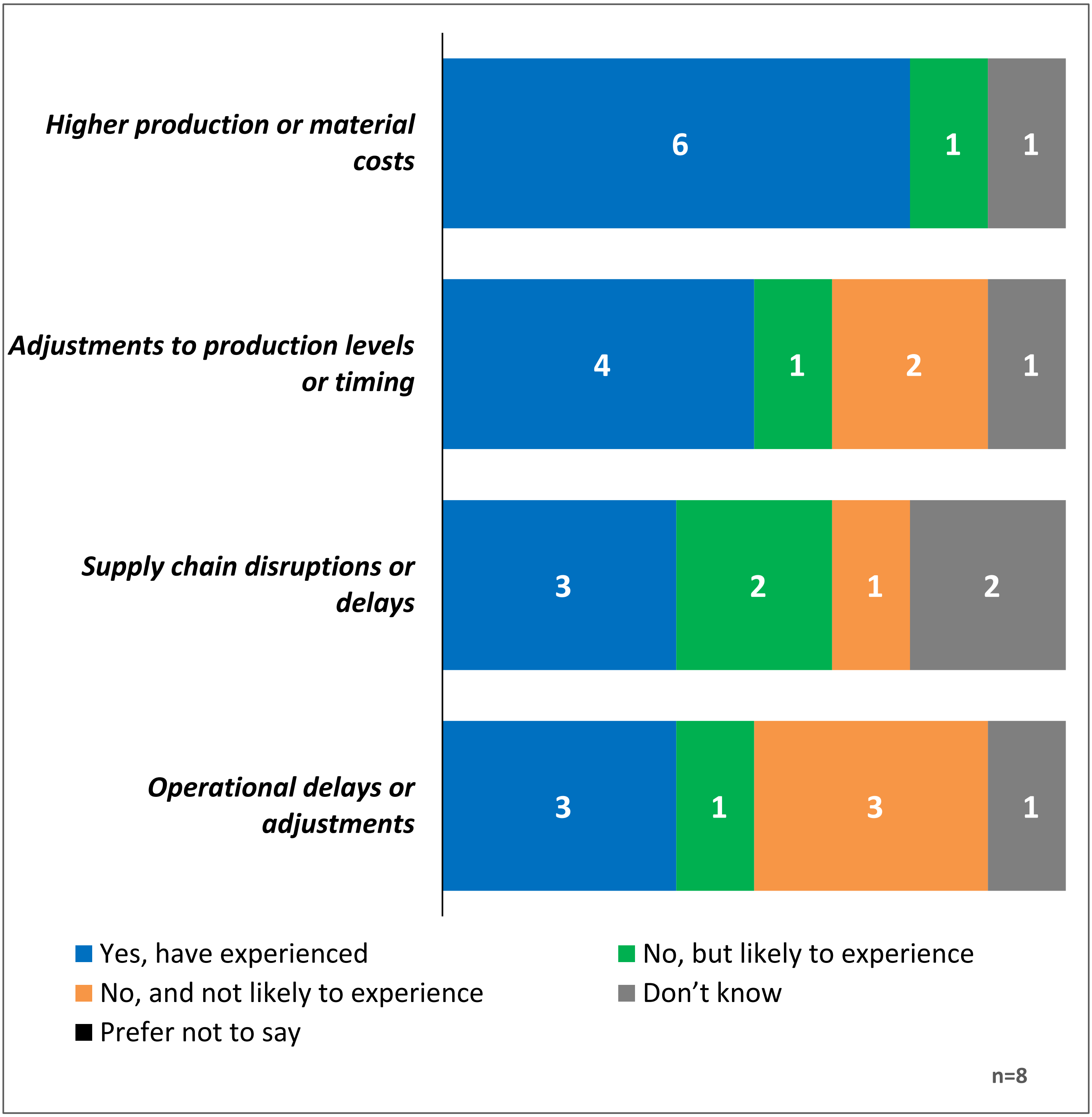

INNOVATIVE RESEARCH GROUP

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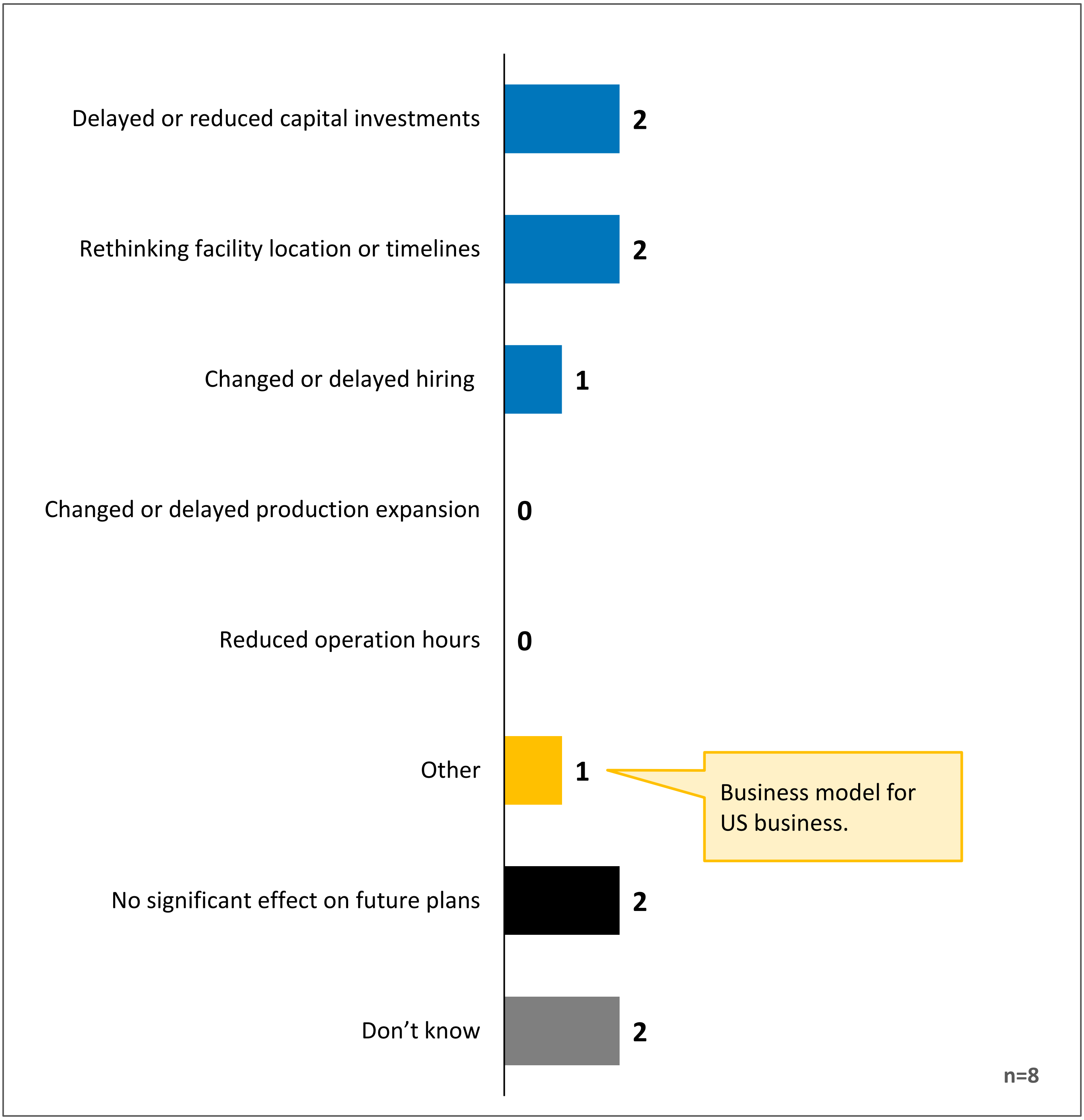

INNOVATIVE RESEARCH GROUP

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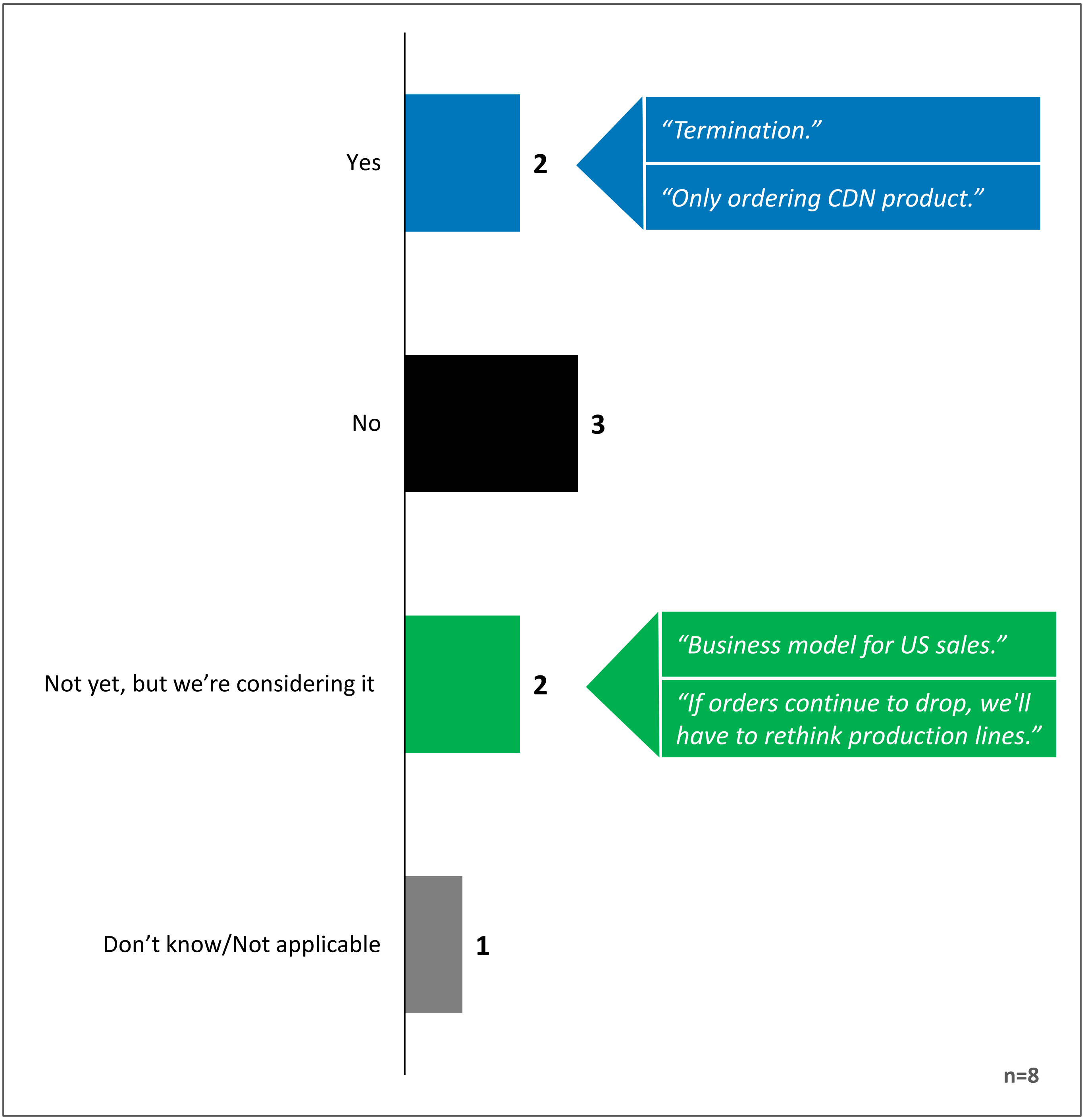

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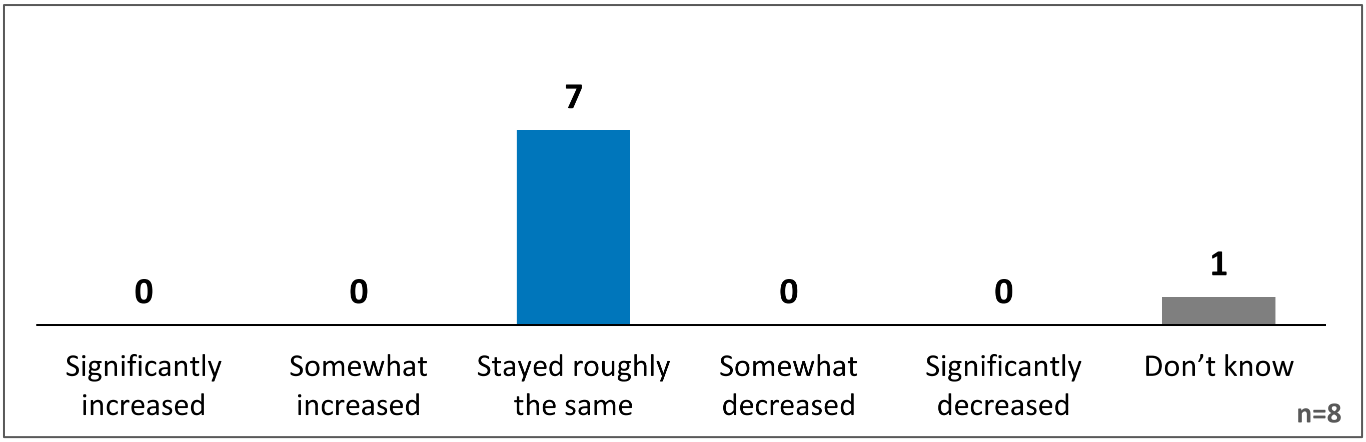

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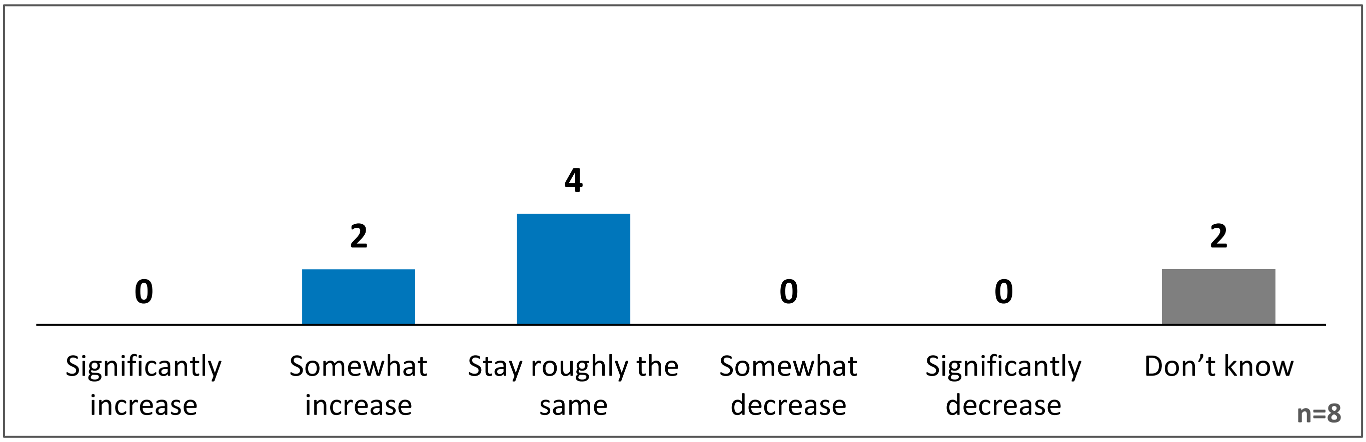

INNOVATIVE RESEARCH GROUP

INNOVATIVE
RESEARCH GROUP

Building Understanding.

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ATTACHMENT 1-H

Audited Financial Statements for 2024

Financial Statements of

ENTEGRUS POWERLINES INC.

December 31, 2024

Management's Responsibility for Financial Reporting

Entegrus Powerlines Inc.'s management is responsible for the preparation and presentation of the financial statements. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board of Directors exercises this responsibility through its Audit Committee. This committee is comprised of four directors of companies within the Entegrus group, two of whom are directors of the Entegrus Powerlines Inc. Board. This committee meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

MNP LLP, an independent external audit firm, has been appointed by the ultimate shareholders and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.

Jim Hogan
President and CEO

Chris Cowell
Chief Financial Officer
& VP Administration

TABLE OF CONTENTS

Independent Auditor's Report .... 1 - 2

Balance Sheet 3

Statement of Earnings and Comprehensive Income 4

Statement of Changes in Equity 5

Statement of Cash Flows 6

Notes to the Financial Statements .... 7 - 28

MNP

Independent Auditor's Report

To the Chairman and Board Members of
Entegrus Powerlines Inc.

Opinion

We have audited the financial statements of Entegrus Powerlines Inc. (the "Company"), which comprise the balance sheet as at December 31, 2024, and the statements of earnings and comprehensive loss, changes in equity and cash flows for the year then ended, and notes to the financial statements, including a summary of material accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2024, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards ("IFRS®").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS®, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

MNP LLP
Suite 700, 255 Queens Avenue, London ON, N6A 5R8 T: 519.679.8550 F: 519.679.1812

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

MNP LLP

Chartered Professional Accountants
Licensed Public Accountants
April 10, 2025

ENTEGRUS POWERLINES INC.
Balance Sheet
December 31, 2024

	2024	2023
ASSETS	**$**	$
CURRENT		
Cash and cash equivalents	**5,818,797**	3,152,246
Accounts receivable (Note 5)	**19,256,709**	17,101,825
Accounts receivable - unbilled revenue	**16,276,837**	15,045,823
Income taxes receivable	**-**	268,933
Inventories	**3,918,916**	3,357,685
Prepaid expenses	**1,400,508**	1,728,514
	46,671,767	40,655,026
NON-CURRENT		
Property, plant and equipment (Note 6)	**182,321,308**	169,791,078
Goodwill and intangible assets (Note 7)	**448,903**	519,997
Derivative instruments	**-**	1,449,329
	182,770,211	171,760,404
REGULATORY		
Regulatory debit balances (Note 8)	**16,799,251**	23,004,857
	246,241,229	235,420,287
LIABILITIES AND EQUITY		
CURRENT		
Accounts payable and accrued liabilities	**21,127,493**	19,407,194
Income taxes payable	**133,437**	-
Due to related parties (Note 12)	**10,313,332**	11,833,755
Current portion of long-term debt (Note 9)	**874,041**	4,118,133
Current portion of deferred revenue	**28,416**	22,786
Current portion of customer deposits	**1,544,349**	2,288,598
	34,021,068	37,670,466
NON-CURRENT		
Long-term debt (Note 9)	**87,044,452**	85,462,935
Employee future benefits (Note 10)	**2,998,054**	3,042,855
Derivative instruments	**2,473,282**	-
Non-current portion of deferred revenue	**22,791,026**	21,329,367
Non-current portion of customer deposits	**10,757,288**	9,021,787
Deferred income tax liability (Note 17)	**8,770,885**	8,820,802
	134,834,987	127,677,746
SHAREHOLDER'S EQUITY		
Share capital (Note 13)	**28,154,623**	28,154,623
Share premium	**41,232,836**	28,782,836
Hedging reserve	**(2,473,282)**	1,449,329
Retained earnings	**5,510,561**	5,880,959
	72,424,738	64,267,747
	241,280,793	229,615,959
REGULATORY		
Regulatory credit balances (Note 8)	**4,960,436**	5,804,328
	246,241,229	235,420,287

ENTEGRUS POWERLINES INC.
Statement of Earnings and Comprehensive Loss
Year Ended December 31, 2024

	2024	2023
	$	$
DISTRIBUTION REVENUE		
Residential	**81,447,846**	69,732,033
General service (Note 12)	**106,469,979**	99,455,784
Street lighting	**1,176,715**	1,110,788
	189,094,540	170,298,605
Retailer energy sales	**5,537,928**	5,513,092
	194,632,468	175,811,697
COST OF POWER	**164,449,223**	147,471,844
GROSS MARGIN ON SERVICE REVENUE	**30,183,245**	28,339,853
OTHER OPERATING REVENUE	**3,406,916**	3,825,950
	33,590,161	32,165,803
OPERATING AND MAINTENANCE EXPENSE		
Distribution	**7,551,009**	7,511,628
ADMINISTRATIVE EXPENSE		
Billing and collection	**4,666,448**	4,228,974
General administration	**5,825,404**	5,294,538
Interest	**5,167,979**	4,103,609
DEPRECIATION AND AMORTIZATION	**7,067,030**	6,901,801
	30,277,870	28,040,550
EARNINGS BEFORE INCOME TAXES	**3,312,291**	4,125,253
Provision for income taxes (Note 17)	**457,708**	181,028
NET EARNINGS	**2,854,583**	3,944,225
REGULATORY		
Net movement in regulatory balances, net of tax	**353,601**	1,828,065
NET EARNINGS AFTER NET MOVEMENTS IN REGULATORY BALANCES	**3,208,184**	5,772,290
OTHER COMPREHENSIVE INCOME (LOSS)		
Remeasurements of employee benefits (Note 10)	**21,418**	(78,950)
Cash flow hedges - effective portion of changes in fair value	**(3,922,611)**	(2,380,629)
COMPREHENSIVE (LOSS) INCOME	**(693,009)**	3,312,711

ENTEGRUS POWERLINES INC.
Statement of Changes in Equity
Year Ended December 31, 2024

	2024	2023
	$	$
SHARE CAPITAL	**28,154,623**	28,154,623
SHARE PREMIUM, BEGINNING OF YEAR	**28,782,836**	28,782,836
Conversion of debt to equity (Note 9)	**12,450,000**	-
SHARE PREMIUM, END OF YEAR	**41,232,836**	28,782,836
HEDGING RESERVE, BEGINNING OF YEAR	**1,449,329**	3,829,958
Other comprehensive loss:		
Cash flow hedges - effective portion of change in fair value	**(3,922,611)**	(2,380,629)
HEDGING RESERVE, END OF YEAR	**(2,473,282)**	1,449,329
RETAINED EARNINGS, BEGINNING OF YEAR	**5,880,959**	4,387,619
Net earnings after net movements in regulatory balances	**3,208,184**	5,772,290
Dividends paid	**(3,600,000)**	(4,200,000)
Other comprehensive income (loss):		
Remeasurements of employee benefits (Note 10)	**21,418**	(78,950)
RETAINED EARNINGS, END OF YEAR	**5,510,561**	5,880,959
TOTAL EQUITY	**72,424,738**	64,267,747

ENTEGRUS POWERLINES INC.
Statement of Cash Flows
Year Ended December 31, 2024

	2024	2023
	$	$
OPERATING ACTIVITIES		
Net earnings after net movement in regulatory balances	**3,208,184**	5,772,290
Adjustments for:		
Depreciation of property, plant and equipment	**7,409,866**	7,163,359
Amortization of intangible assets	**71,094**	70,692
Amortization of deferred revenue	**(609,278)**	(545,091)
Gain on disposal of property, plant and equipment	**(132,709)**	(31,779)
Employee future benefits	**(23,383)**	(15,545)
Contributions in aid of construction received	**2,070,937**	3,068,244
Net movements in regulatory balances	**5,311,797**	528,767
Change in non-current customer deposits	**1,735,501**	(43,165)
Change in non-cash working capital items (Note 14)	**(2,211,702)**	(2,133,605)
	16,830,307	13,834,167
INVESTING ACTIVITIES		
Proceeds on disposal of property, plant and equipment	**179,848**	96,227
Additions to property, plant and equipment	**(20,010,606)**	(17,446,796)
Additions to intangible assets	**-**	(61,282)
Loans to related parties	**(1,520,423)**	(4,830,561)
	(21,351,181)	(22,242,412)
FINANCING ACTIVITIES		
Advances from long-term debt	**88,000,000**	9,500,000
Repayment of long-term debt	**(77,212,575)**	(1,395,757)
Dividends paid	**(3,600,000)**	(4,200,000)
	7,187,425	3,904,243
NET CHANGE IN CASH AND CASH EQUIVALENTS	**2,666,551**	(4,504,002)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**3,152,246**	7,656,248
CASH AND CASH EQUIVALENTS, END OF YEAR	**5,818,797**	3,152,246

See Note 14 for supplemental cash flow information

1. NATURE OF OPERATIONS

Incorporation and merger

Entegrus Powerlines Inc. ("EPI" or "the Company") is incorporated under the *Business Corporations Act (Ontario).* In 2018, EPI and a company under common control, St. Thomas Energy Inc. ("STEI"), merged to continue as Entegrus Powerlines Inc.

The address of the Company's registered office is 320 Queen Street, Chatham, Ontario.

The Company is wholly-owned by Entegrus Inc. ("EI"), which is owned 71.49% by the Municipality of Chatham-Kent ("the Municipality"), 20.57% by the City of St. Thomas, and 7.94% by Corix Infrastructure Inc. The principal activity of the Company is to distribute electricity to customers within the Municipality of Chatham-Kent, Middlesex County, the County of Elgin and the City of St. Thomas, under a licence issued by the Ontario Energy Board ("OEB").

2. REGULATION

Rate-regulated entity

The Company is a regulated Local Distribution Company ("LDC") and has an electricity distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue an electricity distribution licence which must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity;
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return;
- Global Adjustment – The difference between the rate paid to regulated and contracted electricity generators and the spot market price;
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by the Company in respect of the transmission of electricity from generating stations to the local areas; and,
- Wholesale Market Services Charge – The wholesale market services charge represents the cost of services provided by the Independent Electricity System Operator ("IESO") to operate the wholesale electricity market and maintain the reliability of the power grid.

2. REGULATION (continued)

Rate-regulated entity (continued)

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

Market-based rate of return

The OEB approved rates in the legacy EPI service area effective May 1, 2016, which resulted in approved rates that include a 9.19% rate of return on equity rebased at 2016 test year levels. The rate of return of 9.19% was in accordance with the OEB's cost of capital parameters at that time.

The OEB approved rates in the legacy STEI service area effective January 1, 2015, which resulted in approved rates that include a 9.30% rate of return on equity rebased at 2015 test year levels. The rate of return of 9.30% was in accordance with the OEB's cost of capital parameters at that time.

Incentive Rate Mechanism

Between rate basing years, the OEB regulates the rates of the Company under an Incentive Rate Mechanism ("IRM") regime. The process includes a mechanistic approach to establishing rates with a rate rebasing (using a cost-of-service methodology) normally every five years. In conjunction with the approval of the merger of EPI and STEI, the OEB approved an extension of the IRM period through 2025. The IRM rate setting process provides an increase in rates for inflationary cost, partially offset by expected productivity and efficiency gains established by the OEB.

Regulatory balances

Electricity distributors are required to reflect certain prescribed amounts on their balance sheet until the manner and timing of distribution is determined by the OEB. Examples of these amounts include:

- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- Costs incurred related to changes in the OEB's Cost Assessment Model; and,
- Tax savings related to the accelerated investment incentive and immediate expensing incentive programs introduced by the Government of Canada in 2018 and 2021, respectively.

3. BASIS OF PREPARATION

Statement of compliance

The Company's financial statements have been prepared in accordance with IFRS as adopted by the International Accounting Standards Board ("IASB") and interpretations as issued by the IFRS Interpretations Committee ("IFRIC") of the IASB. The financial statements were approved by the Board of Directors and authorized for issue on April 10, 2025.

Basis of measurement

The financial statements have been prepared on the historical cost basis, except for the derivative instruments, which are measured at fair value.

Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Company's functional currency.

Use of estimates and judgments

The preparation of the financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Significant accounting estimates and assumptions may result in material adjustments to the carrying amount of assets and liabilities in the next financial year. Financial statement items requiring the use of management estimates include:

- Accounts receivable and distribution revenue – measurement of unbilled revenue;
- Goodwill – determination of cash-generating units ("CGUs") for impairment testing;
- Derivative instruments – fair value measurement; and,
- Employee future benefits – measurement of accrued benefit liability.

4. MATERIAL ACCOUNTING POLICIES

The accounting principles set out below have been applied consistently to all periods presented in these financial statements. These accounting policies are consistent with those set forth in the *Accounting Procedures Handbook for Electricity Distributors* ("APH") issued by the OEB under the authority of the *Ontario Energy Board Act, 1998*.

Regulation and regulatory balances

The Company is regulated under an electricity distribution licence by the OEB and any rate adjustments require OEB approval. All activities between the Company and its affiliates must adhere to the Affiliate Relationship Code issued by the OEB.

In January 2014, the IASB issued IFRS 14, *Regulatory Deferral Accounts*, as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous generally accepted accounting principles ("GAAP"). Regulatory balances provide useful information about the Company's financial position, financial performance and cash flows. IFRS 14 will remain in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

The Company has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the APH. Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding the Company's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on the Company's balance sheet, and they represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the disposition of these balances are assessed to no longer be probable based on management's judgments, the balances will be recorded in the Company's statement of earnings and comprehensive income in the period when the assessment is made. Regulatory balances that do not meet the definition of an asset or liability under any other IFRS are segregated on the balance sheet, and on the statement of earnings and comprehensive income. The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

4. MATERIAL ACCOUNTING POLICIES (continued)

Inventories

Inventories consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

Property, plant and equipment

Property, plant and equipment are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

Distribution assets:	
Distribution station equipment	15 – 45 years
Distribution system – overhead	30 – 60 years
Distribution system – underground	30 – 55 years
Distribution transformers	35 – 45 years
Distribution meters	25 years
System supervisory equipment	20 years
Automated mapping	15 years
Services	40 – 50 years
Smart meters	15 years
Buildings	20 – 50 years
Equipment and other:	
General office equipment	10 years
Computer hardware	3 – 5 years
Computer software	3 – 10 years
Rolling stock	7 – 15 years
Tools	10 years
Non-regulated generation assets	25 years

The Company recognizes work in process for larger capital projects that are not in service at the end of the year. When the capital projects are completed, they are transferred to the appropriate property, plant and equipment account. Depreciation of these assets will begin when they are available for use.

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. Contributions received are recorded as deferred revenue and recognized as revenue on a straight-line basis over the useful lives of the related assets.

Goodwill

Goodwill represents the excess of purchase price over fair value of the net identifiable assets of acquired businesses.

4. MATERIAL ACCOUNTING POLICIES (continued)

Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable. Cost is comprised of directly attributable expenditures such as labour, legal, and consulting costs. Amortization is recorded on a straight-line basis over a five-year useful life.

Impairment of non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Goodwill is tested for impairment annually or more frequently when an event or circumstance occurs that indicates that goodwill might be impaired.

For impairment testing, assets are grouped together into CGUs, which are defined as the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows from other assets or groups of assets. Goodwill arising from a business combination is allocated to the CGUs or group of CGUs that are expected to benefit from the synergies of the combination.

The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs of disposal. Value in use is based on the estimated future cash flows, discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset or CGU.

An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of electricity bills. Deposits that are refundable to customers on demand are classified as a current liability. Interest on deposits is paid at a rate of prime less 200 basis points.

Employment benefits other than pension

The Company provides its current and retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The cost of these benefits is actuarially determined annually as at December 31. The cost is determined using the projected unit credit method and assumptions including interest rates, salary escalation, retirement ages of employees, mortality rates, and health care costs. Remeasurements of the net defined benefit liability, which include actuarial gains and losses resulting from experience adjustments and changes in actuarial assumptions, are recognized in other comprehensive income as they arise without recycling through profit or loss in subsequent periods.

4. MATERIAL ACCOUNTING POLICIES (continued)

Deferred revenue

Deferred revenue is comprised of contributions in aid of construction received from third parties and conservation program funding advances received from the IESO.

Revenue recognition and cost of power

Distribution revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power to distribute are charged to regulatory assets or liabilities.

Income taxes

Under the *Electricity Act, 1998*, the Company is required to make payments-in-lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are recorded in accordance with the rules for computing income taxes and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporation Tax Act* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations.

The Company uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. The Company recognizes deferred tax assets and liabilities for future tax consequences of events that have been included in the financial statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheet and their respective tax basis, using the tax rates enacted or substantively enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations, and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to, or recovered from, customers through future electricity distribution rates. A gross-up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit balances.

Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

4. MATERIAL ACCOUNTING POLICIES (continued)

Financial instruments (continued)

Classification

Cash and cash equivalents	FVTPL
Accounts receivable	Amortized cost
Derivative instruments	Designated in a hedging relationship
Accounts payable and accrued liabilities	Other financial liabilities
Due to related parties	Other financial liabilities
Current portion of customer deposits	Other financial liabilities
Current portion of long-term debt	Other financial liabilities
Long-term debt	Other financial liabilities
Non-current portion of customer deposits	Other financial liabilities

Financial assets at FVTPL

These assets are subsequently measured at fair value. Net gains and losses, including any interest or dividend income, are recognized in profit or loss.

Amortized cost

Subsequent to initial recognition, these assets are accounted for at amortized cost using the effective interest method.

Derivative instruments

The Company holds derivative financial instruments to hedge its interest rate risk exposure. These derivatives are designated and effective hedging instruments, and as such, they are accounted for using hedge accounting.

Other financial liabilities

Subsequent to initial recognition, other financial liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Effective interest method

The Company uses the effective interest method to recognize interest income or expense which includes transaction costs or fees, premiums or discounts earned or incurred for financial instruments.

Financial assets and liabilities are offset and the net amount is presented in the balance sheet when, and only when, the Company has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

4. MATERIAL ACCOUNTING POLICIES (continued)

Financial instruments (continued)

Fair value measurements are established based on the following hierarchy that categorizes the inputs to valuation techniques:

Level 1	Fair value measurement based on quoted prices (unadjusted) observable in active markets for identical assets or liabilities
Level 2	Fair value measurement using inputs other than quoted market prices included within Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices)
Level 3	Fair value measurement using inputs that are not based on observable market date (unobservable inputs)

Hedge accounting

An item may only be designated in a hedging relationship if changes in fair value of the hedging item are expected to offset virtually all changes in fair value of the hedged item attributable to the hedged risk. This offsetting must be expected at inception of the hedge and throughout the hedging period.

The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives and strategy for undertaking various hedging transactions. The Company also documents and assesses, both at hedge inception and on an ongoing basis, whether the derivative financial instruments that are used in hedging transactions are highly effective in offsetting expected changes in the hedged items attributable to the hedged risk, which occurs when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and,
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Company actually hedges and the quantity of the hedging instrument that the Company actually uses to hedge that quantity of the hedged item.

The Company designates interest rate swap contracts as cash flow hedges of interest rate variability. In a cash flow hedging relationship, the change in value of the effective portion of the derivative is recognized in other comprehensive income. In contrast, the change in value of the ineffective portion of the derivative is recognized directly in profit or loss.

Hedge accounting is discontinued prospectively if the hedging instrument or hedged item is terminated or sold, or if it is determined that the hedging instrument is no longer effective.

4. MATERIAL ACCOUNTING POLICIES (continued)

Standards issued but not yet effective

Certain new or amended accounting standards have been published that are effective for annual periods beginning on or after January 1, 2025, with earlier application permitted; however, the Company has not early adopted the new or amended standards in preparing these financial statements.

Amendments to the Classification and Measurement of Financial Instruments (Amendments to IFRS 9 and IFRS 7)

In July 2023, the IASB issued amendments to IFRS 9 and IFRS 7 to clarify and enhance guidance on the derecognition and classification of financial instruments, and to introduce new disclosure requirements. Key changes include:

- Derecognition of financial liabilities: Entities may deem a liability settled before the settlement date when cash is transferred via an electronic payment system, if certain criteria are met.
- Classification of financial assets: Clarifications are provided on assessing whether cash flows are consistent with a basic lending arrangement, including guidance on non-recourse features and contractually linked instruments.
- Disclosures: New requirements include disclosing gains/losses on equity instruments designated at fair value through OCI, and information about contractual terms that could change the timing or amount of cash flows due to contingent events unrelated to basic lending risks and costs.

The amendments are effective for annual reporting periods beginning on or after January 1, 2026, with early application permitted (either in full or only for the classification amendments). The adoption of these amendments is not expected to have a significant impact on the Company's financial statements.

Presentation and Disclosure in Financial Statements (IFRS 18)

IFRS 18 replaces IAS 1, introducing new requirements for the presentation and disclosure of financial statements to enhance comparability and transparency. The standard mandates a structured format for the statement of profit or loss, requiring classification of income and expenses into defined categories: operating, investing, financing, income taxes, and discontinued operations. It also introduces mandatory subtotals, including operating profit or loss and profit or loss before financing and income taxes.

Additionally, IFRS 18 requires entities to disclose Management-Defined Performance Measures ("MPMs"), which are subtotals of income and expenses used in public communications, along with a reconciliation to IFRS-defined amounts. The amendments also introduce new principles for aggregation and disaggregation of financial statement items and revise the presentation of the statement of cash flows.

The standard is effective for annual reporting periods beginning on or after January 1, 2027, with early application permitted. The adoption of IFRS 18 is expected to have a moderate impact on the presentation and disclosure of the Company's financial statements, particularly in relation to the classification of income and expenses, the use of subtotals, and the additional disclosure requirements. The Company is currently assessing the full extent of the impact.

4. MATERIAL ACCOUNTING POLICIES (continued)

Standards issued but not yet effective (continued)

Subsidiaries without Public Accountability: Disclosures (IFRS 19)

IFRS 19 introduces reduced disclosure requirements for subsidiaries that do not have public accountability, while maintaining full compliance with the recognition, measurement, and presentation requirements of IFRS Accounting Standards. The standard applies to subsidiaries whose parent prepares consolidated financial statements in accordance with IFRS. The objective is to simplify financial reporting for eligible subsidiaries by reducing the volume and complexity of disclosures, thereby lowering compliance costs while preserving transparency.

The standard is applied voluntarily and allows subsidiaries to provide streamlined financial statement disclosures tailored to the needs of their financial statement users. IFRS 19 does not modify the accounting treatments prescribed by other IFRS standards but instead focuses on reducing the disclosure burden for qualifying entities.

IFRS 19 is effective for annual periods beginning on or after January 1, 2027, with early application permitted. The adoption of IFRS 19 is not expected to have a significant impact on the Company's financial statements.

5. ACCOUNTS RECEIVABLE

	2024	2023
	$	$
Electrical energy	**15,457,571**	14,169,820
Other	**4,613,206**	3,854,148
	20,070,776	18,023,968
Allowance for doubtful accounts	**(814,067)**	(922,143)
Net accounts receivable	**19,256,709**	17,101,825

6. PROPERTY, PLANT AND EQUIPMENT

	Distribution assets	Land and buildings	Equipment and other	**Total**
	$	$	$	**$**
Cost or deemed cost				
Balance at January 1, 2023	179,642,469	10,793,499	17,988,474	**208,424,442**
Additions	15,721,850	154,189	1,991,675	**17,867,714**
Disposals and retirements	-	(72,730)	(37,870)	**(110,600)**
Balance at December 31, 2023	195,364,319	10,874,958	19,942,279	**226,181,556**
Additions	16,936,044	525,400	2,977,685	**20,439,129**
Disposals and retirements	(50,149)	(93,140)	(288,087)	**(431,376)**
Balance at December 31, 2024	212,250,214	11,307,218	22,631,877	**246,189,309**
Accumulated depreciation				
Balance at January 1, 2023	33,874,776	2,616,011	12,361,566	**48,852,353**
Depreciation	5,657,291	296,572	1,632,144	**7,586,007**
Disposals and retirements	(1,731)	(9,263)	(36,888)	**(47,882)**
Balance at December 31, 2023	39,530,336	2,903,320	13,956,822	**56,390,478**
Depreciation	5,934,526	298,606	1,605,257	**7,838,389**
Disposals and retirements	(2,619)	(93,140)	(265,107)	**(360,866)**
Balance at December 31, 2024	45,462,243	3,108,786	15,296,972	**63,868,001**
Carrying amount				
Balance at December 31, 2023	155,833,983	7,971,638	5,985,457	169,791,078
Balance at December 31, 2024	**166,787,971**	**8,198,432**	**7,334,905**	**182,321,308**

The Company has recognized work in process of $1,120,516 for capital projects that were not available for use at December 31, 2024 (2023 - $60,132).

7. GOODWILL AND INTANGIBLE ASSETS

	Goodwill	Intangible Assets	**Total**
	$	$	**$**
Balance at January 1, 2023	367,304	162,103	**529,407**
Additions	-	61,282	**61,282**
Amortization	-	(70,692)	**(70,692)**
Balance at December 31, 2023	367,304	152,693	**519,997**
Amortization	-	(71,094)	**(71,094)**
Balance at December 31, 2024	367,304	81,599	**448,903**

For the purposes of impairment testing, all of the Company's goodwill has been allocated to its regulated operations. The recoverable amount was based on fair value less costs of disposal. Fair value was estimated by applying an industry-specific valuation multiple to regulated rate base. The valuation multiple, which represents a key assumption in the determination of fair value, was determined by referencing recent enterprise acquisition activity in the Ontario electricity distribution industry. At December 31, 2024, the recoverable amount of the Company's regulated operations exceeded its carrying amount.

8. REGULATORY BALANCES

Regulatory balances arise as a result of the rate-making process. Regulatory debit balances represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory credit balances represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process.

	January 1, 2024	Balances arising in the period	Recovery / reversal	**December 31, 2024**
	$	$	$	**$**
Regulatory debit balances				
Deferred income taxes	11,842,064	-	(1,965,055)	**9,877,009**
Energy cost variances	8,257,467	2,273,992	(5,628,343)	**4,903,116**
Other regulatory debit balances	1,177,068	-	(1,177,068)	**-**
Balances to be recovered	1,728,258	6,804,808	(6,513,940)	**2,019,126**
	23,004,857	9,078,800	(15,284,406)	**16,799,251**
Regulatory credit balances				
Other regulatory credit balances	2,783,066	1,071,246	-	**3,854,312**
Deferred tax liability associated with regulatory balances	3,021,262	-	(1,915,138)	**1,106,124**
	5,804,328	1,071,246	(1,915,138)	**4,960,436**

8. REGULATORY BALANCES (continued)

	January 1, 2023	Balances arising in the period	Recovery / reversal	**December 31, 2023**
	$	$	$	**$**
Regulatory debit balances				
Deferred income taxes	10,609,368	1,232,696	-	**11,842,064**
Energy cost variances	10,332,222	2,826,724	(4,901,479)	**8,257,467**
Other regulatory debit balances	392,744	1,177,068	(392,744)	**1,177,068**
Balances to be recovered	509,304	5,294,223	(4,075,269)	**1,728,258**
	21,843,638	10,530,711	(9,369,492)	**23,004,857**
Regulatory credit balances				
Other regulatory credit balances	2,325,776	(170,840)	628,130	**2,783,066**
Deferred tax liability associated with regulatory balances	3,211,906	(190,644)	-	**3,021,262**
	5,537,682	(361,484)	628,130	**5,804,328**

Regulatory debit and credit balances

a) Deferred income taxes

This balance represents the amount expected to be recovered/refunded in rates arising from temporary differences in the recognition of deferred income tax liabilities/assets (see Note 17).

b) Energy cost variances

These accounts represent the variance between the revenue collected using OEB approved rates for the non–competitive components of energy and the corresponding cost of these non-competitive charges. The net amount of these variances is held as a regulatory debit or credit balance, based on the expectation that the amounts will ultimately be approved for disposition by the OEB.

c) Other regulatory balances

Other regulatory balances include various deferred amounts in connection with the Lost Revenue Adjustment Mechanism, changes in the OEB’s Cost Assessment Model, and tax savings related to the accelerated investment incentive and immediate expensing incentive programs introduced by the Government of Canada in 2018 and 2021, respectively.

d) Regulatory balances to be recovered/refunded

This balance represents the remaining amounts to be refunded to or recovered from ratepayers arising from dispositions that have been approved by the OEB.

9. LONG-TERM DEBT

	2024	2023
	$	$
Variable rate term instalment bank loan with variable interest rate exchanged for fixed interest rate of 4.267% via interest rate swap, maturing in 2054	**51,918,493**	-
Variable rate interest-only bank loan with variable interest rate exchanged for fixed interest rate of 4.263% via interest rate swap, maturing in 2054	**36,000,000**	-
Variable rate term instalment bank loans with variable interest rates exchanged for fixed interest rates via interest rate swaps:		
Fixed interest rate of 3.6% - repaid during 2024	**-**	15,113,560
Fixed interest rate of 3.677% - repaid during 2024	**-**	6,464,576
Fixed interest rate of 3.32% - repaid during 2024	**-**	4,639,244
Fixed interest rate of 2.41% - repaid during 2024	**-**	3,111,043
Fixed interest rate of 2.786% - repaid during 2024	**-**	2,748,064
Fixed interest rate of 4.049% - repaid during 2024	**-**	7,166,915
Fixed interest rate of 5.04% - repaid during 2024	**-**	4,864,340
Fixed interest rate of 4.96% - repaid during 2024	**-**	9,500,000
Note due to the Municipality of Chatham-Kent, bearing interest at 4.54% - repaid during 2024	**-**	23,523,326
Notes due to Entegrus Inc. bearing interest at 4.54% - converted to equity in 2024	**-**	12,450,000
	87,918,493	89,581,068
Less: Current portion of long-term debt	**874,041**	4,118,133
	87,044,452	85,462,935

In 2024, interest expense recognized relating to long-term debt was $3,842,907 (2023 - $3,300,633).

The bank loans are unsecured and under the terms of the loans, the Company is required to comply with the following financial covenants:

a) at the end of each fiscal year, the debt service coverage ratio is not less than 1.20:1; and
b) at the end of each fiscal quarter, the funded debt to capitalization ratio shall be no greater than 0.65:1.

The Company has complied with these covenants throughout the reporting period.

10. EMPLOYEE FUTURE BENEFITS

The Company measures its accrued benefit obligation as at December 31 of each year. The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2022, and the next required valuation will be as of December 31, 2025.

Information about the Company's accrued benefit liability is as follows:

	2024	2023
	$	$
Accrued benefit liability, beginning of year	**3,042,855**	2,979,450
Expense for the year		
Current service cost	**117,187**	107,005
Interest on obligation	**135,719**	141,564
Remeasurements in other comprehensive income	**(21,418)**	78,950
Employer contributions	**(276,289)**	(264,114)
Accrued benefit liability, end of year	**2,998,054**	3,042,855

The main actuarial assumptions employed for the valuation are as follows:

General inflation

Future inflation levels, as measured by changes in the Consumers Price Index ("CPI"), were assumed to be 2.5% annually after the valuation date.

Interest (discount) rate

The present value of the future benefits and the expense for the year ended December 31, 2024 were determined using a discount rate of 4.66% (2023 – 4.58%). This corresponds to the most recent OEB approved non-arm's length cost of debt rate.

Health and dental costs

Health costs were assumed to increase at 8% per year for 10 years after the valuation date, and then at the CPI rate plus 1% thereafter. Dental costs were assumed to increase at the CPI rate plus 1% per year after the valuation date.

11. PENSION AGREEMENT

The Company provides a pension plan for its employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company's contribution for employees' current service in 2024 was $1,449,169 (2023 - $1,307,313).

12. RELATED PARTY TRANSACTIONS

Municipality of Chatham-Kent

The Company provided the following services in the normal course of operations to the Municipality:

	2024	2023
	$	$
Energy (at commercial rates)	**6,093,870**	5,607,262
Billing and collection services - water/wastewater	**2,324,082**	2,278,514
Streetlight maintenance	**354,722**	294,987
	8,772,674	8,180,763

The Municipality provided administrative services in the normal course of operations to the Company. In 2024, the amount charged for these services was $163,177 (2023 - $164,202).

City of St. Thomas

The Company provided the following services in the normal course of operations to the City of St. Thomas:

	2024	2023
	$	$
Energy (at commercial rates)	**1,917,239**	1,792,139
Billing and collection services - water/wastewater	**378,027**	365,597
	2,295,266	2,157,736

12. RELATED PARTY TRANSACTIONS (continued)

Entegrus Services Inc.

Entegrus Services Inc. ("ESI") is wholly owned by EI. ESI provides data services in the normal course of operations to the Company. In 2024, the amount charged for these services was $102,000 (2023 – $102,000).

Related party transactions with ESI completed in the normal course of business were recorded at their exchange amounts.

Due to/from related parties

At December 31, 2024, the Company had the following balances due to/from related parties:

- an outstanding balance payable to EI in the amount of $147,664 (2023 – $9,447,444);
- an outstanding balance payable to the Municipality in the amount of $8,837,380 (2023 - $1,074,677); and,
- an outstanding balance payable to the City of St. Thomas in the amount of $1,328,288 (2023 – $1,311,634).

Compensation of key management personnel

Compensation of directors and other members of key management personnel was as follows:

	2024	2023
	$	$
Salaries, wages and other short-term benefits	**1,695,976**	1,476,040
Post-employment benefits	**142,410**	103,360
	1,838,386	1,579,400

13. SHARE CAPITAL

The share capital of the Company consists of the following:

Authorized
Unlimited common shares
Unlimited Class "A" preference shares
Unlimited Class "B" preference shares
Unlimited Class "C" preference shares

	2024	2023
	$	$
Issued		
2,000 common shares	**28,154,623**	28,154,623

14. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital items

	2024	2023
	$	$
Accounts receivable	**(2,131,513)**	(4,106,554)
Accounts receivable - unbilled revenue	**(1,231,014)**	678,002
Income taxes receivable/payable	**402,370**	272,627
Inventories	**(561,231)**	(510,704)
Prepaid expenses	**328,006**	(27,320)
Accounts payable and accrued liabilities	**1,720,299**	1,071,740
Current portion of deferred revenue	**5,630**	22,786
Current portion of customer deposits	**(744,249)**	465,818
	(2,211,702)	(2,133,605)

Income taxes of $55,339 (2023 – $238,760) and interest of $5,167,979 (2023 - $4,103,609) were paid during the year.

15. FINANCIAL INSTRUMENTS

Fair value

The Company's recognized financial instruments consist of cash and cash equivalents, accounts receivable, due from related parties, derivative instruments, accounts payable and accrued liabilities, due to related parties, customer deposits and long-term debt.

The fair values of cash and cash equivalents, accounts receivable, due from related parties, accounts payable and accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical.

Fair value measurement of the derivative instruments is determined on the basis of a discounted cash flow model using inputs that are based on observable market data (i.e., Level 2 inputs). Estimate of future floating-rate cash flows are based on quoted swap rates, future prices, and interbank borrowing rates. Estimated cash flows are discounted using a yield curve constructed from similar sources and which reflects the relevant benchmark interbank rate used by market participants for this purpose when pricing interest rate swaps.

In order to determine fair value of long-term debt, comparison was made to the approved interest rate from the OEB. The OEB approves the rate of return on the long-term debt portion of "Cost of Capital" for non-arm's length transactions. An interest rate of 4.66% has been approved by the OEB through the rate setting process for rates effective January 2025. Using the OEB approved non-arm's length cost of debt for 2025 of 4.66%, the fair value of long-term debt is $82,888,819.

15. FINANCIAL INSTRUMENTS (continued)

Credit risk

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing-based corporations that pose a significant increase in risk due to the current state of the economy as well as the future outlook for the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk to an acceptable level.

Interest rate risk

EPI is exposed to interest rate risk on interest-bearing debt. The Company manages its exposure to interest rate risk by ensuring that substantially all of its interest on debt is at a fixed rate. This is achieved partly by entering into fixed rate instruments and partly by borrowing at a floating rate and using interest rate swaps as hedges of the variability in cash flows attributable to movements in interest rates.

The Company determines the existence of an economic relationship between the hedging instrument and the hedged item based on the reference interest rates, maturities and notional amounts. In these hedge relationships, the main source of ineffectiveness is the effect of the counterparty’s and the Company’s own credit risk on the fair value of the swaps, which is not reflected in the change in the fair value of the hedged cash flows attributable to the change in interest rates.

Liquidity risk

EPI is exposed to liquidity risk related to its ability to fund its obligations as they become due. The Company monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. The Company has access to debt capital markets and monitors cash balances daily. The Company also manages its liquidity risk by ensuring that all of its interest on debt is at a fixed rate.

The following tables set out the contractual maturities (representing undiscounted contractual cash flows) of the Company’s financial liabilities:

At December 31, 2024	Less than 12 months	Between 1 and 5 years	Over 5 years	Total contractual cash flows
	$	$	$	$
Accounts payable and accrued liabilities	21,127,493	-	-	21,127,493
Due to related parties	10,313,332	-	-	10,313,332
Customer deposits	1,544,349	5,378,644	5,378,644	12,301,637
Long-term debt	4,610,599	18,442,396	151,264,975	174,317,970
Total	37,595,773	23,821,040	156,643,619	218,060,432

15. FINANCIAL INSTRUMENTS (continued)

Liquidity risk (continued)

At December 31, 2023	Less than 12 months	Between 1 and 5 years	Over 5 years	Total contractual cash flows
	$	$	$	$
Accounts payable and accrued liabilities	19,407,194	-	-	19,407,194
Due to related parties	11,833,755	-	-	11,833,755
Customer deposits	2,288,598	4,510,894	4,510,894	11,310,385
Long-term debt	5,339,701	21,358,804	143,926,467	170,624,972
Total	38,869,248	25,869,698	148,437,361	213,176,306

16. CAPITAL DISCLOSURES

The Company’s main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC; and
- maintain a capital structure comparable for regulated activities as approved by the OEB’s deemed debt-to-equity structure in our rates.

As at December 31, 2024, the Company’s definition of capital includes Shareholder’s Equity and Long-Term Debt, the latter of which is comprised of the current and long-term portions of bank loans and notes payable. This definition has remained unchanged from December 31, 2023. As at December 31, 2024, shareholder’s equity amounts to $72,424,738 (2023 - $64,267,747) and long-term debt amounts to $87,918,493 (2023 - $89,581,068).

In 2024, the capital structure approved by the OEB in rates was 40% Equity, 56% Long-Term Debt and 4% Short-Term Debt. The OEB-approved capital structure is unchanged from 2023. The Company’s 2024 actual capital structure was 45% Equity (2023 - 42%) and 55% Long-Term Debt (2023 - 58%).

17. INCOME TAXES

The reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income tax is as follows:

	2024	2023
	$	$
Net earnings after net movements in regulatory balances, before income tax	**3,665,892**	5,953,318
Statutory income tax rate	**26.50%**	26.50%
Statutory income tax rate applied to earnings	**971,461**	1,577,629
Increase / (decrease) resulting from:		
Deferred income taxes transferred from (to) regulatory debit balances	**1,965,055**	(1,232,696)
Temporary differences between accounting and tax basis of assets and liabilities	**(1,978,444)**	206,156
Permanent differences	**8,951**	8,232
Effect of loss carryovers used	**(509,315)**	(378,293)
Provision for (recovery of) income taxes	**457,708**	181,028
Effective rate of income tax	**12.49%**	3.04%

Deferred income taxes

The deferred income tax liability is comprised of the following:

	2024	2023
	$	$
Temporary differences related to:		
Property, plant and equipment	**(18,960,716)**	(17,647,080)
Employee future benefits	**1,080,931**	1,097,084
Derivative instruments	**891,728**	(522,547)
Non-current portion of deferred revenue	**8,217,173**	7,690,180
Unused tax losses	**-**	561,561
	(8,770,885)	(8,820,802)

18. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year’s presentation.

ATTACHMENT 1-I

Reconciliation of Audited Financial Statements to RRR Trial Balances

Entegrus Powerlines Inc.
RRR 2.1.13: Balance Sheet Reconciliation
Year Ending December 31, 2024

Statement	Balance Sheet			

Sum of G/L Balance				
OEB Class	F/S Line Item	USoA	Total	
01 Current Assets	A) Cash and Cash Equivalents	1005	$	5,811,724
		1010	$	7,073
	A) Cash and Cash Equivalents Total		**$**	**5,818,797**
	B) Accounts Receivable	1100	$	15,457,571
		1104	$	2,773,007
		1110	$	1,840,513
		1115	$	(0)
		1130	$	(814,381)
	B) Accounts Receivable Total		**$**	**19,256,709**
	C) Accounts Receivable - Unbilled Revenue	1120	$	16,276,837
	C) Accounts Receivable - Unbilled Revenue Total		**$**	**16,276,837**
	E) Inventories	1330	$	3,918,916
	E) Inventories Total		**$**	**3,918,916**
	F) Prepaid Expenses	1180	$	1,400,508
	F) Prepaid Expenses Total		**$**	**1,400,508**
01 Current Assets Total			**$**	**46,671,768**
08 Electric Plant in Service - Distribution Plant	A) Capital Assets	1611	$	8,292,223
		1805	$	201,708
		1808	$	682,915
		1820	$	2,058,682
		1830	$	63,137,616
		1835	$	27,373,122
		1840	$	11,709,172
		1845	$	29,991,850
		1850	$	30,673,471
		1855	$	15,623,392
		1860	$	24,347,307
		1905	$	1,439,713
		1908	$	8,480,790
		1915	$	985,126
		1920	$	3,379,105
		1930	$	8,301,582
		1940	$	1,647,886
		1980	$	1,412,217
		1990	$	4,007,344
		2055	$	1,120,516
		2075	$	983,002
		2105	$	(56,524,975)
		2180	$	(412,825)
		2120	$	(6,589,631)
	A) Capital Assets Total		**$**	**182,321,308**
08 Electric Plant in Service - Distribution Plant Total			**$**	**182,321,308**
05 Electric Plant in Service - Intangible Plant	B) Goodwill and Other Intangibles	1610	$	641,342
		2060	$	367,304
		2120	$	(559,743)
	B) Goodwill and Other Intangibles Total		**$**	**448,903**
05 Electric Plant in Service - Intangible Plant Total			**$**	**448,903**

Entegrus Powerlines Inc.
RRR 2.1.13: Balance Sheet Reconciliation
Year Ending December 31, 2024

Statement	Balance Sheet

Sum of G/L Balance			
OEB Class	F/S Line Item	USoA	Total
04 Other Assets And Deferred Charges	A) Regulatory Balances	1508	$ 125,681
		1511	$ 321,674
		1518	$ 137,263
		1548	$ 124,478
		1550	$ 1,134,055
		1551	$ (184,391)
		1555	$ (9,205)
		1568	$ 0
		1576	$ (95,665)
		1580	$ (1,134,180)
		1584	$ 2,018,589
		1586	$ 1,323,545
		1588	$ 437,823
		1589	$ 1,055,138
		1592	$ (4,301,667)
		1595	$ 2,114,790
		2350	$ 8,770,884
	A) Regulatory Balances Total		**$ 11,838,813**
04 Other Assets And Deferred Charges Total			**$ 11,838,813**
12 Current Liabilities	A) Accounts Payable and Accrued Liabilities	2205	$ (19,261,372)
		2220	$ (1,725,378)
		2268	$ (133,687)
		2292	$ (7,056)
	A) Accounts Payable and Accrued Liabilities Total		**$ (21,127,493)**
	B) Income Taxes Payable	2294	$ (133,437)
	B) Income Taxes Payable Total		**$ (133,437)**
	C) Due to Related Parties	1110	$ 2,231,949
		1200	$ (8,984,978)
		2240	$ (3,560,303)
	C) Due to Related Parties Total		**$ (10,313,332)**
	D) Current Portion of Long-Term Debt	2260	$ (874,041)
	D) Current Portion of Long-Term Debt Total		**$ (874,041)**
	E) Current Portion of Deferred Revenue	2425	$ (28,416)
	E) Current Portion of Deferred Revenue Total		**$ (28,416)**
	F) Current Portion of Customer Deposits	2210	$ (598,418)
		2220	$ (945,931)
	F) Current Portion of Customer Deposits Total		**$ (1,544,349)**
12 Current Liabilities Total			**$ (34,021,068)**
13 Non-Current Liabilities	A) Long-Term Debt	2520	$ (87,044,452)
	A) Long-Term Debt Total		**$ (87,044,452)**
	B) Employee Future Benefits	2306	$ (2,998,054)
	B) Employee Future Benefits Total		**$ (2,998,054)**
	C) Derivative Instruments	2320	$ (2,473,282)
	C) Derivative Instruments Total		**$ (2,473,282)**
	D) Long-Term Portion of Deferred Revenue	2440	$ (22,791,026)
	D) Long-Term Portion of Deferred Revenue Total		**$ (22,791,026)**
	E) Long-Term Portion of Customer Deposits	2335	$ (8,749,449)
		2340	$ (2,007,838)
	E) Long-Term Portion of Customer Deposits Total		**$ (10,757,288)**
	F) Deferred Income Taxes	2350	$ (8,770,884)

Entegrus Powerlines Inc.
RRR 2.1.13: Balance Sheet Reconciliation
Year Ending December 31, 2024

Statement	Balance Sheet

Sum of G/L Balance			
OEB Class	F/S Line Item	USoA	Total
13 Non-Current Liabilities	**F) Deferred Income Taxes Total**		**$ (8,770,884)**

Entegrus Powerlines Inc.
RRR 2.1.13: Balance Sheet Reconciliation
Year Ending December 31, 2024

Statement	Balance Sheet			

Sum of G/L Balance				
OEB Class	F/S Line Item	USoA	Total	
13 Non-Current Liabilities Total			**$**	**(134,834,986)**
16 Shareholders' Equity	A) Share Capital	3005	$	(28,154,623)
	A) Share Capital Total		**$**	**(28,154,623)**
	B) Share Premium	3010	$	(41,232,836)
	B) Share Premium Total		**$**	**(41,232,836)**
	C) Hedging Reserve	3040	$	2,473,282
	C) Hedging Reserve Total		**$**	**2,473,282**
	D) Retained Earnings	3045	$	(5,902,376)
		3049	$	3,600,000
		3046	$	(3,208,184)
	D) Retained Earnings Total		**$**	**(5,510,560)**
16 Shareholders' Equity Total			**$**	**(72,424,737)**

Entegrus Powerlines Inc.
RRR 2.1.13: Income Statement Reconciliation
Year Ending December 31, 2024

Statement	Income Statement		

Sum of G/L Balance OEB Class	F/S Line Item	USoA	Total
18 Revenues from Services - Distribution	**A) Distribution Revenue**	4080	$ (32,457,238.17)
	A) Distribution Revenue Total		**$ (32,457,238.17)**
	A) Energy Sales Revenue	4006	$ (50,726,453.17)
		4020	$ (2,216,621.97)
		4025	$ (559,379.07)
		4030	$ (36,528.39)
		4035	$ (69,287,491.43)
		4050	$ (681,248.34)
		4062	$ (8,141,015.48)
		4066	$ (13,026,942.33)
		4068	$ (9,574,105.19)
		4075	$ (2,071,713.33)
		4076	$ (315,803.57)
	A) Energy Sales Revenue Total		**$ (156,637,302.27)**
	B) Retail Energy Sales Revenue	4055	$ (5,537,928.34)
	B) Retail Energy Sales Revenue Total		**$ (5,537,928.34)**
18 Revenues from Services - Distribution Total			**$ (194,632,468.78)**
25 Other Power Supply Expenses	**A) Cost of Power**	4705	$ 94,328,409.58
		4707	$ 36,991,233.13
		4708	$ 8,141,015.48
		4714	$ 13,026,942.33
		4716	$ 9,574,105.19
		4750	$ 2,071,713.33
		4751	$ 315,803.57
	A) Cost of Power Total		**$ 164,449,222.61**
25 Other Power Supply Expenses Total			**$ 164,449,222.61**
20 Other Operating Revenues	**A) Other Revenue**	4082	$ (48,391.97)
		4084	$ (568.03)
		4086	$ (185,872.51)
		4205	$ (56,051.04)
		4210	$ (507,578.68)
		4220	$ (16,946.20)
		4225	$ (456,611.72)
		4235	$ (480,230.52)
		4245	$ (609,277.83)
		4305	$ 265,617.00
		4325	$ (6,285.26)
		4355	$ (136,139.16)
		4360	$ 3,430.01
		4375	$ (927,706.27)
		4380	$ 385,589.58
		4390	$ (62,546.28)
		4398	$ 738.00
		4405	$ (568,085.39)
	A) Other Revenue Total		**$ (3,406,916.27)**
20 Other Operating Revenues Total			**$ (3,406,916.27)**

Entegrus Powerlines Inc.
RRR 2.1.13: Income Statement Reconciliation
Year Ending December 31, 2024

Statement	Income Statement			

Sum of G/L Balance				
OEB Class	**F/S Line Item**	**USoA**	**Total**	
28 Distribution Expenses - Operation	**A) Operating and Maintenance Expense**	5005	$	1,167,562.88
		5010	$	136,509.33
		5016	$	106,449.99
		5017	$	121,558.45
		5020	$	149,735.13
		5025	$	5,252.20
		5035	$	12.00
		5040	$	218,843.97
		5045	$	264,267.30
		5055	$	23,657.14
		5065	$	228,123.19
		5070	$	25,169.12
		5075	$	5,407.13
		5105	$	1,145,716.74
		5114	$	138,576.86
		5120	$	213,445.87
		5125	$	625,900.58
		5130	$	380,339.40
		5135	$	193,659.42
		5145	$	8,711.92
		5150	$	77,229.52
		5155	$	309,114.46
		5160	$	76,270.14
		5170	$	2,110.57
		5175	$	388,893.70
		5410	$	14,643.06
		5510	$	17,826.99
		5620	$	505,690.31
		5630	$	187,727.24
		5645	$	213,964.69
		5646	$	95,576.78
		5665	$	24,295.76
		5675	$	727,079.27
		6105	$	298,460.72
	A) Operating and Maintenance Expense Total		**$**	**8,097,781.83**
28 Distribution Expenses - Operation Total			**$**	**8,097,781.83**
31 Billing and Collecting	**A) Billing and Collection Expense**	5305	$	882,383.01
		5315	$	2,554,663.53
		5320	$	(204,773.56)
		5335	$	347,645.32
		5340	$	1,086,530.55
	A) Billing and Collection Expense Total		**$**	**4,666,448.85**
31 Billing and Collecting Total			**$**	**4,666,448.85**
34 Administrative and General Expenses	**A) General Administration Expense**	5610	$	3,778,524.53
		5615	$	167,437.35
		5635	$	226,509.48
		5655	$	962,940.91
		6205	$	143,218.08
	A) General Administration Expense Total		**$**	**5,278,630.35**
34 Administrative and General Expenses Total			**$**	**5,278,630.35**
35 Depreciation and Amortization Expense	**A) Depreciation and Amortization**	5705	$	7,067,030.37
	A) Depreciation and Amortization Total		**$**	**7,067,030.37**
35 Depreciation and Amortization Expense Total			**$**	**7,067,030.37**

Entegrus Powerlines Inc.
RRR 2.1.13: Income Statement Reconciliation
Year Ending December 31, 2024

Statement	Income Statement		

Sum of G/L Balance OEB Class	F/S Line Item	USoA	Total
36 Interest Expense	**A) Interest Expense**	6005	$ 2,267,992.60
		6030	$ 2,074,286.72
		6035	$ 825,699.80
	A) Interest Expense Total		**$ 5,167,979.12**
36 Interest Expense Total			**$ 5,167,979.12**
37 Taxes	**A) Provision for Income Taxes**	6110	$ 457,708.07
	A) Provision for Income Taxes Total		**$ 457,708.07**
37 Taxes Total			**$ 457,708.07**
41 Other Comprehensive Income	**A) Other Comprehensive Income**	7005	$ 3,922,611.00
		7010	$ (21,418.00)
	A) Other Comprehensive Income Total		**$ 3,901,193.00**
41 Other Comprehensive Income Total			**$ 3,901,193.00**
Net Movement in Regulatory Balances	**A) Net Movement in Regulatory Balances**	4080	$ 1,504,614.00
		4210	$ 212,498.00
		4705	$ (2,273,992.00)
		5646	$ 11,487.00
		6205	$ 191,792.00
	A) Net Movement in Regulatory Balances Total		**$ (353,601.00)**
Net Movement in Regulatory Balances Total			**$ (353,601.00)**
Grand Total			**$ 693,008.15**

ATTACHMENT 1-J

Rating Agency Report

Entegrus Powerlines Inc.

April 30, 2025

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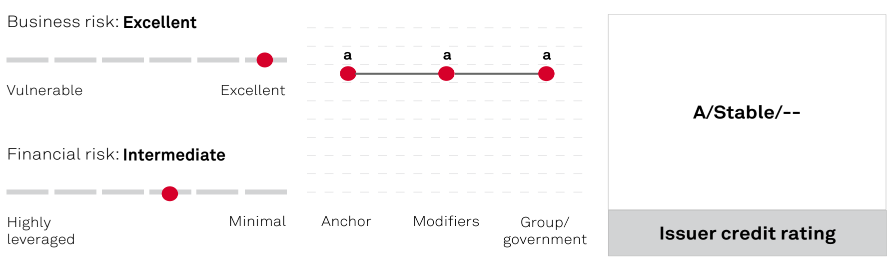
This report does not constitute a rating action.

Ratings Score Snapshot



Credit Highlights

Overview

Key strengths	Key risks
Low operational risk and regulated electricity distribution business with minimal exposure to nonregulated operations.	Limited geographic and regulatory diversity, with small operation scale serving about 63,000 customers in Southern Ontario.
Effective management of regulatory risk through the use of regulatory mechanisms supported by the Ontario Energy Board (OEB).	Negative discretionary cash flow leading to external funding needs.
Residentially focused customer base provides some stability to cash flow.	

We expect Entegrus Powerlines Inc. (EPI) to continue effectively managing its regulatory risk. We believe the company's essential electricity distribution operations will continue to benefit from the credit-supportive regulatory framework in the Canadian province of Ontario, which generally allows EPI to recover prudently incurred operating and capital expenses in a timely manner. Our assessment also incorporates EPI's use of revenue decoupling and fixed-rate distribution tariffs, which we view as key credit strengths. EPI currently operates under an incentive rate-setting mechanism, which establishes base rates for five years and forecasts its costs and sales volumes using a fixed return on equity. At the beginning of this year, EPI's request for a 3.60% increase was approved by the OEB. Customers with monthly consumption of 750 kilowatt-hours in the St. Thomas zone would experience a modest increase to their monthly bills, effective January 2025, while the Main rate zone would experience a decrease of $0.41 in their monthly bill, effective May 2025.

EPI’s small scale and lack of operational diversity is marginally offset by its favorable customer mix and credit-supportive regulatory environment. The company has a small customer base and lacks geographic and regulatory diversity. EPI serves about 63,000 customers, all in Ontario, which makes it reliant on its sole regulator, the OEB, to sustain its credit quality. While the company has a small customer base, it mostly comprises residential customers that are less sensitive to macroeconomic factors. Our assessment also considers parent Entegrus Inc.’s (EI) nonutility exposure (about 5% of consolidated EBITDA). These businesses include an equity investment in a wind farm and data centre operations. We view these businesses as having more risk than regulated utilities. However, we expect the company will not materially expand these businesses in relation to the overall consolidated company.

We assess EPI's financial risk profile as intermediate. This reflects our expectation that EPI will maintain stand-alone funds from operations (FFO) to debt of 13%-14% through 2027. Our forecast assumes capital spending of C$18 million-C$20 million annually and annual dividends averaging about C$3.5 million. Capital spending is largely focused on modernizing the system to improve reliability and safety as well as adding new capacity to serve customers in St. Thomas, which has a higher customer growth rate. We assess the financial risk profile using our low-volatility financial benchmark table, which reflects its mostly lower-risk, regulated electric distribution operations and effective management of regulatory risk.

Our projections do not consider the impact of tariffs and while the majority of the customers are residential, there could be some potential impact on consumption given exposure to auto suppliers who are part of its service territory. We continue to monitor the situation and potential impact on credit measures.

S&P Global Ratings believes there is a high degree of unpredictability around policy implementation by the U.S. administration and possible responses--specifically with regard to tariffs--and the potential effect on economies, supply chains, and credit conditions around the world. As a result, our baseline forecasts carry a significant amount of uncertainty. As situations evolve, we will gauge the macro and credit materiality of potential and actual policy shifts and reassess our guidance accordingly (see our research here: spglobal.com/ratings).

We believe EPI’s owners will continue to support the company. The Municipality of Chatham-Kent owns 72% of EI, the City of St. Thomas owns 20%, and Corix District Energy Holdings L.P. owns the remaining 8%. In December 2024, the company entered into a new loan agreement with TD to replace all its outstanding debt at that date, including repayment of Chatham-Kent’s $23.5 million note payable and obtaining a $10 million committed credit facility due 2027. We continue to believe the municipality will provide support to EI, if needed, given its role as a provider of essential service.

Outlook

The stable rating outlook on EPI reflects our expectation for predictable and stable cash flows from the utility's low-risk, regulated distribution business over the next two years. In our base-case scenario, we expect parent EI's consolidated FFO to debt to be 14%-15% throughout the forecast period.

Downside scenario

We could lower our rating on EPI over the next 24 months if:

- EI's consolidated financial measures weaken such that FFO to debt approaches 13%;
- EPI experiences a material adverse regulatory ruling; or
- EI's nonutility business increases to above 10% of consolidated EBITDA.

Upside scenario

While unlikely during the outlook period, we could raise our rating on EPI over the next 24 months if EI improves its financial measures such that FFO to debt is consistently above 20% without increasing business risk.

Our Base-Case Scenario

Entegrus Powerlines Inc.--Forecast summary

Period ending	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
	2024e	2025f	2026f	2027f
Adjusted ratios				
Debt/EBITDA (x)	5	5-6	5-6	5-6
FFO/debt (%)	13.9	13.5-14.0	13.5-14.0	13.0-14.0
FFO cash interest coverage (x)	3.3	4.0-4.5	4.0-4.5	4.0-4.5

All figures are adjusted by S&P Global Ratings, unless stated as reported. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

EPI, a wholly owned subsidiary of EI, is a Canadian utility in southwestern Ontario. EPI provides regulated electricity distribution to about 63,000 customers in Chatham-Kent, Middlesex County, the County of Elgin, and the City of St. Thomas under a license issued by the OEB. EI is majority-owned by the Municipality of Chatham-Kent (71.49%), with the remainder owned by the City of St. Thomas (20.57%) and Corix District Energy Holdings L.P. (7.94%).

Liquidity

We assess EPI's liquidity as adequate, with sources covering uses by 1.1x over the next 12 months. We also believe the company's net sources would remain positive even if the forecast consolidated EBITDA declined 10%. We believe EPI's use of regulatory mechanisms for cost recovery provides it with a manageable level of cash flow stability, even in times of economic stress, which supports our use of slightly lower thresholds to assess its liquidity. In addition, EPI has the ability to absorb high-impact, low-probability events, given the recently obtained $10 million credit facility due 2027. We also believe it could reduce its high capital spending (averaging about C$19 million annually through 2027) during stressful periods, which is indicative of a limited need for refinancing under such conditions. Overall, we believe EPI will likely be able to withstand adverse market circumstances over the next 12 months while maintaining sufficient liquidity to meet its obligations.

Principal liquidity sources

- Cash and liquid investments of about C$5.8 million as of Dec. 31, 2024;
- Estimated cash FFO of about C$13 million; and
- Committed credit facility availability of C$10 million as of Dec. 31, 2024.

Principal liquidity uses

- Debt maturities of about C$2.6 million;
- Capital spending of about C$20 million; and
- Dividends of about C$2.5 million.

Covenant Analysis

Requirements

As per its loan agreement, EPI is subject to maintain total debt to capitalization of below 65% and a debt service coverage ratio of less than 1.20x.

Compliance expectations

As of Dec. 31, 2024, EPI was in compliance with its covenants and we expect it will have sufficient cushion over our forecast period, given the stability of its regulated utility operations.

Group Influence

Under our group rating methodology, we consider EPI to be core to its ultimate parent, EI. This reflects our view that EPI is highly unlikely to be sold, is integral to the group's overall strategy, possesses a strong long-term commitment from senior management, and is closely linked to the parent's name and reputation. Our issuer credit rating on EPI is in line with our 'a' group credit profile for EI.

Rating Component Scores	
Foreign currency issuer credit rating	**A/Stable/--**
Local currency issuer credit rating	**A/Stable/--**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Intermediate**
Cash flow/leverage	Intermediate
Anchor	**a**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of April 30, 2025)*	
Entegrus Powerlines Inc.	
Issuer Credit Rating	A/Stable/--
Issuer Credit Ratings History	

Ratings Detail (as of April 30, 2025)*	
26-Apr-2024	A/Stable/--
11-May-2023	A/Negative/--
15-Jan-2019	A/Stable/--

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.