EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

2025 Cost of Service

Algoma Power Inc.
EB-2024-0007

1.1 TABLE OF CONTENTS

1.1.1 TABLE OF CONTENTS

1.2 INTRODUCTION AND EXECUTIVE SUMMARY

1.2.1 INTRODUCTION

Algoma Power Inc. ("API") is pleased to present its Cost of Service application (the "Application") for rates effective January 1, 2025. This application consists of the following Exhibits, and live Excel models in support of the evidence presented in this Application.

Exhibits:

- Exhibit 1: Administrative Documents
- Exhibit 2: Rate Base and DSP
- Exhibit 3: Revenues
- Exhibit 4: Operating Expenses
- Exhibit 5: Cost of Capital and Capital Structure
- Exhibit 6: Revenue Requirement
- Exhibit 7: Cost Allocation
- Exhibit 8: Rate Design
- Exhibit 9: Deferral and Variance Accounts

Models:

- API 2025 Benchmarking Forecast Model
- API 2025 Cost Allocation
- API 2025 PILs Workform
- API 2025 Rev Requirement Workform
- API 2025 RTSR Workform
- API 2025 Load Forecast Model
- API 2025 COS Checklist
- API 2025 DVA Continuity Schedule
- API 2025 GA Analysis Workform
- API 2025 Chapter 2 Appendices

- API 2025 Tariff Bill Impact Model (API Version)

All documents and models have been submitted to the OEB via the RESS filing system.

1.2.2 SUMMARY OF APPLICATION INTENDED FOR API CUSTOMERS

A brief, plain-language summary of the application is included as Attachment 1A. The summary will be posted as a stand-alone document on the OEB's website for review by the general public and be made available to customers of API via its website and social media. API has also included this summary as a stand-alone pdf file to aid in website posting of this document.

1.2.3 EXECUTIVE SUMMARY AND BUSINESS PLAN

Algoma Power Inc. ("API") has developed a Business Plan, included as Attachment 1B, to address the expectations of the OEB's *"Handbook for Utility Rate Applications"*, issued October 13, 2016.

Key elements of the Application and Business Plan are:

1) Identification of six strategic customer focused objectives that drive capital and O&M plans and related investments over the 2025-2029 period:
    a. Sustaining End of Life Asset Replacement
    b. Sustaining Vegetation Management
    c. Worker and Public Safety and Environmental Protection
    d. Reliability and Resiliency improving investments
    e. Preparing for the Energy Transition with long-term cost-effectiveness in mind;
    f. Flexible Approach to Emerging Technology and Public Policy
2) A Distribution System Plan ("DSP") with projects and programs aligned with the strategic objectives listed above;
3) API's goals for the 2025-2029 period are to implement its planned projects and programs that are aligned with the objectives identified above, and to meet or exceed all targets for performance metrics identified in the DSP and the Business Plan;
4) Enhanced customer engagement to ensure that the preferences of API's customers were identified and considered in determining the strategic objectives listed above;
5) Evaluation and forecasting of performance metrics that are consistent with the OEB's Renewed Regulatory Framework ("RRF");
6) 2025 Cost Allocation Study that features new load profiles based on API customer meter data.
7) Rate-setting approaches that are consistent with historical OEB-approved approaches to ensure alignment between OEB policies and the RRRP framework, as adjusted to address rate mitigation requirements.

1.3 ADMINISTRATIVE

1.3.1 CONTACT INFORMATION

Application contact information is as follows:

Applicant's Name:	Algoma Power Inc.
Applicant's Address:	1130 Bertie Street P.O. Box 1218 Fort Erie, Ontario L2A 5Y2 Phone: (905) 871-0330 Fax: (905) 994-2207
Physical Address:	251 Industrial Park Crescent Sault Ste. Marie, Ontario P6B 5P3
Applicant Primary Contact:	Oana Stefan Manager Regulatory Affairs Email: regulatoryaffairs@fortisontario.com Phone: (905) 871-0330 ext. 3271
Applicant's Counsel:	Michael Buonaguro 24 Humber Trail Toronto, Ontario M6S 4C1 Email: mikebuonaguro@me.com Phone: (416) 767-1666

1.3.2 CONFIRMATION OF INTERNET ADDRESS

The application will be posted on API's website address at www.algomapower.com and a message to that effect will be posted on the utility's , Facebook page (https://www.facebook.com/AlgomaPower/) and X site.

1.3.3 STATEMENT OF PUBLICATION

The persons affected by this Application are the ratepayers of API. It is impractical to set out their names and addresses because they are too numerous.

API recommends that the Notice of Application (the "Notice") be published in The Sault Star, which is the English-language newspaper having the highest paid circulation in API's service territory. API also recommends that the Notice be published in the Wawa Algoma News Review.

1.3.4 LEGAL APPLICATION

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

AND IN THE MATTER OF an application by Algoma Power Inc. for an Order or Orders, pursuant to section 78 of the Act, approving or fixing just and reasonable distribution rates effective January 1, 2025;

API is a licensed distributor of electricity under distribution licence ED-2009-0072 issued by the Ontario Energy Board (the "OEB" or the "Board") under the Ontario Energy Board Act, 1998 (the "Act").

This Application is made in accordance with the Chapter 2 (Cost of Service) and Chapter 5 (Consolidated Distribution System Plan) of the Board's Filing Requirements for Electricity Distribution Rate Applications dated December 15, 2022 (the "Filing Requirements"), except as noted in Section 1.3.11. Through this filing, API is applying to the Board for the following Orders:

1) Approval to charge distribution rates effective January 1, 2025 to recover a service revenue requirement of $35,768,551, which includes a revenue deficiency of $3,193,707 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8;
2) Approval of the addition of the #4 Circuit advancement cost into the 2025 Test Year rate base, as outlined in Exhibit 2;
3) Approval of the 2025 RRRP Funding amount payable to API, as described in Exhibit 8 (subject to update with the OEB's issuance of the 2025 RRRP adjustment factor);
4) Approval to adjust the Retail Transmission Rates as calculated in Exhibit 8;
5) Approval of the proposed loss factors as calculated in Exhibit 8;

6) Approval of the rate riders for disposition of the Deferral and Variance Accounts, as detailed in Exhibit 9;
7) Approval for two proposed new Deferral and Variance Accounts, as documented in Exhibit 9;
8) An Order as permitted under Section 36.11 of the Electricity Act requiring the IESO to settle past Class A submissions, as further detailed in Exhibit 9;
9) Such other approvals that API may request and that the OEB accepts;
10) API respectfully requests that its current rates be deemed interim should the OEB be unable to issue a Decision on updated 2025 rates with sufficient time for API to implement the rates on January 1, 2025.

Certification of accuracy and completeness of application:

API certifies that the Application has been reviewed and approved by the Vice President Finance and Chief Financial Officer. A signed certification statement is included as Attachment1C.

Confidential Information:

API confirms that none of the information included with this Application is being produced in confidence. The application does not include any confidential information.

1.3.5 EXTENSION OF CODE EXEMPTIONS IN LICENCE

In 2015, API applied to the OEB (EB-2015-0199) for an amendment to its Electricity Distribution Licence (EB-2009-0272) relating to provisions of the Standard Supply Service Code setting a mandatory date for implementation of time of use ("TOU") billing, and provisions of the Distribution System Code related to billing accuracy and limiting estimated bills.

The essence of API's application was that while it had installed smart meters for all services in the required customer classes, for a small subset of its customers in very remote and low-density areas it was not economically possible to transition to TOU billing. API identified that for each area not covered by its AMI infrastructure at the time, the cost to implement TOU billing would range from $2,000-$10,000 per meter in initial capital costs and $500-5000 per meter in annual O&M costs.

API's request was approved, and the license exemptions have since been extended, and amended to also apply to API's requirement to offer customers a choice of electricity pricing options (TOU and ULO). The Current licence exemption for this group of hard-to-reach customers currently expires December 31, 2024.

As of the filing date of this Application, API has not been able to identify cost-effective solutions for transitioning the majority of its customers with hard to reach meters to smart metered billing. While the cost effectiveness of communication options has improved in some areas, the capital and ongoing maintenance cost of AMI collectors that would be required for a large number of very low-density areas remains a barrier. In order to cost-effectively collect hourly reads and transition to TOU billing for these customers, API expects that a combination of solutions would be required, as follows:

1) Cost-effective communications options would need to be available – these alternatives are becoming increasingly available in API's service area; AND,

2) The costs of capital infrastructure, in consideration of the number of meters/accounts would need to be reasonable – since this is unlikely to occur through natural customer growth and API's existing AMI solution does not offer cost-effective solutions for very small/isolated groups numbers of meters. API will, as it works towards replacement of its aging AMI infrastructure from initial deployment, look to cost effectively update infrastructure to collect TOU readings from residential and small commercial customers in low density areas.

API intends to file a separate application, pursuant to Section 74 of the Act, requesting that the code exemptions included in Section 4 of Schedule 3 of its Distribution Licence (ED-2009-0072) be extended to December 31, 2029, coinciding with the end of the rate-setting term covered by the current Application.

In the event that the OEB does not approve this extension in a timely manner, API would need to spend a material amount of capital to ensure compliance with its licence. This would require API to amend the Application to increase its 2025 rate base as well as its 2025 O&M costs related to the ongoing operation and maintenance of AMI infrastructure.

1.3.6 BILL IMPACTS

For the purpose of the notice of application, the 2025 distribution rates proposed by API will result in *decreases* to the distribution portion of the bill (Subtotal A of the Bill Impact Model) for residential customers using 750 kWh per month (RPP-TOU) of -$6.05 (-15.5%) and for small commercial customers using 2000 kWh per month (RPP-TOU) of -$2.23 (-2.0%)

Table 1 below shows a summary of all components of the bill impacts for a range of consumption scenarios across all customer classes.

Further explanation of bill impacts is found in Section 8.3.13 of Exhibit 8.

Table 1 – Bill Impacts

Rate Class/Scenario	Distribution Billing Unit	RPP? Non-RPP Retailer? Non-RPP Other?	Consumption (kWh)	Demand kW (if applicable)	Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of
Residential R1(i)	kwh	RPP	750		1
Residential R1(ii)	kwh	RPP	2,000	-	1
Residential R2	kw	Non-RPP (Other)	225,000	500	1
Seasonal	kwh	RPP	200	-	1
Seasonal-10th percentile	kwh	Non-RPP (Other)	3,000	-	75
Street Lighting	kwh	RPP	15	10	1

	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
Classification	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Residential R1(i)	$ (6.05)	-14.61%	$ (7.65)	-14.94%	$ (9.87)	-14.83%	$ (9.23)	-6.35%
Residential R1(ii)	$ (2.23)	-2.02%	$ (6.51)	-4.80%	$ (12.42)	-7.04%	$ (11.59)	-3.00%
Residential R2	$ (1,439.43)	-54.42%	$ (6,915.23)	-198.66%	$ (7,447.44)	-105.22%	$ (8,309.25)	-24.31%
Seasonal	$ 10.48	10.95%	$ 10.18	10.33%	$ 9.58	9.34%	$ 8.98	7.58%
Seasonal-10th percentile	$ 9.24	10.42%	$ 9.22	10.33%	$ 9.17	10.24%	$ 8.59	10.02%
Street Lighting	$ 218.18	17.11%	$ 155.19	12.18%	$ 147.50	11.12%	$ 139.38	8.99%

	Distribution				Total Bill			
Classification	**Current Bill**	**2025 Propose**	**Change ($)**	**Change (%)**	**Current Bill**	**2025 Propose**	**Change ($)**	**Change (%)**
Residential R1(i)	$ 41.39	$ 35.34	$ (6.05)	-14.6%	$ 145.34	$ 136.11	$ (9.23)	-6.35%
Residential R1(ii)	$ 110.04	$ 107.81	$ (2.23)	-2.0%	$ 386.22	$ 374.63	$ (11.59)	-3.00%
Residential R2	$ 2,644.81	$ 1,205.38	$ (1,439.43)	-54.4%	$ 34,173.69	$ 25,864.44	$ (8,309.25)	-24.31%
Seasonal	$ 95.75	$ 106.23	$ 10.48	10.9%	$ 118.42	$ 127.41	$ 8.98	7.58%
Seasonal-10th percentile	$ 88.65	$ 97.88	$ 9.24	10.4%	$ 85.80	$ 94.39	$ 8.59	10.02%
Street Lighting	$ 1,275.00	$ 1,493.18	$ 218.18	17.1%	$ 1,549.84	$ 1,689.23	$ 139.38	8.99%

1.3.7 STATEMENT AS TO THE FORM OF HEARING REQUESTED

This Application is supported by written evidence, which may be amended from time to time, prior to the Board's final decision on the Application.

API requests that pursuant to Section 34.01 of the Board's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing in an effort to minimize costs but understands that if certain issues remain unsettled, the utility may be required to participate in an oral hearing.

1.3.8 DEVIATIONS FROM FILING REQUIREMENTS OR CHANGES TO MODELS

Except where specifically identified in the Application or noted below, API followed the Filing Requirements and used the OEB-issued Cost of Service models in order to prepare this application. The Excel version of the completed Cost of Service Checklist is being filed in conjunction with this application.

In any case where a specific section of the Filing Requirements is not applicable to API's circumstances, API has indicated "N/A" and provided an accompanying description in the Cost of Service Checklist.

The following changes to OEB models, use of alternative models, or use of alternative inputs to the models were necessary to address API's circumstances:

- API worked with OEB Staff to employ adjustments to employ preliminary models for 2025 filers, with adjustments to accommodate API's specific rate design and customer classifications.
- API has developed its own Tariff and Bill Impact model, as the standard model required significant updates to reflect API's atypical customer classes, rate design, and the impacts of multiple rate subsidy programs. The Tariff and Bill Impact model developed by API mirrors the standard OEB model and contains most of the same inputs.
- Consistent with past API COS applications, API has entered equivalent rates into Tab 16.1 Revenue of the Cost Allocation model for the R1 and R2 (Residential and GS>50kW) classes. Further, API made adjustments to cells F39 and K39 of Tab I6.1 Revenue in the Cost Allocation Model to bring the correct rates into the calculation.

- API has worked with OEB Staff to ensure the allocation and rate design of the SME Charge Variance Account (USOA 1551) is allocated to and disposed from the Residential R1 (i), Residential R1(ii), and Seasonal Classes, and the Residential R2 class is not considered in this account disposition. This ensures that only the smart metered classes are allocated the associated balance.
- API has made adjustments to the RRWF to enable the following:
  - Calculate the adjustments to the Seasonal class's fixed-variable split;
  - Calculate the RRRP-adjusted 2025 Proposed billing rates and 2025 RRRP proposed funding;
  - Update the revenue reconciliation to incorporate the proposed billing rates and RRRP funding.
- Other immaterial formulaic adjustments have been shared directly with OEB staff.

1.3.9 CHANGES IN METHODOLOGIES

Pursuant to the commitment made in API's 2020 COS application, API has undertaken a new methodology for Load Profiles, which is based on API-specific meter data. Prior applications were based on scaled estimated "HONI" load profiles developed some years ago for API. Further details of the load profile are available in Exhibit 7.

There have been no other material changes in methodologies since API's 2020 cost of service application.

1.3.10 BOARD DIRECTIVE FROM PREVIOUS DECISIONS

API is not aware of any Board Directives from any previous Board Decisions and/or Orders which would require consideration in this Application.

1.3.11 CONDITIONS OF SERVICE

API's conditions of service were last fully updated in April of 2019 (with limited administrative adjustments made in 2023), and are accessible on its website at: http://www.algomapower.com/Userfiles/File/2019%20API%20Conditions%20of%20Service%2004182019.pdf

API confirms that there are no rates or charges listed in the Conditions of Service that are not listed in its Tariff of Rates and Charges.

API is in the process of updating its Conditions of Service in response to the OEB's EVCCP.

1.3.12 ACCOUNTING STANDARDS FOR REGULATORY AND FINANCIAL REPORTING

Accounting Standard used in Application

API has reported under the Accounting Standards for Private Enterprises accounting standard since January 1, 2011. Previous to January 1, 2011, API reported in accordance with the Canadian Generally Accepted Accounting Principles accounting standard. API confirms that it made the required changes to its capitalization policies and depreciation rates in 2013. These changes were reflected and approved within API's Cost of Service proceeding, EB-2014-0055, and values presented within this application have also been reported using this methodology.

Compliance with the Uniform System of Accounts

With one exception, API has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application. Due to the non-significant dollar value associated with Retail Service Charges, API has not followed the Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. Further explanation can be found in Exhibit 9.

API has adopted the various account changes prescribed by the Board in relation to the USoA (Article 210 – Chart of Accounts and Account 220 – Account Descriptions).

The useful lives proposed by API in this Application are generally consistent with the typical useful lives in the Kinectrics Report commissioned by the OEB dated July 8, 2010. API has not changed its accounting methodology since its last rebase in 2020.

Changes in Tax Status:

API is a corporation incorporated pursuant to the Ontario Business Corporations Act and has not had a change in tax status since its last Cost of Service application.

Existing/Proposed Accounting Orders

EB-2013-0368 PENSION AND OTHER POST-EMPLOYMENT BENEFITS DEFERRAL AND VARIANCE ACCOUNTS

On December 12, 2013, API received a Decision and Order from the Board (EB-2013-0368) approving the establishment of specific deferral and variance 1508 accounts related to pension and other post-employment benefits ("P&OPEB") subject to the conditions of the Order. The description of these deferral and variance accounts can be found in Section 9.3.2. API has continued to book journal entries in accordance with the Accounting Order to record the difference between P&OPEB expenses under Section 3461 and Section 3462. API is not seeking recovery of any variances recorded in these accounts within this application.

EB-2015-0040 REPORT OF THE OEB RE: REGULATORY TREATMENT OF PENSION AND OTHER POST-EMPLOYMENT BENEFITS

On September 14, 2017, the OEB issued a report regarding the Regulatory Treatment of P&OPEB Costs. Within the report, the OEB provides for the establishment of the P&OPEB Forecast Accrual versus Actual Cash Payment Differential variance account on a generic basis, effective January 1, 2018. API has been using the appropriate 1522 sub accounts and is requesting disposition of the accumulated carrying charges within Exhibit 9 of this application.

EB-2015-0304 WIRELINE POLE ATTACHMENT CHARGES

On July 20, 2018, the OEB issued a letter outlining accounting guidance in connection with the implementation of the new pole attachment charge. API has been accumulating the difference between the rates incorporated into API's 2020 Cost of Service Application and the rates published by the OEB, along with applicable carrying charges, in the 1508 sub accounts that have been prescribed by the OEB. API's proposed revenue requirement for 2025 reflects the revenue expected to be earned for pole rental revenues at the latest OEB published rates, adjusted for the estimated rate increase in 2025. API is also seeking disposition of the accumulated variance in this account.

EB-2015-0304 ENERGY RETAILER SERVICE CHARGES

On February 14, 2019, the OEB issued a Decision and Order which included accounting guidance regarding energy retailer service charges. Effective May 1, 2019, API started accumulating the difference between the revenue collected from the current electricity distributor Retail Service Charges and the revenue collected with the updated electricity Retail Service Charges along with applicable carrying charges in the 1508 sub accounts that have been prescribed by the OEB. API's proposed revenue requirement for both 2020 and 2025 reflect the revenue expected to be earned for Retail Service Charge revenues at the new enhanced rates, so the principal variance was accumulated to the end of 2019 only, with carrying charges continuing to current date. API is seeking disposition of the accumulated variance in this account within this proceeding.

EB-2017-0153 API INTERIM DISTRIBUTION LICENSE IN TOWNSHIP OF DUBREUILVILLE, AND EB-2018-0271 LEAVE TO SELL DUBREUIL LUMBER INC.'S ELECTRICITY DISTRIBUTION SYSTEM TO API

On April 4, 2017, the OEB issued an Order requiring Dubreuil Lumber Inc. to surrender possession and control of the electricity distribution system in the Township of Dubreuilville to Algoma Power Inc. Within that order, API was directed to record revenues collected from customers within the service area of Dubreuil Lumber Inc., and the costs of operation and maintenance of the system in a deferral account under the Uniform System of Accounts. API accumulated these costs along with additional capital and one-time costs in OEB 1508 sub accounts. Certain one-time costs were approved to be recovered within API's 2020 Cost of Service proceeding, while incremental 2017-2019 OM&A DLI-related costs as well as depreciation and cost of capital on 2017-2019 forecasted capital investments are being requested for final true-up and disposition withing this proceeding.

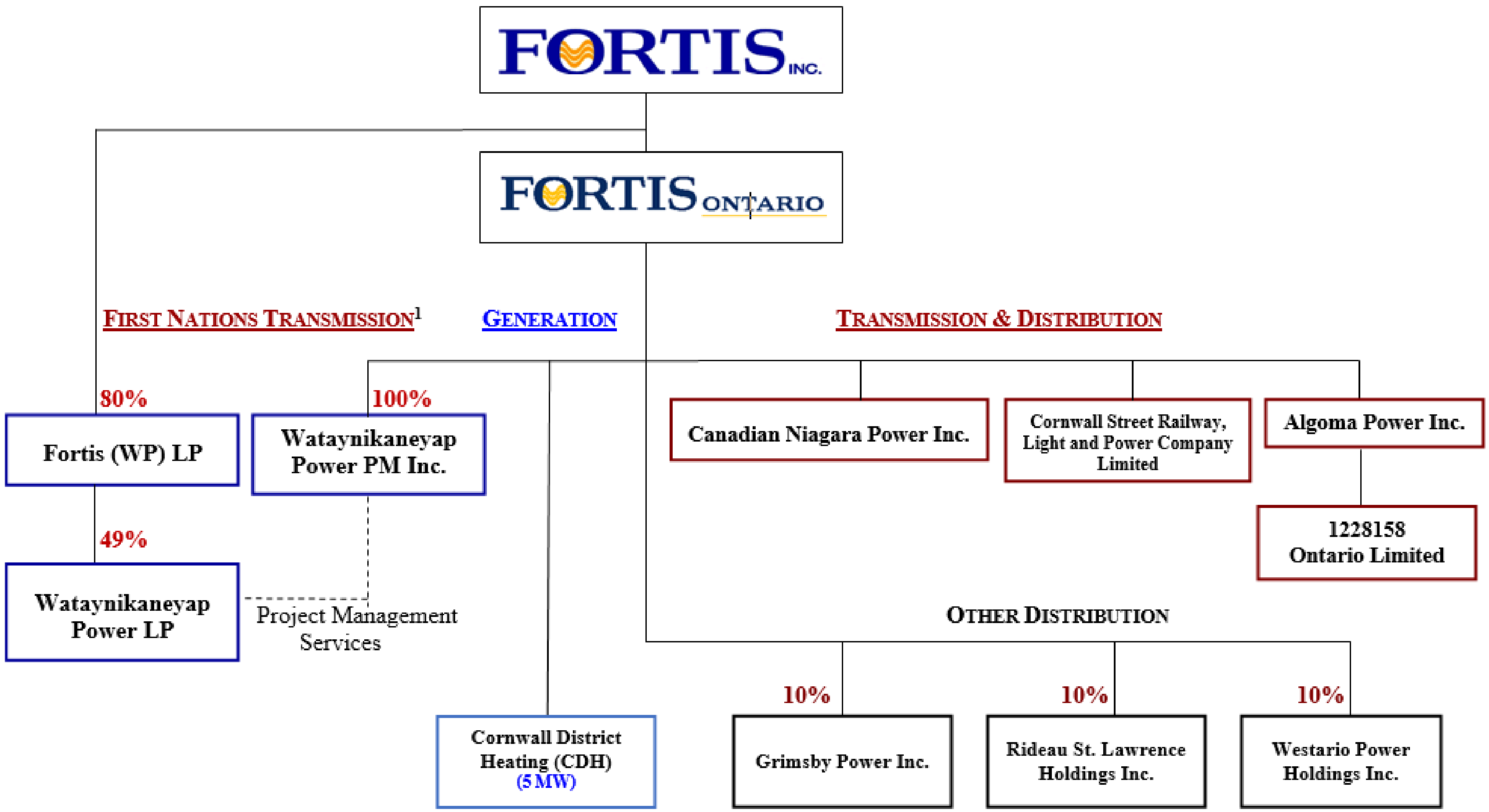
1.3.13 ACCOUNTING TREATMENT OF NON-UTILITY BUSINESS

API confirms it does not conduct any non-utility related business.

1.3.14 CORPORATE ORGANIZATION

The chart on the following page illustrates the corporate entities relationship of API, its shareholder and its affiliates carrying on business in Ontario:

Figure 1 - Corporate Entities Relationship Chart and Utility Organizational Structure



[1] FortisOntario has a 100% interest in Fortis (WP) GP Inc., the General Partner of Fortis (WP) LP.

Organization of Entities

API is a wholly-owned subsidiary of FortisOntario Inc. (“FortisOntario”), which is headquartered in Fort Erie, Ontario. FortisOntario owns and operates generation, transmission and distribution businesses in the province of Ontario. Founded in 1892, FortisOntario began generating electricity in 1905 from its Rankine Generating Station located on the Canadian side of the Niagara River and subsequently began distributing electricity to the Town of Fort Erie in 1907. The Rankine Generating Station ceased operations in 2005 and was transferred to the Niagara Parks Commission in 2009. Accordingly, FortisOntario’s operations in Ontario are primarily transmission and distribution.

FortisOntario is the Ontario-based subsidiary of Fortis Inc. ("Fortis"), which is the largest investor-owned gas and electric distribution utility in Canada. With total assets of approximately $68 billion and annual revenues of approximately $12 billion, Fortis serves approximately 3.5 million gas and electricity consumers across Canada, the United States and the Caribbean. Fortis is a publicly traded company listed on the TSX and the NYSE.

FortisOntario also owns Canadian Niagara Power Inc. (“CNPI”) (ED-2002-0572 and ET-2023-0305), and Cornwall Street Railway Light and Power Company Limited (“Cornwall Electric”) (ED-2004-0405). CNPI is a single corporate entity which has two internal business units: a transmission business and a distribution business. CNPI’s distribution business serves approximately 30,000 customers in the Town of Fort Erie, the City of Port Colborne, and the Town of Gananoque. CNPI’s transmission business owns transmission assets in the Niagara Region. Cornwall Electric serves approximately 26,000 customers in and around the City of Cornwall.

FortisOntario is a licenced generator (EG-2023-0237), which owns a 5 MW natural gas cogeneration district heating plant located in Cornwall, Ontario. The Cornwall district heating facility is an embedded generator selling district heating to local customers and electricity directly to Cornwall Electric, which is isolated from the IESO-controlled grid.

FortisOntario holds a ten percent (10%) interest in Westario Power Inc. (ED-2002-0515), a 23,000 customer electricity distributor located in mid-western Ontario, a ten percent (10%) interest in Rideau St. Lawrence Holdings Inc. (ED-2003-0003), a 6,000 customer electricity distributor located in southeastern Ontario, and a ten percent (10%) interest in Grimsby Power Inc. (ED-2002-0554), an 11,000 customer electricity distributor located in the Niagara region. Accordingly, Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc. are not affiliates of API as defined by the *Ontario Energy Board Act, 1998*.

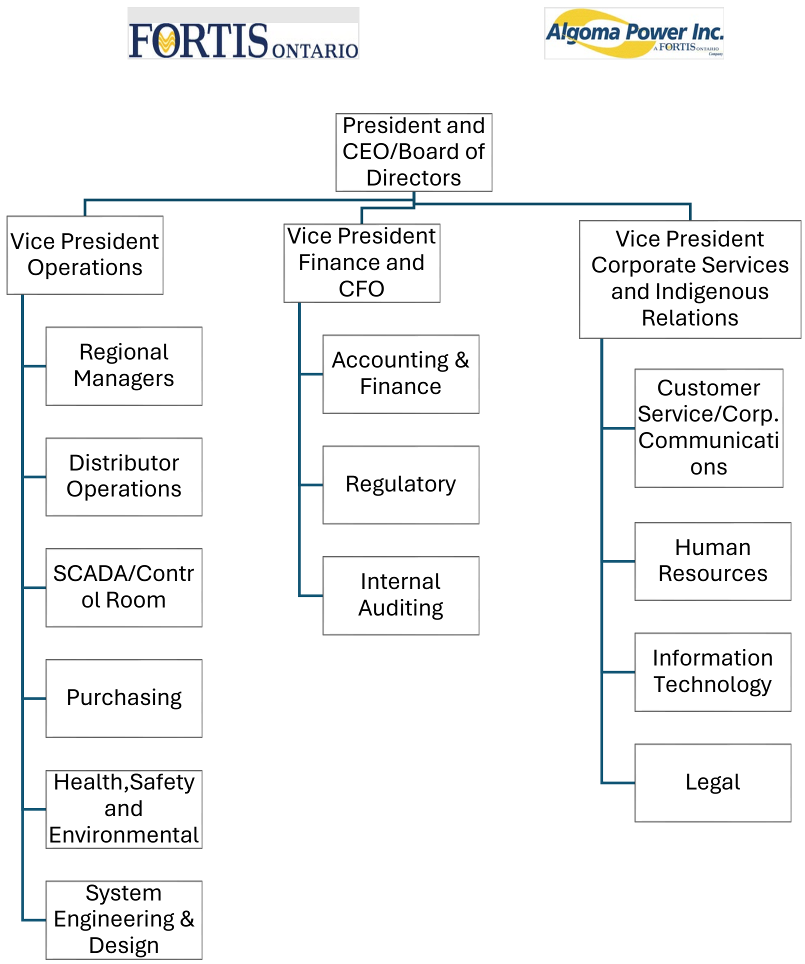
Fortis is also a partner in the First Nations-led Wataynikaneyap Power LP transmission partnership (ET-2015-0264) with 24 First Nations partners.

The numbered company shown in the organizational chart under API is a legacy entity which does not currently conduct any business. API does not allocate any staff or any other resources to this company.

Utility Organizational Structure

The chart on the following page illustrates the utility's organization structure showing main units and senior management positions with the utility. The CEO and Vice Presidents are also appointed as officers of API (i.e. each member of FortisOntario Executive holds the same position with respect to API).

Figure 2 – Organization Structure



Shared Corporate Services

Shared corporate services being provided to API include the following:

- Executive Services
- Finance
- Information Technology
- Human Resources
- Health, Safety and Environment
- Regulatory
- Engineering
- Legal

It is anticipated that shared corporate services will continue to be provided to API from affiliates in the future.

Corporate Governance

The objective of effective and responsive corporate governance is achieved by continually reviewing structures, policies, and programs against best practices in utility governance.

One of those structures is the API board of directors. API has three directors who serve on its board of directors. Two of the API directors are also officers of API, CNPI, FortisOntario and Cornwall Electric and one director is independent, such that one third of the directors are independent as required by the OEB's Affiliate Relationships Code.

Board of Directors' Mandate

FortisOntario ensures a level of consistency in the governance function of its Ontario operating subsidiaries. The role of the API board is to supervise the management of the business and affairs of API. In doing so, the directors are required to act honestly and in good faith with a view to the best interests of the corporation. Both in legal and practical terms, this means that the board must have regard to the interests of varying API stakeholders, including shareholders, customers and creditors, as well as exercising independent judgement in determining the best interests of the corporation. In a number of respects FortisOntario provides key services relating to API's operations, so that the API board has the resources it requires to ensure that its strategy, risk management and internal controls and processes are appropriately implemented and maintained in accordance with the standards FortisOntario requires from all of its subsidiaries.

In conjunction with these responsibilities, the directors of API understand that they have a fiduciary duty to API.

Board Meetings

API’s board is scheduled to meet in Q2 and Q4 of 2024 and 2025.

Qualifications and Continuing Education

API's non-independent directors are also executive officers and/or directors of API, its affiliates and its parent company, FortisOntario. This ongoing active engagement on the boards and executive management of the parent and affiliates of API ensures that these directors maintain the knowledge, skill, continuing education and experience necessary to meet their obligations as directors of API. The non-independent directors and officers of API are also involved in the selection of the independent board member of API to that they are independent, and that they have the level of skill and knowledge necessary to meet their obligations as a director of API. In addition, continuing education sessions are included in API board meetings to broaden the skill and knowledge of all directors. API's current independent director is a lawyer with expertise in corporate governance.

Code of Conduct and Ethics Policy

The board of directors of API has approved a written Code of Conduct for the directors, officers and employees, (the "Code" or "Code of Conduct"). This Code of Conduct is consistent between FortisOntario and all of its operating subsidiaries. The monitoring of ethical business conduct of API's employees, officers and directors is a governance function exercised primarily by API's parent, FortisOntario.

The API board monitors compliance with its Code by updates from executive management of API (who act in a dual capacity as executive management of FortisOntario) on Code of Conduct violations. The board of API has also approved a Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing and an Anti-Corruption Policy to satisfy itself regarding compliance with the Code. In other words, allegations of Code of Conduct violations would be brought to the attention of the parent company, FortisOntario, and managed in accordance with its policies. Any reporting of a Code of Conduct violation involving API would be brought to the attention of the API board by management of API and/or the management or board of FortisOntario.

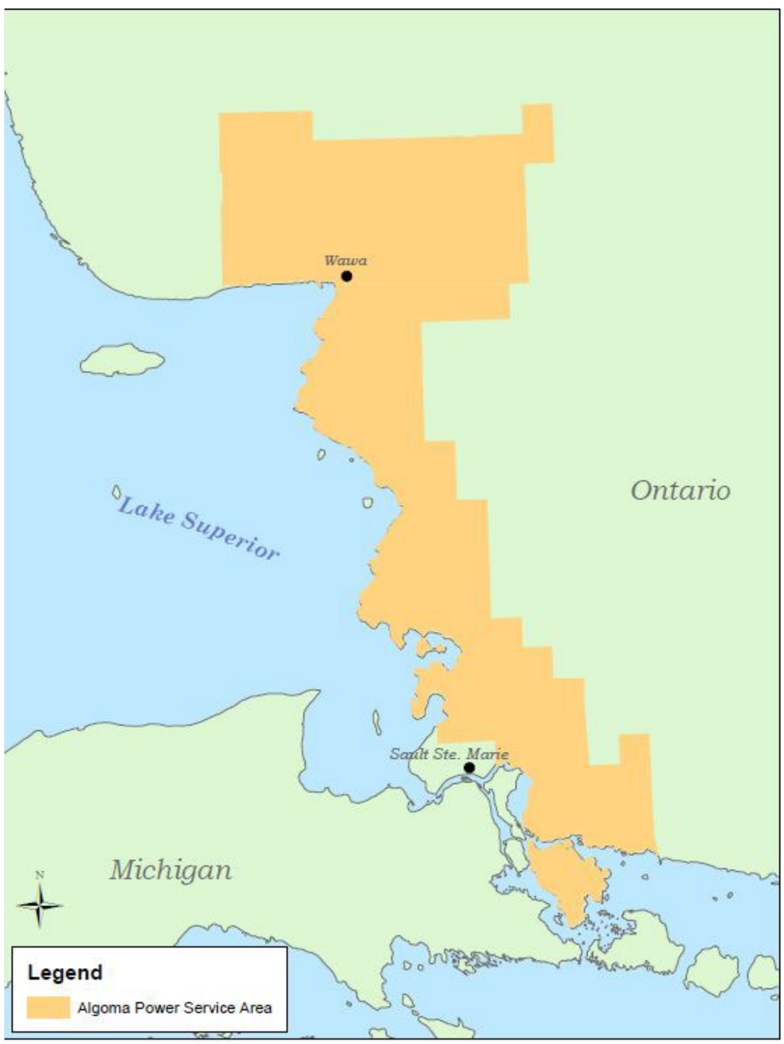
1.4 DISTRIBUTION SYSTEM OVERVIEW

1.4.1 SERVICE AREA OVERVIEW

API's service area extends approximately 93 km east and 255 km north of the City of Sault Ste. Marie, covering approximately 14,200 km2, which includes multiple First Nation Reserves, 14 organized townships, and a large number of unorganized townships.

The map below shows the extent of API's service area. Additional maps showing the communities served by API and township boundaries are included at Attachment 1D. A more detailed overview of API and its service area, unique aspects and key challenges can be found in Section 3 of the Business Plan, which is included as Attachment 1B.

Figure 3 – API's Service Area



1.4.2 HOST/EMBEDDED DISTRIBUTOR AND NEIGHBOURING UTILITIES

API is connected directly to the transmission system of Hydro One Sault Ste. Marie Inc. (ET-2007-0649) via eight different delivery points. As such, API is not an embedded distributor.

The following electricity distributors are adjacent to API's service area:

- PUC Distribution Inc. (ED-2002-0546)
- Hydro One Networks Inc. (ED-2003-0043)

1.4.3 TRANSMISSION OR HIGH VOLTAGE ASSETS

API does not have any transmission or high voltage assets (> 50 kV) deemed by the OEB as distribution assets. API does not have any such assets that it is asking the OEB to deem as distribution assets in the present application.

1.5 APPLICATION SUMMARY

This section is sumarizes the elements of API's 2025 cost-of-service, explaining how each element is determined and explaining the relationship between the various components. The major components covered in this application summary are as follows:

- Revenue Requirement
- Budgeting Assumptions
- Load Forecast Summary
- Rate Base and DSP
- Operation Maintenance and Administration Expense
- Cost of Capital
- Cost Allocation and Rate Design
- Deferral and Variance Account Disposition
- Bill Impacts

Revenue Requirement

The proposed Service Revenue Requirement for the 2025 test year of $35,768,551 reflects an increase of $2,654,124 or 36.1% relative to 2020 Board Approved. The Base Revenue Requirement on which rates are calculated is $35,112,551, reflecting other revenue offsets of $656,000.

Applying API's 2024 approved rates to its 2025 forecast of load, demand and customer counts produces a forecasted revenue of $31,918,843, resulting in a revenue deficiency of $3,193,707. API is applying for 2025 rates and RRRP funding to eliminate this deficiency and recover its revenue requirement.

Table 2 – 2020-2025 Revenue Requirement

Item	2020 Board Approved	2020	2021	2022	2023	2024 Bridge	2025 Test
OM & A Expenses	$ 13,687,754	$ 13,356,735	$ 13,608,330	$ 13,901,859	$ 13,993,487	$ 14,606,472	$ 16,319,014
Depreciation Expense	$ 4,034,602	$ 3,924,249	$ 4,049,472	$ 4,188,459	$ 4,297,723	$ 4,828,861	$ 5,675,782
Property Taxes	$ 118,600	$ 120,695	$ 146,380	$ 141,693	$ 243,806	$ 350,000	$ 260,000
Total Distribution Expenses	$ 17,840,956	$ 17,401,679	$ 17,804,182	$ 18,232,011	$ 18,535,016	$ 19,785,333	$ 22,254,796
Regulated return on Capital	$ 8,184,098	$ 7,918,581	$ 8,133,195	$ 8,467,199	$ 9,124,336	$ 10,801,134	$ 12,555,753
Grossed up Income Tax	$ 259,084	$ 635,374	$ 734,407	$ 258,575	-$ 227,130	$ 203,603	$ 958,002
Service Revenue Requirement	**$ 26,284,138**	**$ 25,955,634**	**$ 26,671,784**	**$ 26,957,785**	**$ 27,432,222**	**$ 30,790,070**	**$ 35,768,551**
Less:Revenue Offsets	-$ 488,791	-$ 444,041	-$ 619,526	-$ 706,011	-$ 1,579,997	-$ 1,911,647	-$ 656,000
Base Revenue Requirement	**$ 25,795,347**	**$ 25,511,593**	**$ 26,052,258**	**$ 26,251,774**	**$ 25,852,225**	**$ 28,878,423**	**$ 35,112,551**

The primary drivers of the change in revenue requirement are increases in the required return on rate base and amortization expense and an increase in OM&A expenses. Increases in Grossed Up PILS and Property Taxes also contribute to a lesser extent. Each of these contributing factors is summarized in Section 6.3.2 of Exhibit 6. Table 3 below compares each component of API's proposed 2025 revenue requirement to 2020 Board Approved amounts.

Table 3 – Change in Revenue Requirement since Last Board-Approved

Driver	2020 Board Appr	2025 Test Year	Difference	% Differenc
Long Term Debt Rate	5.81%	5.59%	-0.22%	-3.8%
Short Term Debt Rate	1.76%	6.23%	4.47%	254.0%
Weighted Average Debt Rate	5.54%	5.63%	0.09%	1.6%
Rate of Return on Equity	8.78%	9.21%	0.43%	4.9%
Regulated Rate of Return on Rate Base	**6.84%**	**7.06%**	**0.23%**	**3.3%**
Controllable Expenses	$ 13,806,882	$ 16,579,014	$ 2,772,132	20.1%
Power Supply Expense	$ 23,416,069	$ 32,534,015	$ 9,117,946	38.9%
Working Capital Base	**$ 37,222,951**	**$ 49,113,029**	**$ 11,890,078**	**31.9%**
Working Capital Allowance Rate	7.50%	7.50%	0.00%	0.0%
Working Capital Allowance ("WCA")	**$ 2,791,721**	**$ 3,683,477**	**$ 891,756**	**31.9%**
Net Fixed Assets Opening Test Year	$ 114,801,408	$ 172,167,954	$ 57,366,546	50.0%
Net Fixed Assets Closing Test Year	$ 119,056,280	$ 176,058,022	$ 57,001,742	47.9%
Average Net Fixed Assets	$ 116,928,844	$ 174,112,988	$ 57,184,144	48.9%
Working Capital Allowance	$ 2,791,721	$ 3,683,477	$ 891,756	31.9%
Rate Base	**$ 119,720,565**	**$ 177,796,465**	**$ 58,075,900**	**48.5%**
Deemed Interest Expense	$ 3,979,512	$ 6,005,731	$ 2,026,220	50.9%
Target Return on Deemed Equity	$ 4,204,586	$ 6,550,022	$ 2,345,436	55.8%
Regulated Return on Rate Base	**$ 8,184,098**	**$ 12,555,753**	**$ 4,371,655**	**53.4%**
Regulated Return on Rate Base	$ 8,184,098	$ 12,555,753	$ 4,371,655	53.4%
OM&A	$ 13,687,754	$ 16,319,014	$ 2,631,260	19.2%
Property Taxes	$ 118,600	$ 260,000	$ 141,400	119.2%
Depreciation Expense	$ 4,034,602	$ 5,675,782	$ 1,641,180	40.7%
Income Taxes	$ 259,084	$ 958,002	$ 698,918	269.8%
Service Revenue Requirement	**$ 26,284,138**	**$ 35,768,551**	**$ 9,484,413**	**36.1%**
Revenue Offset	-$ 488,791	-$ 656,000	-$ 167,209	34.2%
Base Revenue Requirement	**$ 25,795,347**	**$ 35,112,551**	**$ 9,317,204**	**36.1%**

Budgeting and Accounting Assumptions

In preparing its cost forecasts for the Application, API has assumed an inflation rate of 2.75%. API has not factored any significant growth into its forecasts since load forecasts and customer counts remain relatively flat and in line with historical weather-normalized values.

API adopted MIFRS and confirms that it made the required changes to its capitalization policies and depreciation rates in 2013. These changes were reflected and approved within API's 2015 Cost of Service proceeding, EB-2014-0055, and values presented within this application have also been reported using this methodology. There are therefore no impacts resulting from a change in accounting standard.

Load Forecast Summary

The load forecast for 2025 is based on a methodology that predicts class specific consumption using a regression analysis that relates historical monthly wholesale kWh usage to monthly historical heating degree days and cooling degree days, as well as other explanatory variables.

In API's case, variation in monthly electricity consumption is influenced by weather (e.g. heating and cooling), which is by far the most dominant effect on most systems, the number of days per month and the number of customers. The following table compares the 2020 Board Approved billing units forecast to the proposed billing units forecast.

Table 4 – Change in Billing Units since Last Board-Approve

	2020 Board Approved	2025 Test Year Proposed	Change	% Change
Customers (incl. Devices)	13,238	13,592	354	3%
kWh	227,437,703	317,549,813	90,112,110	40%
kW (excl. Street Lights)	248,605	372,457	123,852	50%

Total kW excludes the kW for Street Lighting because the street lighting class is billed for distribution rates based on kWh.

Weather normalized values are determined by using the regression equation with a "10-year average monthly degree days (2014-2023)". The 10-year average is consistent with recent years' weather and has been used in other electricity distribution rate applications accepted by the Board.

Allocation to specific weather sensitive rate classes (R1(i), R1(ii), R2, and Seasonal) is based on weather sensitivity factors of these classes. Further adjustments are made to the R2 rate class to account for known significant load increases enabled by a recent large capital project (#4 Circuit project).

The 2025 load forecast is summarized in the following table. Detailed explanations of the load forecast can be found in Exhibit 3.

Table 4 - Load Forecast

	2020 Board Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Weather Normal	2025 Test Weather Normal
Purchases										
Actual kWh Purchases		217,280,995	241,087,151	255,923,211	252,540,603	265,226,888	279,572,890	281,399,999		
Predicted kWh	246,292,289	222,969,696	231,004,602	238,654,515	248,745,294	265,662,737	281,017,552	282,763,701	287,962,762	288,843,744
% Difference between actual and predicted purchases		2.6%	(4.2%)	(6.7%)	(1.5%)	0.2%	0.5%	0.5%		
Loss Factor	1.0829								1.0873	1.0873
Total Billed	227,437,703	203,063,777	224,565,775	235,800,481	229,140,220	244,314,344	256,287,580	259,742,424	264,839,930	265,650,171
Billing Determinants										
Residential										
Customers	8,116	7,596	7,640	7,698	7,925	8,205	8,361	8,485	8,553	8,621
kWh	84,857,056	76,321,856	82,424,404	86,629,136	91,478,383	92,005,690	99,292,265	96,395,846	100,119,668	102,025,758
General Service < 50 kW										
Customers	997	961	961	951	969	999	1,025	1,055	1,054	1,053
kWh	28,480,011	25,604,789	26,132,430	26,695,949	27,143,067	27,745,373	29,567,137	28,496,501	29,334,547	29,627,607
R2 GS>50 kW										
Customers	37	38	40	40	41	43	46	47	46	45
kWh	107,645,160	94,512,143	109,385,574	115,631,849	103,396,925	117,544,957	120,294,405	128,188,723	128,802,125	179,389,418
kW	248,605	210,836	234,798	243,010	232,897	251,732	260,826	278,055	288,517	372,457
Street Lights										
Devices	1,128	1,070	1,067	1,075	1,105	1,141	1,146	1,132	1,144	1,156
kWh	581,104	582,537	577,097	566,130	592,582	594,156	592,975	537,366	543,140	548,977
kW	1,615	1,619	1,581	1,574	1,636	1,593	1,706	1,505	1,517	1,517
Seasonal										
Customers	2,960	3,108	3,076	3,039	2,990	2,925	2,849	2,793	2,755	2,717
kWh	5,874,372	6,042,453	6,046,269	6,277,417	6,529,263	6,424,168	6,540,797	6,123,988	6,040,450	5,958,052
Total										
Customer/Connectior	13,238	12,774	12,784	12,801	13,028	13,312	13,426	13,512	13,551	13,592
kWh	227,437,703	203,063,777	224,565,775	235,800,481	229,140,220	244,314,344	256,287,580	259,742,424	264,839,930	317,549,813
kW	250,220	212,455	236,379	244,584	234,533	253,325	262,532	279,560	290,034	373,974

Rate Base and DSP

The proposed Rate Base for the 2025 Test Year of $177,796,465 reflects an increase of $58,075,900, or 48.51% relative to 2020 Board Approved. API's 2020-2025 rate base trend is presented in the following table:

Table 5 – 2020-2025 Rate Base Trend

Year Version	2020 Board Approved	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Gross FA - Openin	$ 191,735,585	$ 187,593,435	$ 192,075,481	$ 200,035,089	$ 207,813,776	$ 226,301,889	$ 267,633,461
Gross FA - Closing	$ 200,479,361	$ 192,075,481	$ 200,035,089	$ 207,813,776	$ 226,301,889	$ 267,633,461	$ 277,843,950
Gross FA - Avg	**$ 196,107,473**	**$ 189,834,458**	**$ 196,055,285**	**$ 203,924,433**	**$ 217,057,832**	**$ 246,967,675**	**$ 272,738,705**
Acc. Depr. - Openi	-$ 76,934,177	-$ 76,332,743	-$ 78,213,558	-$ 82,051,026	-$ 84,586,116	-$ 88,954,683	-$ 95,465,507
Acc. Depr. - Closin	-$ 81,423,081	-$ 78,213,558	-$ 82,051,026	-$ 84,586,116	-$ 88,954,683	-$ 95,465,507	-$ 101,785,928
Acc. Depr.- Avg	**-$ 79,178,629**	**-$ 77,273,150**	**-$ 80,132,292**	**-$ 83,318,571**	**-$ 86,770,399**	**-$ 92,210,095**	**-$ 98,625,717**
Net FA - Avg	**$ 116,928,844**	**$ 112,561,308**	**$ 115,922,994**	**$ 120,605,862**	**$ 130,287,433**	**$ 154,757,580**	**$ 174,112,988**
WCA	**$ 2,791,721**	**$ 3,275,162**	**$ 3,052,949**	**$ 3,256,024**	**$ 3,187,341**	**$ 3,246,139**	**$ 3,683,477**
Total Rate Base	**$ 119,720,565**	**$ 115,836,470**	**$ 118,975,943**	**$ 123,861,886**	**$ 133,474,774**	**$ 158,003,719**	**$ 177,796,465**

The increase from 2020 Board Approved to 2025 Test Year is driven by capital spending over the recent history, which involves several material one-time projects which are further described in section 2.1.1, as well as typical ongoing capital projects. Table 6 below reproduces OEB Appendix 2-AB, which compares planned vs. actual spending over the historical period:

Table 7 – Historical Planned vs. Actual Capital and O&M

CATEGORY	2020			2021		
	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%
System Access	903	1,519	68.1%	963	2,488	158.2%
System Renewal	6,023	4,052	-32.7%	4,700	5,139	9.3%
System Service	562	259	-54.0%	7,978	980	-87.7%
General Plant	1,357	1,425	5.0%	1,238	819	-33.9%
TOTAL EXPENDITURE	8,846	7,254	-18.0%	14,879	9,425	-36.7%
Capital Contributions	- 102	- 168	65.4%	- 100	- 472	372.3%
NET CAPITAL EXPENDITURES	8,744	7,086	-19.0%	14,779	8,953	-39.4%
System O&M	$ 7,015	$ 7,078	0.9%	$ 7,186	$ 7,171	-0.2%

Table 6 (Cont'd)

CATEGORY	2022			2023			2024		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual2	Var
	$ '000		%	$ '000		%	$ '000		%
System Access	930	2,082	123.8%	906	12,989	1333.1%	906	3,295	263.5%
System Renewal	4,822	7,567	56.9%	6,494	4,102	-36.8%	4,616	12,397	168.6%
System Service	472	32	-93.3%	461	11,393	2371.9%	461	1,684	265.3%
General Plant	13,980	16,386	17.2%	1,178	2,241	90.2%	1,098	1,901	73.2%
TOTAL EXPENDITURE	20,205	26,067	29.0%	9,039	30,725	239.9%	7,081	19,278	172.3%
Capital Contributions	- 100	- 264	163.7%	- 100	- 272	171.8%	- 100	- 5,252	5152.1%
NET CAPITAL EXPENDITURES	20,105	25,804	28.3%	8,939	30,453	240.7%	6,981	14,026	100.9%
System O&M	$ 7,294	$ 7,388	1.3%	$ 7,404	$ 7,605	2.7%	$ 7,515	$ 7,883	4.9%

In developing its 2025-2029 DSP, API identified six strategic customer focused objectives that drive capital and O&M plans and related investments over the forecast period:

- Safety, Environmental Protection and Cybersecurity
- Sustaining End of Life Asset Replacement
- Sustaining Vegetation Management
- Reliability and Resilience improvements
- General Plant Investments to Support Productivity and Efficiency
- A Cost-Effective, long term approach to energy transition

API's 2025 Business Plan, included as Attachment 1B describes how the strategic objectives listed above are consistent with its core values and principles, the objectives of the OEB's Renewed Regulatory Framework, as well as the identified preferences of API's customers.

Attachment 1J, which is reproduced in the table below, summarizes how API's material DSP programs address the objectives above, as well as demonstrating cost effectiveness and responsiveness to customer preferences

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Table 8 – Summary of Strategic Priorities and Material Projects

	Worker and Public Safety, Environmental Protection, Cybersecurity	Sustaining End of Life Asset Replacement	Sustaining Vegetation Management	Reliability and Resilience improvements	General Plant Investments to Support Productivity and Efficiency	A cost-effective, long term approach to energy transition	Customer/Stakeholder Preferences	Cost Effectiveness
Service Connections	•work is completed within O.Reg 22/04 requirements •coordination with nearby asset replacment reduces mobilization and emissions	•service connections reviewed for possibility of required nearby asset replacement to minimize mobilization costs.	Sustaining VM allows API to complete Service Connection work efficiently.	N/A	General Plant investments allow API to complete Service connection work efficiently.	Where grid constraint is identfied, NWS will be considered to facilitate connection.	Service connections are completed in response to customer requests	Work is completed in coordination with other requirements, where possible, to minimize mobilization costs.
Small Lines/Stations Capital	•Proactive replacement approach is safer than reactive replacement. •Approach minimizes oil leak risks. •work is completed within O.Reg 22/04 requirements	•Projects identified based on inspection results-failure/performance risk of each asset.	Sustaining VM allows API to complete Small Lines/Stations replacement work efficiently.	•Replacing deteriorated assets prior to failure allows API to reduce or eliminate the outage impact of an unplanned outage.	General Plant investments allow API to complete Small Lines/Stations replacement work efficiently.	N/A	•Proactive approach minimizes outage duration, frequency •Proactive approach minimizes replacement costs	Proactive replacement can be associated with lower costs, ex: due to planned work during regular hours.
Smart Meter Replacement	•Program will be conducted in line with all applicable health and safety requirements •Newer smart metering assets will improve risk mitigation against Cyber Security threats.	Program supports the replacement of Smart Meters and associated infrastructure reaching end of life.	N/A	API's smart metering network supports its outage identification and management.	General Plan investments support API's imlementation of the SM replacement program.	N/A	•Proactive replacement enables billing accuracy. •Program aims to avoid cost permiums for reactive replacements and stabilize costs over time.	•Proactive replacement approach promotes cost-effective replacements. •API's long-term goal is to create a chronologically diverse reverification batch size that stabilizes annual costs •Proactive approach allows API to optimize use of internal resources.
Wawa #2 DS	Rebuild will mitigate existing oil containment risks and improve worker safety.	Wawa #2 DS is one of API's oldest stations, assessed as fair-poor condition. Transformer is in poor condition.	N/A	•Aged transformer presents reliability risk; failure would leave Wawa without backup. •Current station design requires total de-energization of the station for switching or	General Plant investments such as SCADA will enable future efficiencies in the use and operation of the DS.	The incremental costs for a 50% transformer capacity increase are nearly immaterial today, but could avoid costly replacements and upgrades in	•API's proposal is consistent with customer feedback on this project •Project supports cost-effecitveness and reliability improvements.	•"Right Sizing" today will help avoid costly upgrades in the future to address load growth. •New station design will allow API to operate the DS in a more cost-efficient manner.
Goulais TS Refurbishment & Voltage Conversion	•Goulais TS refurbishment will improve overall worker safety and safe working clearances. •Voltage conversion will eliminate API's requirement for a 12.5/25kV autotransformer.	TS Refurbishment is a result of HOSSM's end-of-life asset replacement program.	API's VM Program will support the efficient completion of Voltage Conversion work	Investment will support improved voltage reliability and stability	General Plant investments support API's ability to complete the Voltage Conversion project work.	•HOSSM will upgrade the supply at Goulais TS to 25kV (above like-for-like), which will accommodate long term growth forecasts. •Investments will enable more DER connections and EV charging infrastructure.	•API's proposal is consistent with customer feedback on this project •Investment supports reliability, power quality, connection of new customers, and cost-effectiveness	•API has chosen a balanced approach, the "medium" scenario of voltage conversion. •The voltage conversion plan will result in avoided costs for dual-voltage HOSSM transformer, and API owned station. •Investments in Goulais TS will limit future investments due to long term growth.

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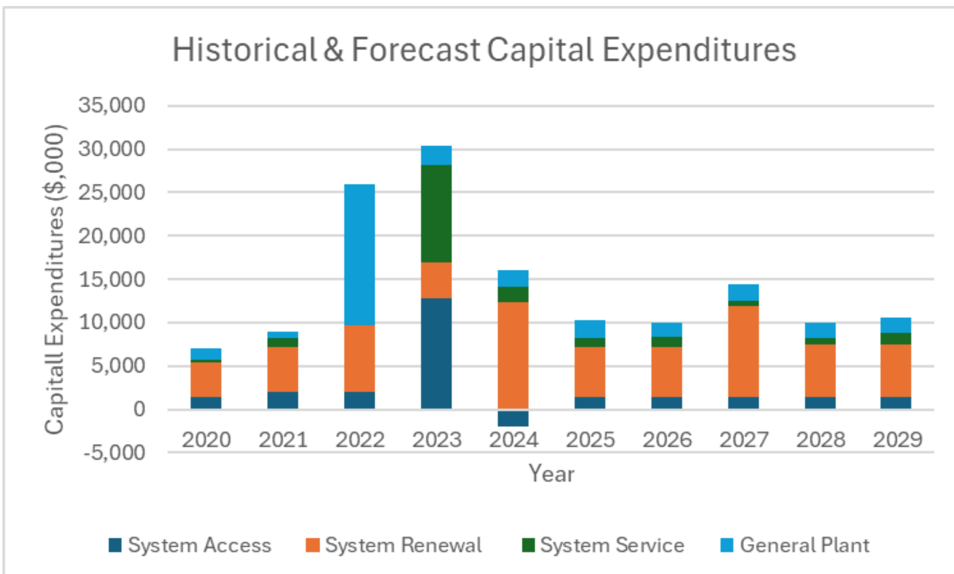
	Worker and Public Safety, Environmental Protection, Cybersecurity	Sustaining End of Life Asset Replacement	Sustaining Vegetation Management	Reliability and Resilience improvements	General Plant Investments to Support Productivity and Efficiency	A cost-effective, long term approach to energy transition	Customer/Stakeholder Preferences	Cost Effectiveness
Distribution and Subtramsmission Line Rebuilds	•Program designed to avoid unplanned outages, which can pose significant worker and public safety risk. •Proactive replacement of poles, wires and hardware ensures that API's is progressively being brought up to more current and safe standards. •Each project is thoroughly reviewed to identify any issues related to the natural environment or areas of cultural significance. •Subtransmission failed poles are asspcoated with wildfire risk.	•Avg. Replacment of 500 poles per year designed to ensure long term stability of pole replacement program.	Sustaining VM Allows API to complete line rebuilds efficiently.	• Reliability and resilience are supported through replacement of older, deteriorated assets with new assets, which inherently are less likely to fail. •Proactive asset replacement minimizes outage impact and duration as unplanned outages can take significantly longer to restore. •Reliability and resilience are further supported through the updating of assets to today's higher standards.	General Plant investments permit API to complete its Line Rebuilds programs efficiently	N/A	•Proactive approach minimizes outage duration, frequency •Proactive approach minimizes replacement costs •Lifespan optimization reduces risk of early writeoffs •Updating assets to today's standard supports resiliency and reliability •Customers supported API's proposed replacement pace in Customer Survey (vs. 10% increase or decrease).	•Lifespan optimization reduces risk of early writeoffs. •Lifespan optimization supports long-term program cost stability and avoids higher future costs. •Planned approach allows API to optimize use of internal resources. •Planned, proactive approach allows API to minimize costly "one-off" replacements. •Planned proactive approach has been historically successful at avoiding unplanned pole failures, which can be significantly more costly to address.
Protection, Automation, Reliability	•Work will be conducted in line with all applicable safety, cybersecurity and environmental policies and requirements. •Investments that reduce future unplanned outages inherently support improved safety. •Reliability improvements resulting in a reduction of outage frequency would reduce the emissions associated with vehicles responding to after-hours outage events.	Where applicable, API will combined Protection, Automation and Reliability work with replacement work due to asset age/condition.	Sustaining VM allows API to complete its Protection, Automation and Reliability programs efficiently.	Projects have been selected to address the highest opportunities for reliability improvements.	General Plant investments permit API to complete its Protetciton, Automation, Reliability programs efficiently	•Many projects have a positive impact on power quality and accommodation of REG/DER projects. •Projects involving distribution automation enable API to connect more DERs employ DERs as Non Wires Solutions for future distribution needs.	API consulted with customers specifically on the Distribution Automation component of this Program. API's proposal is in line with customer preference, which supported "full implementation"	•Many projects will have a positive impact on system losses and enable future cost savings. •Incorporation of advanced SCADA-capable equipment will support operational and asset management efficiences.
Vegetation Management	•Vegetation management work is conducted within applicable safety and environmental requirements • proactive VM work enhances worker and public safety. •API's processes are conducted in line with wildfire mitigation requirements	VM Allows API to complete its asset replacement programs efficiently.	API's Vegetation Management program enables API to keep vegetation near powerlines under adequate control, mitigating the impact of unplanned outages and allowing API efficient access to maintain and operate its distribution assets.	•VM program has contributed to steady improvements in the number and duration of outages. •Tree caused outages will continue to be the #1 outage source in API's territory •VM activities help avoid outages during some extreme weather events, and enable crews to restore power when outages do occur. •VM practices are designed to mitigate Wildfire risks.	General Plant investments support API's VMP.	N/A	•API's proposed approach to Hazard Tree Removal is consistent with direct customer feedback. •API conducts significant VM customer engagement. When landowners decline permission to apply herbicide, API complies. •Program supports cost efficiency and outage reductions as outlines in surrounding sections.	•API's VMP is designed with optimal cycle durations that ensure control is maximized, avoiding long term cost increases. •Despite increasing challenges as a result of reduced ability to apply herbicide as well as inflationary increases, API has incorporated cost efficiency targets into its 2025 budget.

API's capital planning process strives for relatively consistent year to year spending in its sustaining end of life asset replacement programs as well as other programs of a recurring nature. This approach allows API to optimize the use of internal resources and ensures asset replacement on a pace that is consistent with the expected useful life of each type of asset. Larger one-time projects such as substation rebuilds are also paced to keep spending consistent, to the extent possible. Over the period covered by the 2025-2029 DSP, an investment in 2027 is required in the Wawa Main Substation, resulting in a single-year variance from average levels of capital spending in the remaining forecast period years, as shown in the following chart:

Figure 4 – Forecast and Historical Capital Expenditures



In-service capital for 2025 of $10,210,489 represent a $1,466,861 or 16.8% increase over 2020 OEB-Approved.

Variances in overall spending during the historical period were driven by several one-time projects. Three out of four of these projects were previously identified in API's 2020-2024 DSP, while the fourth (#4 Circuit) was customer-driven.

- The SSM Facility (General Plant, 2022)
- The #4 Circuit Project (System Access, 2023)
- The Echo River TS (System Service, 2023)
- Bruce Mines DS Project (System Renewal, 2024)

Details on historical capital variances and details on forecasted capital spending are included in Exhibit 2 and the DSP.

API is not requesting any costs for renewable energy connections/expansions, smart grid projects, non-wires solutions, ACMs, or regional planning initiatives.

Operations, Maintenance and Administration Expense

The proposed OM&A expenses (including property tax) for the 2025 test year of $16,579,014 reflects an increase of $2,772,660 or 20.1% relative to 2020 Board Approved. The following table summarizes API's OM&A trend from 2020 Board Approved to the 2025 Test Year.

Table 9 – 2020-2026 OM&A Trend

	2020 Board Approved	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Operations	$ 1,732,837	$ 1,481,440	$ 1,624,753	$ 1,891,114	$ 2,001,412	$ 2,049,080	$ 2,563,055
Maintenance	$ 5,282,210	$ 5,596,378	$ 5,546,052	$ 5,496,523	$ 5,603,445	$ 5,834,295	$ 6,711,543
Billing and Collecting	$ 986,414	$ 951,794	$ 907,175	$ 891,233	$ 959,849	$ 1,039,479	$ 1,085,080
Community Relations	$ 96,558	$ 34,402	$ 52,871	$ 70,420	$ 68,681	$ 69,488	$ 75,220
Administrative and General	$ 5,589,735	$ 5,292,721	$ 5,477,480	$ 5,552,569	$ 5,360,101	$ 5,614,130	$ 5,884,116
Total	**$ 13,687,754**	**$ 13,356,735**	**$ 13,608,330**	**$ 13,901,859**	**$ 13,993,487**	**$ 14,606,472**	**$ 16,319,014**
%Change (year over year)		-2.4%	1.9%	2.2%	0.7%	4.4%	11.7%

Historical year-over-year variances from 2020 board approved 2023 actuals have ranged from -2.4-2.2%, mainly due to inflationary increases with annual variability in outage response costs, right of way maintenance costs, shared service costs, and staffing costs. Cost drivers for the 2024 Bridge Year and the 2025 Test Year include:

- Increases in vegetation management costs, as further described in Exhibit 4.
- Anticipated increases in API's Land Use costs. Due to the uncertainty associated with these costs, API has proposed a Variance Account in Exhibit 9.
- Increases due to staffing and shared services allocations.

Table 9 on the following page presents API's 2020-2025 OM&A cost drivers, consistent with OEB Appendix 2-JB. Further cost driver analysis is provided in Section 4.2.2 of Exhibit 4.

2025 total compensation of $10,715,672 reflects an increase of $1,277,861 or 13.5% relative to 2020 Board Approved. This increase reflects a compound average growth rate of 2.57% from 2020 Board Approved, or 3.14% from 2020 Actual. Total compensation is summarized in Table 8 below, and analyzed in detail in Section 4.4 of Exhibit 4. API has experienced extreme volatility related to certain benefit costs. As a result, API has requested a deferral account for its Defined Benefit Pension Plan, the details of which can be found in Exhibit 9.

1 **Table 10 – 2020-2025 Compensation**

	2020 Board Approved	2020	2021	2022	2023	2024 Bridge Year	2025 Test Year
Total Salary and Wages	$ 7,311,927	$ 7,024,513	$ 7,272,090	$ 7,524,777	$ 7,784,033	$ 8,386,033	$ 8,682,050
Total Benefits (Current + Accrued)	$ 2,125,884	$ 2,157,643	$ 2,553,574	$ 2,176,843	$ 1,985,267	$ 1,947,508	$ 2,033,622
Total Compensation (Salary, Wages, & Benefits)	$ 9,437,811	$ 9,182,156	$ 9,825,664	$ 9,701,620	$ 9,769,300	$ 10,333,541	$ 10,715,672

Table 11 – 2020-2025 OM&A Cost Drivers

OM&A	Last Rebasing Year (2020 Actuals)	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year	Cumulative Impact (2020 BA to 2025 TY)
Reporting Basis							
Opening Balance[2]	13,688,282	13,356,735	13,608,330	13,901,859	13,993,487	14,606,472	
App 2-K Impact on OM&A	- 182,000	17,000	32,000	- 32,000	483,000	180,000	498,000
Right of Way Land Fees	- 83,000	133,000	135,000	- 20,000	113,000	386,000	664,000
Building Rent	-	-	-	- 208,000	-	-	- 208,000
Appendix 2-N Administrative Shared Services From Affiliates	- 62,000	270,000	- 168,000	205,000	- 11,000	169,000	403,000
Maintenance of Overhead Servi	-	-	86,000	- 83,000	54,000	-	57,000
Outages	383,000	- 274,000	- 76,000	- 145,000	133,000	69,000	90,000
ROW Vegetation Maintenance Program	23,000	244,000	- 17,000	202,000	- 23,000	816,000	1,245,000
Meter Expenses	- 112,000	- 14,000	15,000	10,000	37,000	6,000	- 58,000
Travel Costs	- 85,000	- 8,000	49,000	33,000	-	-	- 11,000
Miscellaneous	- 213,547	- 116,405	237,529	129,628	- 173,015	86,542	- 49,268
Closing Balance[2]	13,356,735	13,608,330	13,901,859	13,993,487	14,606,472	16,319,014	2,630,732

Cost of Capital

In this application, API seeks to recover a weighted average cost of capital of 7.06 %through rates in the 2025 Test Year. API has followed the Report of the Board on Cost of Capital for Ontario's Regulated Utilities, December 11, 2009 in determining the applicable cost of capital.

In calculating the applicable cost of capital, API has used the OEB's deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, in conjunction with the cost of capital parameters in the OEB's letter of October 31, 2023, for the deemed short term debt rate and allowed return on equity. The following table summarizes API's capital structure, cost of capital, and the associated return on rate base included in its 2025 revenue requirement.

Table 12 - Overview of Capital Structure and Cost of Capital

	Capitalization Ratio		Cost Rate	Return
	%	$	%	$
Debt				
Long-term Debt	56.00%	$ 99,566,021	5.59%	$ 5,562,662
Short-term Debt	4.00%	$ 7,111,859	6.23%	$ 443,069
Total Debt	60.00%	$ 106,677,879	5.63%	$ 6,005,731
Equity				
Common Equity	40.00%	$ 71,118,586	9.21%	$ 6,550,022
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$ 71,118,586	9.21%	$ 6,550,022
Total	100.00%	$ 177,796,465	7.06%	$ 12,555,753

API acknowledges that the OEB may adjust the cost of capital parameters applicable to rate changes effective in 2025, and therefore expects to update the applicable deemed rates when the OEB issues the revised 2025 parameters. Furthermore, API expects to update assumptions related to its upcoming debt issuance once the actual interest rate and other details are finalized.

Cost Allocation and Rate Design

API has prepared and is filing a 2025 Cost Allocation Study consistent with its understanding of the Directions and Policies in the Board's Reports of November 28, 2007 Application of Cost Allocation for Electricity Distributors and March 31, 2011 Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) (the "Cost Allocation Reports") and all subsequent updates.

Consistent with past cost of service applications, the 2025 cost allocation study is based on the use "equivalent rates" for the R1 and R2 rate classes. These are the rates which would apply in the absence of RRRP funding, as further explained in Exhibits 7 and 8.

Since the 2025 status-quo ratios for the Street Lighting and Seasonal rate classes are each below the lower limit of the applicable OEB policy range, API proposes to adjust the 2025 ratios as shown in the following table, phasing in the adjustments in order to mitigate the rate impacts on those classes. (note: the full 5-year transition plan for Street Lighting can be found in Exhibit 8):

Table 13 – Rebalancing Revenue to Cost Ratios

Name of Customer Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year:	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	2020			
	%	%	%	%
Residential	104.65%	102.31%	102.31%	85 - 115
Residential R2	93.54%	112.25%	108.56%	80 - 120
Seasonal	85.44%	74.63%	79.81%	85 - 115
Street Light	120.00%	44.00%	51.20%	80 - 120

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
			1	2	
1	Residential	102.31%	102.31%	102.31%	85 - 115
2	Residential R2	108.56%	104.88%	104.33%	80 - 120
3	Seasonal	79.81%	85.00%	85.00%	85 - 115
4	Street Light	51.20%	58.40%	65.60%	80 - 120

API's rate design is unique in that its R1 and R2 rate classes benefit from funding provided through RRRP payments to API. The determination of the annual RRRP payment can be summarized as follows:

1. Determination of the amount of API's revenue requirement that is allocated to its RRRP-eligible rate classes;

2. Determination of the forecasted distribution rate revenue from API's RRRP-eligible rate classes, considering the most recently approved distribution rates adjusted by the RRRP Adjustment factor; and

3. Calculation of the annual RRRP amount payable to API as the amount by which the revenue requirement identified in Step 1 exceeds the revenue forecasted in Step 2.

API's proposed 2025 rate design in the context of the RRRP framework is detailed in Section 8.2 of Exhibit 8. API confirms that the proposed approach to 2025 rate design is consistent with the approach approved by the OEB in API's prior cost of service applications. Certain API customer groups also benefit from the Distribution Rate Protection or First Nation Delivery Credit, however these programs do not require significant rate design methodology adjustments.

As a mitigation measure further detailed in Exhibit 8, API is proposing to defer the 2025 fixed-variable adjustment towards fully fixed rates for Seasonal customers. Additionally, API has proposed to phase in the move towards the OEB's lower revenue to cost ratio boundary for both the Seasonal and Street Lighting classes to address bill impact mitigation.

API is further proposing to adjust the monthly billing unit for the street lighting class from number of connections to number of devices, as further detailed in Exhibits 7 and 8.

The table below shows APIs existing rates in comparison to the 2025 proposed rates:

Table 14 – 2025 Proposed Distribution Rate Summary

Rate Class and Charge	Unit	2024 Approved	2025 Proposed
Residential - R1(i)			
Monthly Service Charge	$	64.31	$ 66.59
Distribution Volumetric	$/kWh	0	$ -
Residential - R1(ii)			
Monthly Service Charge	$	28.84	$ 29.86
Distribution Volumetric	$/kWh	0.0406	$ 0.0420
Residential - R2			
Monthly Service Charge	$	742.06	$ 768.33
Distribution Volumetric	$/kW	3.845	$ 3.9811
Seasonal			
Monthly Service Charge	$	82.79	$ 97.58
Distribution Volumetric	$/kWh	0.0384	$ 0.0453
Street Lighting			
Monthly Service Charge (per device)	$	2.08	$ 2.68
Distribution Volumetric	$/kWh	0.3361	$ 0.4338
RRRP Funding Requirement		$ 17,174,943	$ 21,173,234

Deferral and Variance Accounts

API proposes to dispose of a credit of $135,071 related to Group 1 and a credit of $1,957,987 related to Group 2 Variance/Deferral Accounts. These credit balances include carrying charges up to and including December 31, 2013, as well as interest projected to December 31, 2024.

Group 1 and Group 2 DVA balances are proposed to be disposed of over a period of 12 months.

Further details are outlined in Exhibit 9 of this Application.

In its most recent IRM applications, API has not disposed of the balances in its accounts 1588 and 1589, pending investigations to reconcile the account balances within the OEB's acceptable range. Working with a third party consultant, API has now completed these investigations and has made proposals in Exhibit 9 to adjust the 2021 and 2022 account balances, and dispose of these balances. Included in this proposal is a request for the OEB to issue an Order to the IESO to accept the settlement of past Class A amounts.

API has not proposed to dispose of the 2023 activity in Accounts 1588 and 1589, pending further validation of its 1588/1589 activity. Based on API's billing process, there is no Global Adjustment ("GA") variance for Class A customers. For Class B customers, OEB Account 1589 captures the difference between GA amounts billed to non-RPP customers and the actual GA amount paid for those customers to the IESO. The rate rider for disposition of OEB Account 1589 is therefore applicable to Class B non-RPP customers only. API applied historical RPP/non-RRP percentages to the 2025 load forecast amounts to arrive at estimated non-RPP kWhs for calculation of the 2025 rate rider. Special adjustments were made to address the expected nature of the load increase in the R2 class. An allowance was also made to allocate a portion of the Account 1589 balance to calculate a separate rate rider for one customer that transitioned between Class A and B in 2021.

API has also proposed two new accounts in Exhibit 9, related to the Defined Benefit Pension Plan and Land Use costs. Further information, including draft accounting orders, is included in Exhibit 9.

API has proposed to discontinue the following accounts:

- 1508-Dubreuilville Costs and Revenues
- 1508-Retail Service Charges
- 1508- ICM sub accounts for SSM Facility and ERTS
- 1576-Accounting Changes Under CGAAP Balance+Return Component.

Table 14 on the following page summarizes the DVA balances sought for disposition in 2025. Exhibit 9 provides detailed calculation of the resulting rate riders, all of which have been factored into 2025 bill impact calculations as applicable.

Table 15 – DVA Balances Sought for Disposition

Account Descriptions	Account Number	Total $ Claim	Allocator
Group 1 Accounts			
LV Variance Account	1550	-	N/A
Smart Metering Entity Charge Variance Account	1551	(23,550)	# of Customers
RSVA - Wholesale Market Service Charge5	1580	(292,020)	kWh
Variance WMS – Sub-account CBR Class A5	1580	-	N/A
Variance WMS – Sub-account CBR Class B5	1580	29,044	kWh
RSVA - Retail Transmission Network Charge	1584	1,507	kWh
RSVA - Retail Transmission Connection Charge	1586	106,567	kWh
RSVA - Power (excluding Global Adjustment)4	1588	383,065	kWh
RSVA - Global Adjustment 4	1589	(292,802)	Non-RPP kWh
Disposition and Recovery/Refund of Regulatory Balances (2021)3	1595	(46,882)	%
Total Group 1 Accounts		**(135,071)**	
Group 2 Accounts			
Pole Attachment Revenue Variance5	1508	296,246	Distribution Rev.
Other Regulatory Assets - Sub-Account - Dubreuilville Costs & Revenues	1508	(65,190)	kWh
Other Regulatory Assets - Sub-Account - Retail Service Charges	1508	(3,133)	kWh
Other Regulatory Assets - Sub-Account - Amortized Pension Actuarial Gains/Losses	1508	226,148	kWh
Other Regulatory Assets - Sub-Account - Amortized OPEB Actuarial Gains/Losses	1508	(258,334)	kWh
Other Regulatory Assets, Sub-account ACM True-up	1508	(1,307,910)	kWh
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges8	1522	(313,498)	kWh
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	(286,716)	kWh
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes12	1592	(310,790)	kWh
		-	N/A
LRAM Variance Account4	1568	-	N/A
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential8	1522	(1,841,912)	kWh
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account8	1522	1,841,912	kWh
Accounting Changes Under CGAAP Balance + Return Component	1576	84,971	kWh
Total Group 2 Accounts		**(1,938,206)**	

Bill Impacts

A summary of the bill impacts by class is presented in Table 15 below. Detailed explanations of the bill impacts are presented in Section 8.3.13 of Exhibit 8. Neither a rate plan nor a mitigation plan are required as all of API's bill impacts fall below the 10% threshold.

Table 16 – 2025 Bill Impact Summary

RATE CLASS/Usage Scenario	Units	Commodity Supply	Consumption (kWh)	Demand kW (if applicable)	Fixed Charge Billing Det.
Residential R1(i)	kwh	RPP	750		1
Residential R1(ii)	kwh	RPP	2,000	-	1
Residential R2	kw	Non-RPP (Other)	225,000	500	1
Seasonal	kwh	RPP	200		1
Seasonal-10th percentile	kw	Non-RPP (Other)	3,000		75
Street Lighting	kwh	RPP	15	10	1

	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
Classification	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Residential R1(i)	$ (6.05)	-14.61%	$ (7.65)	-14.94%	$ (9.87)	-14.83%	$ (9.23)	-6.35%
Residential R1(ii)	$ (2.23)	-2.02%	$ (6.51)	-4.80%	$ (12.42)	-7.04%	$ (11.59)	-3.00%
Residential R2	$ (1,439.43)	-54.42%	$ (6,915.23)	-198.66%	$ (7,447.44)	-105.22%	$ (8,309.25)	-24.31%
Seasonal	$ 10.48	10.95%	$ 10.18	10.33%	$ 9.58	9.34%	$ 8.98	7.58%
Seasonal-10th percentile	$ 9.24	10.42%	$ 9.22	10.33%	$ 9.17	10.24%	$ 8.59	10.02%
Street Lighting	$ 218.18	17.11%	$ 155.19	12.18%	$ 147.50	11.12%	$ 139.38	8.99%

	Distribution				Total Bill			
Classification	**Current Bill**	**2025 Propose**	**Change ($)**	**Change (%)**	**Current Bill**	**2025 Propose**	**Change ($)**	**Change (%)**
Residential R1(i)	$ 41.39	$ 35.34	$ (6.05)	-14.6%	$ 145.34	$ 136.11	$ (9.23)	-6.35%
Residential R1(ii)	$ 110.04	$ 107.81	$ (2.23)	-2.0%	$ 386.22	$ 374.63	$ (11.59)	-3.00%
Residential R2	$ 2,644.81	$ 1,205.38	$ (1,439.43)	-54.4%	$ 34,173.69	$ 25,864.44	$ (8,309.25)	-24.31%
Seasonal	$ 95.75	$ 106.23	$ 10.48	10.9%	$ 118.42	$ 127.41	$ 8.98	7.58%
Seasonal-10th percentile	$ 88.65	$ 97.88	$ 9.24	10.4%	$ 85.80	$ 94.39	$ 8.59	10.02%
Street Lighting	$ 1,275.00	$ 1,493.18	$ 218.18	17.1%	$ 1,549.84	$ 1,689.23	$ 139.38	8.99%

The credit Group 2 rate riders contribute a reduction for all customer classes, with significant impacts in the Residential R1(i), R1(ii) and Residential R2 customer classes. The primary driver of the large total bill decreases for the non-RPP rate classes is a relatively high credit rate rider related to disposition of Global Adjustment variances. For the Seasonal and Street Lighting classes, the increased allocated revenue requirement has resulted in initial bill impacts which required mitigation measures. At the currently proposed levels the total bill impacts remain at or below the mitigation threshold of 10%.

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1.6 MATERIALITY THRESHOLD

In accordance with the Minimum Filing Requirements and given that API's revenue requirement falls within the $10 million to $200 million range, the following materiality threshold has been calculated.

Table 17 – Materiality Calculation

Base Revenue Requirement	Percentage	Materiality Threshold
$ 35,112,551	0.50%	$ 175,563

Based on the above, API has used $175,000 as a materiality threshold throughout this Application.

1.7 CUSTOMER ENGAGEMENT

1.7.1 OVERVIEW OF CUSTOMER ENGAGEMENT

Ongoing Customer Engagement

API strives to continue providing services that are valued by its customers, in a safe and cost-effective manner. This requires understanding customers' current and future needs. It also requires a culture of embracing continuous improvements in the services API provides, especially within the customer experience. Accordingly, API has implemented a comprehensive customer engagement program, which continues to evolve in meeting both customer and OEB expectations.

API's goal is to demonstrate a focus on long term value to customers and in turn raise confidence through both education and solicitation of customer feedback. This will lead to the successful implementation of projects that customers consider meaningful.

Significant work has gone into customer engagement activities using various methods and communication channels, which are necessary given the unique geography of API's 14,200 square kilometre service territory. Customers, stakeholders and third parties alike have unique requirements and API recognizes that a "one size fits all" approach to engagement is not effective. The following subsections provide detail of API's customer engagement activities across the following categories: Customer Satisfaction Surveys, Community Outreach/Stakeholder Sessions, Forestry Outreach, and Other Supporting Engagement Activities. The complete list of customer engagement activities has been populated in the OEB's Appendix 2-AC, which is included as Attachment 1E to this Exhibit.

Annual Customer Satisfaction Surveys

API has engaged UtilityPULSE annually to conduct independent telephone and online based customer satisfaction surveys. The survey asks questions of both residential and general service customers on a wide range of topics, including: (a) power quality and reliability; (b) price; (c) billing and payment; (d) communications; and (e) the customer service experience. UtilityPULSE typically conducts the survey in the fall of a given year, with final results available in December. The results are compiled into a final report outlining the overall level of customer satisfaction within API's service area, as well as benchmarking the results against other Provincial and National participants. These results are then used to support internal discussions surrounding what is currently being done well, and what needs improvement. The following table provides a summary of overall satisfaction results:

Table 18 – Customer Satisfaction Survey Results – 2020-2023

Customer Satisfacation Surveys

	2023			2022			2021			2020		
	API	National	Ontario	API	National	Ontario	API	National	Ontario	API	National	Ontario
Overall Satisfaction (%)	90	91	92	97	92	90	95	93	92	94	94	93
Customer Experience Performance Rating (%)	85	82	82	85	83	82	88	84	85	88	86	86

Overall customer satisfaction has generally increased during the 2020-2023 period, and has remained consistently above 90% and typically above the Ontario average. The survey provides direct feedback and assists API with identifying opportunities for improvement. Overall satisfaction denotes a consolidated opinion of services provided to the customers. Customer experience performance rating ("CEPr") is a combination of two key attributes: professional customer care and quality of services. This metric answers basic questions such as "does the organization effectively meet your needs?" and "does the organization provide high- quality services". Given scores continue to track at 85% and above, consistently ranking above both the Ontario and National scores, this provides an indication that API is actively listening to customer needs and providing service levels that meet their expectations.

Community Outreach/Stakeholder Sessions

This form of engagement is very important to API's understanding of community and customer needs through face-to-face interaction.

Annually, API's annual stakeholder session includes topics such as current customer service initiatives, public safety, conservation demand management updates, incentives, community growth, operations maintenance, and capital projects. 18 municipal councils, planning boards and First Nation councils within its service territory are contacted to schedule attendance at one of their regularly scheduled council or planning board meetings. Each presentation provides the councils with updates and encourages dialogue on a number of levels. The operational topics discussed are tailored to each municipality. Councils have commented positively on the value these presentations provide.

API also hosts an Annual Contractor Safety Night with local electrical contractors and invites the local office of the Electrical Safety Authority (ESA). The event includes discussions on Public Safety issues, Customer Service topics, and API's customer connection process. It is open forum for interactions between API and the contractor community.

Annual Road Superintendent Meeting

This event brings together API Operations staff with local Townships, Road Boards agencies, and the MTO. API presents short-term and longer-term capital and maintenance outlooks for the next three years to the participants with broad descriptions of the scopes of work. The intent of the discussion is to share work program locations and timing to find synergies in the workflow or ways to avoid conflicting work schedules and project timing.

Safety issues related to road maintenance are also discussed, highlighting working clearances to energized conductors and ditching activities in very close proximity to API's circuits. The meeting also features an open general discussion to address specific operations issues of importance to attendees.

Forestry Outreach

The API service territory has a large amount of diverse vegetation. This generates considerable awareness among customers in how the organization manages that vegetation and related habitat stewardship. Historically, API has held annual sessions dedicated to vegetation management, in the communities where the work is being performed. Unfortunately, during the pandemic, API was unable to hold these sessions, however API plans to reinstate this process in 2024 and beyond. Topics around how right of ways are maintained and other API-specific distribution system elements affected by vegetation were shared with customers. These sessions gave customers an opportunity to ask questions and cite concerns, which API takes into account when planning related activities.

Conservation and Demand Management ("CDM")

The Save on Energy program is promoted in interactions with business customers and API's communities. Following changes to the responsibilities for conservation framework delivery, API no longer has any resources dedicated to CDM programs, however API staff are able to refer interested customers to the appropriate IESO contacts.

Other Supporting Engagement Activities

API is a relatively small LDC in terms of its customer base, with approximately 12,000 customers dispersed across a large service area, and as such API has in place a wide range of activities to engage customers. Beyond what has been summarized above, the following is a list of six additional customer engagement activities that support customer outreach and engagement across a variety of platforms.

Social Media (Outage Communication) – API provides Twitter and Facebook updates on planned outages as well as periodic updates during significant storm events. Since API customers also interact with the 24x7 call centre, ongoing dialogue will continue to ensure alignment of communication methods with customer preference is maintained.

Website (General Communication) – The API website (www.algomapower.com) provides a constant flow of updated customer-centric information. Topics such as distribution services, rates, regulatory matters and decisions, planned outages, and marketing campaigns are made available in this one-stop location. Customers have requested additional ways to communicate with API and online webchat is now offered. Email inquiries also continue to increase each year. This communication allows API to answer customer inquiries that occur at times that are convenient to its customers.

Technology Based – Currently, API's portal is available to customers that create an account and provides time-of-use based consumption information. Additionally, billing information, payment options, and ability to change their telephone and address information is provided. Increased portal uptake has occurred over the last few years due to ongoing campaigns and by implementing a more user-friendly version. E-forms are available to assist customers to move out or transfer to a new premise 24/7. API offers an outage map, which displays outage information for customers to access via their smartphones, tablets, or computers. API plans to implement text based outage notifications in 2024. In prior surveys, API customers have expressed an interest in receiving this type of enhanced outage communication.

Front Desk Support – API currently maintains front desk support, by appointment, allowing the customer and the utility to interact on a direct basis. Data gathered through these interactions can then be used to improve business outcomes. In this sense, front desk staff becomes pivotal to the business and bridges the gap between the customer and other utility staff. API plans on continuing its front desk operations as a form of customer engagement and to ensure expected customer service levels are maintained. Customers can email, phone in or utilize webchat with front desk support. In late 2022, API began offering On-Line forms for 24/7 customer access.

Publications – The majority of API's customers receive a physical bill in the mail, and API takes advantage of this opportunity to communicate additional information via messages on the outside of the envelope, separate inserts, and messages on the bill itself. Many of these messages are coordinated with announcements from the OEB, IESO, and other agencies, and include information about retailers, rate changes, conservation and demand management programs, electrical safety, and references to API's website. API also publishes a newsletter (twice per year), which gives information and updates on the industry and/or explains how costs/rates are determined.

Social Services – Financial Assistance Program: Algoma Power Inc. provides support through partnerships with the Low-income Energy Assistance Program (LEAP) program. API has works with Algoma District Services Administration Board ("ADSAB"), as further described in Exhibit 4. Programs of this type are designed to help low-income customers who have difficulty making their electricity bill payments and are regularly communicated to API customers via all media channels.

Application-Specific Customer Engagement

In the process of preparing this Application, API worked with a third party research firm (Innovative Research Group) to facilitate the 2025 – 2029 rate application customer engagement. This involved customer workbook surveys intended to gain feedback from the four primary customer categories; Residential, Seasonal, Small Business and Large Business. Each rate classification received a separate survey format containing the same questions[1], but reflecting bill and consumption levels appropriate to the rate class.

The response rate for the survey was very successful, with nearly 1,400 of API's 12,500 customers responding to the survey. This indicated that the response feedback is considered statistically representative of API's customer base, and significantly exceeded API's target response rate.

In planning for the future six key projects were asked in the workbooks to support participating customers' ability to make choices representative of rate impacts and ultimately drive Algoma Power Inc.'s spending decisions. The six projects were as follows:

- Pole and Line Replacement
- Substation Rebuild
- Voltage Conversion
- Preparing for increased electricity demand
- Automated "intelligent" switches
- Vegetation Management

For each of these projects, API outlined its proposed approach (and associated estimated cost impacts), as well as alternative options (with associated alternative cost impacts).

For all customer classes, the largest proportion of customers supported implementing the projects as originally proposed by API, as shown in the table below (an excerpt from the Innovative Research Report). A final question allowed customers to assess the cumulative impact of the overall plan, which most customers once again supported "spend according to draft plan".

Please note in the first column of the tables below, the option highlighted in dark blue represents API's originally proposed option.

[1] Additional questions were included in the survey for Large Customers requesting information on their electrification planning.

1 **Table 19 – Summary of Customer Feedback on Survey Programs**

	Residential [n=1,000]	Seasonal [n=350]	Small Business [n=35]	Large Business [n=7]
Pole and Line Replacement				
Accelerated pace	24%	20%	9	1
Current approach	62%	60%	22	5
Slower pace	14%	19%	4	1
Substation Rebuild				
Like-for-like capacity	15%	21%	5	2
50% capacity increase	47%	58%	19	5
100% capacity increase	38%	21%	11	-
Voltage Conversion				
Minimum level	13%	21%	2	2
Mid level	54%	54%	27	5
Full level	33%	25%	6	-
Preparing for Increased Electricity Demand				
Status quo	38%	55%	18	5
25% proactive replacement	44%	30%	13	2
50% proactive replacement	18%	16%	4	-

2

	Residential [n=1,000]	Seasonal [n=350]	Small Business [n=35]	Large Business [n=7]
Automated "Intelligent" Switches				
Status quo	17%	24%	5	1
Partial implementation	27%	32%	15	2
Full implementation	56%	43%	15	4
Vegetation Management				
Reduced cycle approach	13%	15%	4	1
Standard cycle approach	67%	67%	22	5
Increased cycle approach	21%	19%	9	1
Overall Plan Evaluation				
Spend more	33%	21%	10	1
Spend according to draft plan	52%	52%	19	5
Spend less	5%	17%	5	1

Additionally, customers provided the following feedback regarding their priorities for API:

Figure 5 – Summary of Customer Feedback on Priorities

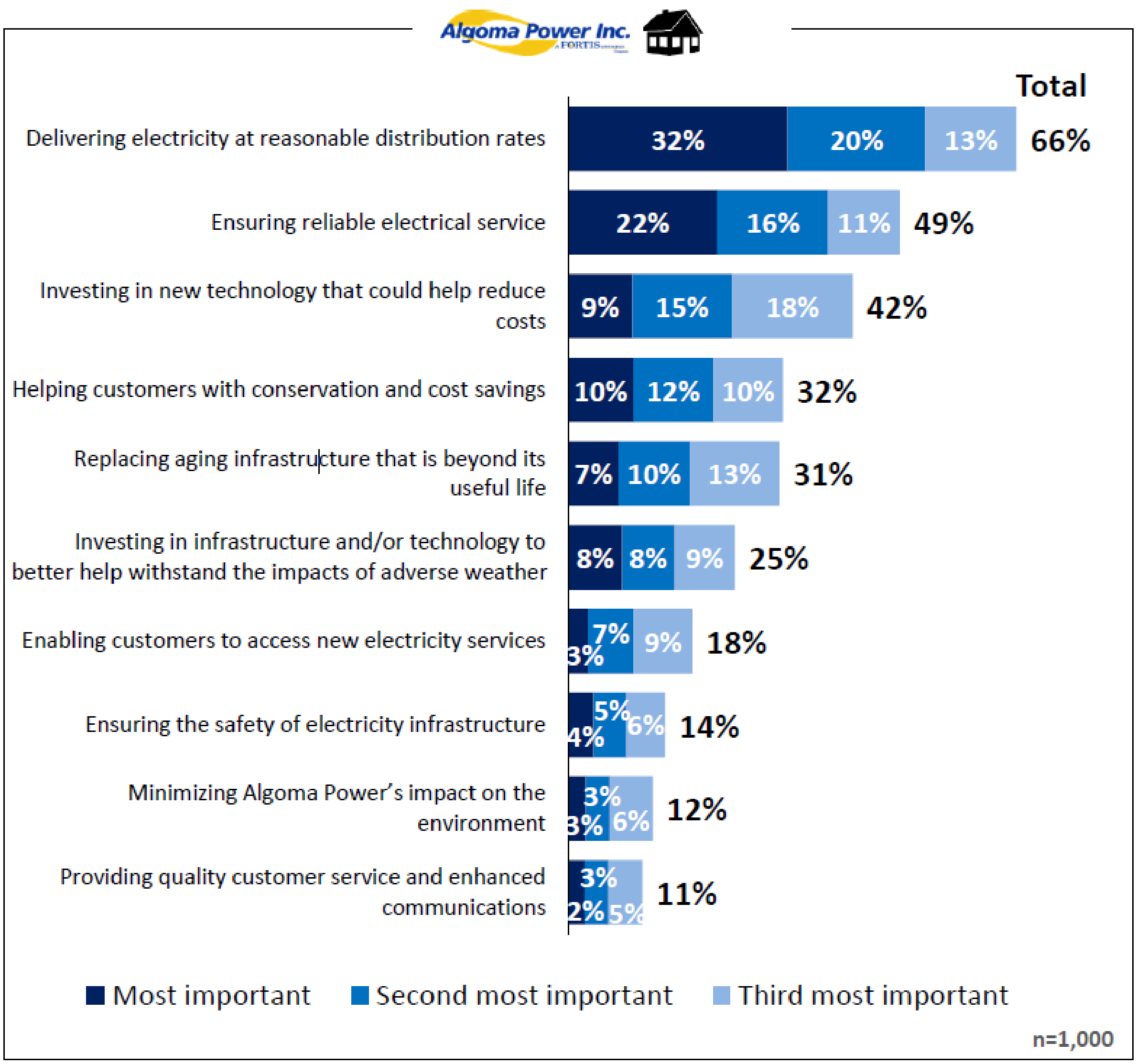
Q

As with all businesses, Algoma Power must make decisions on which areas they are going to prioritize within their business plans.

Based on ongoing conversations with customers, a number of company goals have been identified as priorities for Algoma Power.

Looking at the list below, please rank your top 3 priorities—where "1" would be the most important, "2" the second most important, and "3" the third most important.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, and ending with the third most important.



As shown above, reasonable distribution rates and reliable electrical service were highest-priority objectives.

The complete Innovative Research report results can be found in Attachment 1I of the application.

Consultation with Specific Customer Groups

API specifically included Seasonal customers as a separate segment to be surveyed with Seasonal-specific rate impacts. As a non-RRRP protected rate classification, the Seasonal rate class bill impacts are more directly tied to the proposals in this Rate Application. API received a strong level of response from Seasonal class customers, and the customer preferences on individual projects were consistent with other classes. In the final question of the survey, a majority of customers indicated API should "spend according to plan" when asked about the overall plan evaluation.

API also consulted directly with its Street Lighting customers through direct outreach, consistent with its commitment in its Conditions of Service. In its outreach, API informed its street lighting customers about the upcoming Cost of Service and indicated the expected street lighting bill impacts. API also provided each customer with a summary of the billing units on record (ie: number of devices), and provided the customers the opportunity to update their information in the case of any discrepancies.

1.7.2 IMPACT OF CUSTOMER ENGAGEMENT

Impact of Customer Feedback on API Operations

As customer demographics change, API understands that online support is expected and will continue developing and offering On-Line forms for 24/7 customer access.

Through API's customer satisfaction survey, customers have requested outage information on a more frequent basis. API now offers an outage map, which displays outage information for customers to access from their smartphones, tablets, or computers. Text based notifications will also be pushed to subscribed customers in 2024.

Impact of Customer Feedback on the Application

Section 4 of API's Business Plan describes how API continues to improve in understanding the needs and expectations of its customers, and how API's core values, the needs of its customers, and the OEB's RRF outcomes are integrated and prioritized in its planning activities.

API's proposals for each of the programs in the consultation are aligned with customers' preferences.

For the question regarding "preparing for increased electricity demand", most customers surveyed supported API's current "status quo" proposal, however many customers, particularly in the Residential customer class also supported a 25% percent proactive transformer replacement in advance of anticipated changes in electricity use due to electrification. API will proceed with the status quote, as preferred by the majority of customers, but will also consider opportunities for upgrading transformer capacity when coordinating with other project work, and when it is cost-effective to do so.

Additionally, API's Customers identified cost control and reliability investments as their top priorities for API.

The following table highlights how each major project addresses each of these priorities:

Table 20 – Summary of Projects Addressing Reliability and Cost Control

	Reliability and Resilience improvements	Cost Effectiveness
Service Connections	N/A	Work is completed in coordination with other requirements, where possible, to minimize mobilization costs.
Small Lines/Stations Capital	•Replacing deteriorated assets prior to failure allows API to reduce or eliminate the outage impact of an unplanned outage.	Proactive replacement can be associated with lower costs, ex: due to planned work during regular hours.
Smart Meter Replacement	API's smart metering network supports its outage identification and management.	•Proactive replacement approach promotes cost-effective replacements. •API's long-term goal is to create a chronologically diverse reverification batch size that stabilizes annual costs •Proactive approach allows API to optimize use of internal resources.
Wawa #2 DS	•Aged transformer presents reliability risk; failure would leave Wawa without backup. •Current station design requires total de-energization of the station for switching or equipment failures.	•"Right Sizing" today will help avoid costly upgrades in the future to address load growth. •New station design will allow API to operate the DS in a more cost-efficient manner.
Goulais TS Refurbishment & Voltage Conversion	Investment will support improved voltage reliability and stability	•API has chosen a balanced approach, the "medium" scenario of voltage conversion. •The voltage conversion plan will result in avoided costs for dual-voltage HOSSM transformer, and API owned station. •Investments in Goulais TS will limit future investments due to long term growth.
Distribution and Subtramsmission Line Rebuilds	• Reliability and resilience are supported through replacement of older, deteriorated assets with new assets, which inherently are less likely to fail. •Proactive asset replacement minimizes outage impact and duration as unplanned outages can take significantly longer to restore. •Reliability and resilience are further supported through the updating of assets to today's higher standards.	•Lifespan optimization reduces risk of early writeoffs. •Lifespan optimization supports long-term program cost stability and avoids higher future costs. •Planned approach allows API to optimize use of internal resources. •Planned, proactive approach allows API to minimize costly "one-off" replacements. •Planned proactive approach has been historically successful at avoiding unplanned pole failures, which can be significantly more costly to address.
Protection, Automation, Reliability	Projects have been selected to address the highest opportunities for reliability improvements.	•Many projects will have a positive impact on system losses and enable future cost savings. •Incorporation of advanced SCADA-capable equipment will support operational and asset management efficiences.
Vegetation Management	•VM program has contributed to steady improvements in the number and duration of outages. •Tree caused outages will continue to be the #1 outage source in API's territory •VM activities help avoid outages during some extreme weather events, and enable crews to restore power when outages do occur. •VM practices are designed to mitigate Wildfire risks.	•API's VMP is designed with optimal cycle durations that ensure control is maximized, avoiding long term cost increases. •Despite increasing challenges as a result of reduced ability to apply herbicide as well as inflationary increases, API has incorporated cost efficiency targets into its 2025 budget.

1.8 LETTERS OF COMMENT

1.8.1 LETTERS OF COMMENT

API has not received any letters from its customers related to this application as of the filing date. API is, however, committed to responding to matters raised in letters of comments during the proceeding and will file all customer letters related to the application, along with API's response.

1.9 PERFORMANCE MEASUREMENT

1.9.1 SCORECARD RESULTS AND ANALYSIS

Section 5 of API's Business Plan outlines API's performance for each of the scorecard measures over the last five years, explains future targets for each measure, and where applicable describes how past performance and/or future targets have affected the proposals in this Application and DSP. The Business Plan is included as Attachment 1B. Additionally, API's 2022 scorecard and MD&A can be accessed at the link below:

Scorecard - Algoma Power Inc..pdf

Table 22 below shows API's 5-year most recent scorecard measure performance.

Table 21 – API Scorecard 2018-2023

Performance Outcomes	Performance Category	Measure	2019	2020	2021	2022	2023	Industry Target	API 2020-2024 Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	97.1%	100.0%	100.0%	98.6%	100.0%	90.0%	90.0%
		Scheduled Appointments Met On Time	100.0%	100.0%	100.0%	100.0%	100.0%	90.0%	90.0%
	Customer Satisfaction	Telephone Calls Answered On Time	81.6%	84.8%	88.4%	85.5%	78.3%	65.0%	65.0%
		First Contact Resolution	100.0%	99.9%	100.0%	100.0%	99.9%	no target	95.0%
		Billing Accuracy	99.9%	99.9%	99.8%	99.9%	99.9%	98.0%	98.0%
		Customer Satisfaction Survey Results	95.0%	94.0%	93.0%	97.0%	90.0%	no target	81.0%
Operational Effectiveness	Safety	Level of Public Awareness	83.0%	83.0%	83.0%	82.0%	82.0%	no target	80.0%
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C	C
		Serious Electrical Incident Index- Number of General Public Incidents	-	-	-	-	-	-	-
		Serious Electrical Incident Index- Rate per 10, 100,	-	-	-	-	-	-	-
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	7.33	6.79	3.61	4.43	5.25	5-year avg	7.36
		Average Number of Times that Power to a Customer is Interrupted	3.39	2.93	1.77	2.08	2.27	5-year avg	3.16
	Asset	Distribution System Plan Implementation Progress	Completed	Completed	Completed	Completed	Completed	no target	Completed
	Cost Control	Efficiency Assessment	5	5	5	5	5	no target	Improving Efficien
		Total Cost per Customer	$ 2,235	$ 2,212	$ 2,338	$ 2,479	$ 2,825	no target	Improving Efficiency
		Total Cost per Km of Line	$ 12,107	$ 12,203	$ 13,025	$ 14,501	$ 16,653	no target	
Financial Performance	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time	no longer presented						
		New Micro-embedded Generation Facilities Conne	100%			100%			
	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Lia	0.69	0.77	0.43	0.26	TBD	no target	no target
		Leverage: Total Debt (includes short-term and long-term debt)to Equity Ratio	1.36	1.3	1.32	1.44	TBD	no target	no target
		Profitability: Deemed Regulatory Return On Equity	9.30%	8.52%	8.52%	8.52%	8.52%	no target	no target
		Profitability: Achieved Regulatory Return On Equity	8.44%	9.25%	9.38%	10.53%	10.54%	no target	no target

A brief summary of the scorecard results is presented below:

<u>Service Quality</u>

Algoma Power has consistently exceeded the 90% minimum industry standard for new connections on time, with a five-year average of 99%. Scheduled appointments were met 100% on time throughout the five-year period.

Among the service quality metrics, telephone calls answered on time had the greatest range, however API has consistently achieved results exceeding 80% throughout the period, far exceeding the industry minimum standard of 65%. This metric may vary from year to year based on the number of phone calls received, and based on internal resourcing.

API strives to improve its service levels by offering more self-serve options to its customers, however the increasing complexity of customer inquiries has added new challenges; for example, a greater level of customer choice for RPP customers may result in longer call times with new customers and/or those considering a change of pricing plan.

API's goal is to maintain or exceed the strong performance levels in the coming years.

Customer Satisfaction

First contact resolution has remained stable throughout the period, consistently in the range of 99-100% annually. API measures first contact resolution on the basis of calls completed without escalation.

Billing accuracy performance has also consistently been in the 99-100% range, consistently exceeding the industry target of 98%.

Algoma Power goes beyond the customer satisfaction survey requirements by conducting a customer satisfaction survey annually instead of biennially.

API employs UtilityPULSE to complete the survey annually, which contains a consistent survey questionnaire on the core aspects of service delivery, as well as occasional "new"/ad-hoc survey topics. While the ad-hoc topics are not employed in the measurement of customer satisfaction, the responses to these questions may provide API with insights used for future planning. Customer Satisfaction is consistently a corporate KPI for API, reinforcing alignment with customer preferences. The UtilityPULSE provides a provincial benchmark of satisfaction, and it is API's goal to exceed this benchmark. As shown in Table ## above, API's customer satisfaction results tend to exceed the Ontario average.

Safety

API has a well-developed corporate safety program, which is further detailed in Exhibit 4, as well as the additional safety challenges faced by API due to the size and remoteness of its service area and distribution system. API's most recent 5-year safety performance indicates 0 (NIL) serious electrical incidents, and consistent compliance with Ontario Regulation 22/04. Public Awareness of Electrical Safety survey results consistently exceed 80%. This survey is completed by a third party on behalf of API every other year. The successful results can partially be attributed to API's safety awareness programs in the community.

Reliability

API's scorecard shows the average number of hours that power to a customer is interrupted (SAIDI) and the average number of times that power to a customer is interrupted (SAIFI). API's most recent SAIDI and SAIFI targets apply to 2020-2024, and are based on 2015-2029 performance. In 2020-2023, API has consistently performed favourably compared to the targets of 7.36 (SAIDI) and 3.16 (SAIFI). The improving reliability performance is attributable to API's capital and operating programs aimed at improving reliability, including aged asset replacements and vegetation management.

The scorecard measures for reliability exclude outages that are caused by loss of supply (ie: upstream in the electricity system, and outside of API's control), as well as Major Events (ie: weather events that exceed the standards which the distribution is designed to sustain).

Distribution System Plan Implementation Progress

On an annual basis, API reviews its progress compared to the distribution system plan in order to make an assessment of the year's accomplishments. Considerations include the completion and timing of key projects, the management of projects in a safe and environmentally sound manner, and adherence to annual and cumulative budget. Developments outside of API's control are also factored in, such as the need to reprioritize projects in response to higher-than-expected customer connection requests, emerging risks identified through ongoing inspections and testing that were not apparent at the time of initial project prioritization, etc. Considering all of these factors, API assesses DSP implementation each year as "Complete" or "Incomplete". The assessment is reported annually on API's distribution scorecard. For the historic period, API has assessed the annual DSP Implementation measure as consistently "Complete".

Cost Control

Pacific Economics Group (PEG) issues a total cost benchmarking and efficiency assessment annually, which assesses the performance of all Ontario LDCs. PEG also assesses a total cost for each distributor, which is also shown divided by the number of customers and km of line, to provide unit based metrics.

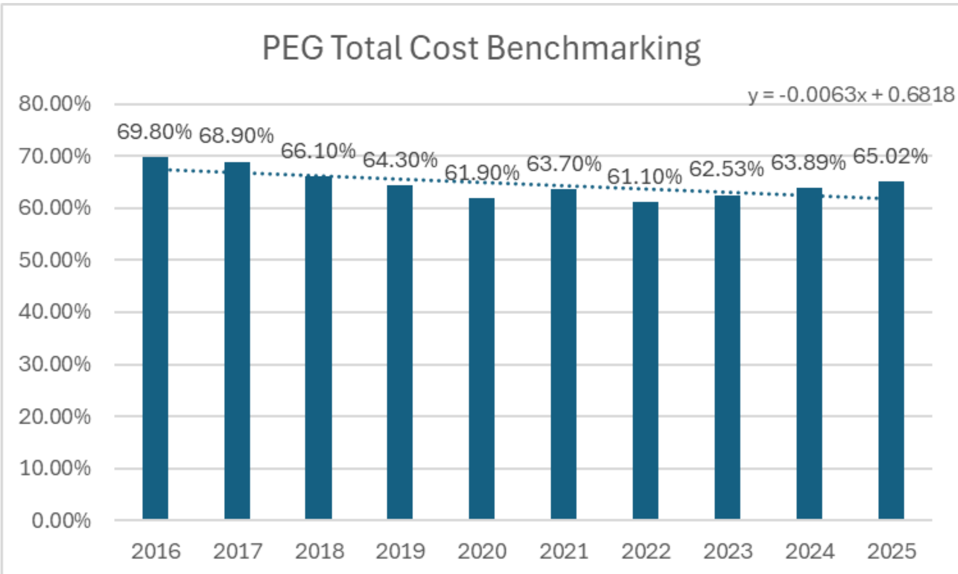
API's total cost per customer has increased by an average of 6% per year and total cost per km of line has grown at an average of 8% per year. These figures reflect inflationary and other cost drivers outlined in this Application, versus a relatively limited growth in the number of customers, and an overall decrease over the period in km of line.

As outlined below, API is an outlier compared to most other Ontario LDCs due to its extremely low customer density and the rugged and remote nature of its service territory. The section below compares API's benchmarking efficiency assessment over time, and demonstrates API's continuous improvement in cost control over 2016-2025.

1.9.2 TOTAL COST BENCHMARKING

API's historical and forecasted efficiency assessment for the 2016-2025 period, using the OEB's Benchmarking Forecast Model, is shown below:

Figure 6 – PEG Total Cost Efficiency Assessment



API's year over year overall trend for the period presented above shows a long-term decreasing trend, with an increase in 2025 related to the increase in OM&A.

With respect to the efficiency assessment in the PEG model, API has consistently remained in cohort 5. For the reasons summarized in Section 5.1 of the Business Plan, API does not believe that the PEG model cost predictions accurately reflect the cost drivers inherent to API's distribution system and service area. Since API's inputs to the PEG Model remain relatively stable year-over-year however, the trending in cost performance provides useful insight into whether API's cost efficiency is improving over time. The 2016-2025 ten year trend indicates that API is becoming more efficient over this period. Annual variations in the results can be caused by one-time costs in capital and OM&A, and as such API is focused on longer term overall trending which demonstrates continuous improvement.

1.9.3 ACTIVITY AND PROGRAM BENCHMARKING

In recent years, the OEB has published annual updates to its Activity and Program Benchmarking (APB) reports. The reports are based on financial and other data reported annually to the OEB, and assess a representative cost per unit in ten significant programs. Unlike the Total Cost Benchmarking, the APB does not consider the LDC's robust costs. Distributors may use the report to monitor their own performance in the programs covered over time, or may use the report to compare costs for these activities with the rest of the sector.

Many factors can affect a distributor's performance in comparison to the sector. While some of the factors are within the distributor's control, other factors affecting cost levels per unit are not. Therefore, a distributor's unit costs compared to industry may or may not reflect distributor's cost-effectiveness. For API, a significant example of this is Vegetation Management, which is further described below.

The table below shows the unit cost benchmarking from 2018-2025. 2018-2022 figures are based on the OEB's most recent APB report. For these years, the Industry Average cost for each activity/program has been presented. The figures for 2023-2025 in the table are based on API forecasts. The forecast figures primarily reflect forecasted changes in the cost(numerator) per program, but not the units (denominator).

Table 22 –Summary of Activity and Program Benchmarking Results

	Most Recent APB Report							Forecast		
Activity/Program	**2018**	**2019**	**2020**	**2021**	**2022**	**2018-2022 Avg**	**Industry Avg 2018-2022**	**2023**	**2024**	**2025**
Billing ($/customer)	$ 13.62	$ 16.21	$ 18.78	$ 16.65	$ 15.41	**$ 16.14**	**$ 26.43**	$ 16.48	$ 20.19	$ 20.49
Metering O&M ($/customer)	$ 74.85	$ 74.85	$ 74.85	$ 74.85	$ 74.85	**$ 74.85**	**$ 13.96**	$ 79.28	$ 79.12	$ 75.83
Vegetation Management O&M ($/pole)	$ 119.15	$ 118.80	$ 124.03	$ 133.71	$ 132.10	**$ 125.56**	**$ 67.76**	$ 139.10	$ 138.29	$ 166.48
Lines O&M ($/circ. km Prim. Line)	$ 529.73	$ 773.46	$ 649.35	$ 791.34	$ 650.85	**$ 678.94**	**$ 1,042.09**	$ 672.33	$ 837.10	$1,093.89
Stations O&M ($/MVA)**	$ 718.11	$ 524.59	$ 281.52	$ 696.90	$ 589.27	**$ 562.08**	**$ 1,399.12**	$ 520.28	$ 823.81	$1,072.16
Poles, Towers and Fixtures O&M ($/Pole)	$ 3.35	$ 4.67	$ 3.92	$ 4.26	$ 3.09	**$ 3.86**	**$ 11.65**	$ 2.14	$ 5.33	$ 5.09
Stations CAPEX ($/MVA)**	$ 2.82	$ 1,330.11	$ 409.99	$5,636.21	$16,215.09	**$4,718.84**	**$ 3,234.89**	$ 234.41	$30,439.20	$ 189.30
Poles, Towers and Fixtures CAPEX ($/Pole Addition)	$ 6,153.97	$ 9,301.20	$ 6,828.43	$6,982.19	$ 5,263.19	**$6,905.80**	**$24,157.88**	$23,246.73	$13,134.50	$7,084.91
Line Transformers CAPEX ($/Tranformer Addition)	$ 5,748.59	$ 4,350.29	$ 8,813.56	$6,277.61	$ 9,103.96	**$6,858.80**	**$16,976.24**	$11,192.05	$ 8,205.68	$9,304.32
Meter CAPEX ($/customer)	$ 3.64	$ 4.02	$ 24.92	$ 7.35	$ 2.35	**$ 8.46**	**$ 136.36**	$ 17.55	$ 10.72	$ 43.08

Billing cost per customer has been below industry average during the 2018-2022 period. Billing costs in the forecast years reflect increased staffing costs and billing allocations.

Metering O&M costs have been relatively stable over the historical period covered. During the forecast period, costs will increase with inflationary impacts, however the allocation of metering department time to the Smart Metering capital program beginning in 2025 will result in a reduction over 2023/2024. API's meter costs per customer may be higher than industry average due to the ongoing presence of hard-to-reach remote manually read meters. Staff must visit these meters in order to obtain meters. This is an unusual circumstance as most other Ontario distributors have eliminated manual meter reads following the implementation of smart and MIST metering. API is limited in its ability to do the same due to communication challenges with meters located in remote areas that make automated meter reading very difficult.

Vegetation Management costs per pole have been increasing over the historic period, and are expected to increase further in 2025. API has experienced inflationary impacts on the cost of completing vegetation management work, as well as increasing work volumes as a result of faster vegetation growth. These factors are further detailed in Exhibit 4.

API's vegetation management costs per pole are higher than the industry average. API's circumstances are significantly different than those of other Ontario distributors. For most distributors, vegetation management is required for service territories that cover a combination of urban and rural areas, with powerlines along roadways which may or may not have trees on one side of the power line (ie: with the roadway along the other side). Tree coverage may often be sparse for these distributors.

API's distribution lines are often located in remote areas, and do not always follow a road allowance. Heavy, very tall forestation is present for a significant component of API's lines, along both sides of the powerline. Furthermore, for off-road sections of the powerlines, the terrain may be difficult to access (ex: rocks, water crossing, etc). These factors, which are outside of API's control, result in significantly increased vegetation management cost requirements.

API also notes that the denominator for the Vegetation Management measure is cost per pole. As a remote distributor, API's poles are spread over a longer distance, with the 2022 industry average number of km of line per pole at 0.1, compared to API's 0.6 km per pole. The span between poles for API is 6-7x longer, therefore in addition to the increased tree density, propensity for double-sided tree coverage, and tree height, API must manage a greater number of trees per pole.

Lines O&M per km of line has fluctuated over the years, based on the focus of work activities and allocation of labour between capital and operating expenses. API's statistics have been lower than industry average, and are forecasted to become consistent with industry average in 2025.

Poles, Towers and Fixtures O&M have been relatively stable, at a level consistently less than $5/pole. The unit costs are significantly lower than the average for the industry.

Stations CAPEX per MVA is based on the stations additions in a given year. Since capital projects for stations can vary significantly from year to year, API does not consider this metric particularly meaningful. 2024 is expected to peak in 2024 due to the completion of the Bruce Mines DS project.

Poles, Towers and Fixtures CAPEX/pole addition has been relatively stable, fluctuating in the $5,300-$9,300 range. This category can be affected by materials cost, as well as the nature of the project work completed in a given year. Above-average cost per pole in 2023 reflect a specialized project which required establishment of new ROWs and other unusual work to complete. API's average cost per pole is significantly lower than industry average.

The cost per line transformer addition has also fluctuated in recent years. This can be attributable to the type of transformer installed, fluctuations in materials cost, and other factors. API's average cost per transformer is significantly lower than industry average.

Meter capital per customer fluctuates significantly depending on the type metering work completed in a given year. In low years, the distributor may only record the costs for incremental meters for new customers, resulting in a low cost per customer over the total customer base. High-cost years may reflect meter replacement projects occurring. In the historical period, API's meter capital per customer has been relatively low. An increase in 2020 is attributable to an increase in MIST meter implementation. Beginning in 2025, as a result of API's smart meter replacement program, the unit costs will increase compared to recent history. API's cost per meter are lower than industry average.

1.9.4 PERFORMANCE TARGETS/IMPROVEMENT

As outlined in the sections below, API has a strong history of meeting and exceeding performance metrics. API's customer satisfaction frequently exceeds the Ontario Average. API's reliability statistics during the most recent DSP cycle have consistently exceeded the target. Furthermore, despite increasing inflation and other challenges, API's total cost efficiency assessment over recent years has been trending downwards. API's safety results demonstrate consistent compliance and zero incidents.

API's goal for customer service metrics safety metrics will be to maintain the existing high level of performance. For Customer Satisfaction results, API continues to target above-average results, compared to the Ontario benchmark. For reliability metrics, API is committed to continuous improvement and has proposed capital and operating programs which will support this goal.

Likewise, API's target is to continuously improve its long-term total cost efficiency result, as assessed by Pacific Economics Group annually on behalf of the OEB.

1.10 FINANCIAL INFORMATION

The OEB's RRFE for electricity distributors includes Financial Performance as one of the performance measurements. The four-financial metrics included in API's Scorecard are liquidity, leverage, deemed return on equity and achieved a return on equity. API's metrics are discussed in Section 5 of the Business Plan. API has replicated the 2020 to 2023 historical year information below for ease of reference. The primary drivers of API's Achieved ROE in 2023 being greater than the Approved ROE is due to a combination of an increase in regulated income of $1.3M (distribution revenue increase of $2.2M, offset by OMA increase of $0.3M, amortization increase of $0.3M, property tax increase of $0.1M, income tax increase of $0.1M, and Other Income/Expense impact of $0.2M), and an increase in rate base of $9.0M.

Table 23– Financial Ratios from Scorecards

	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Leverage: Total Debt (includes short-term and long-term debt) to Equity	Profitability (Approved ROE)	Regulatory Return on Equity (Achieved ROE)
2020	0.77	1.30	8.52%	9.25%
2021	0.43	1.32	8.52%	9.38%
2022	0.26	1.44	8.52%	10.53%
2023*	0.20	1.39	8.52%	10.54%

**Scorecard for 2023 has not yet been published.*

1.10.1 HISTORICAL FINANCIAL STATEMENTS

The following attachments are included as Appendices.

- Attachment 1F Financial Statements, Year ended 31 December 2023
- Attachment 1G Financial Statements, Year ended 31 December 2022

1.10.2 ANNUAL REPORT

The Filing Requirements require an Applicant to file an "Annual Report and Management's Discussion and Analysis for the most recent year of the distributor and of the parent company, **as available and applicable**" [emphasis added].

Neither API, nor its parent company (FortisOntario) publish an Annual Report and MD&A.

1.10.3 PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

As of Application submission date, API is preparing a term sheet to support a planned third-party debt offering.

1.11 FACILITATING INNOVATION

1.11.1 INNOVATION

API has not identified any capacity-driven projects in the current DSP. However, when considering project alternatives to address operational constraints such as system capacity and performance during contingencies API will consider non-distribution system alternatives ("non-wires solutions") such as DER or demand response when developing possible solutions to relieve these types of issues. API is aware of the OEB's consultation regarding the development of a Benefit-Cost Analysis Framework for Addressing Electricity System Needs (EB-2023-0125) and will implement the OEB's requirements to the extent they are applicable to upcoming projects.

API has had very little opportunity to consider non-wire alternatives based on the configuration the API grid and the historical communication challenges associated with establishing an operational network. As API continues to invest in grid modernization and innovation, as described in section 5.3.1.6 of the DSP, API will be in a much better position to not only consider non-wire solutions but be able to implement non-wire solutions.

Several API capital programs are centered around modernizing API's distribution system and operation. Over the last 10 years, API has slowly been shifting towards a more modern grid; one that is more typical of other Ontario utilities. Do to the rural and remote nature of API's service territory, coupled with the lack of readily available or adequate communication infrastructure, the opportunity to build an operational network around SCADA and a central control room operation was historically not feasible or practical. The evolution and growth of the cellular network in recent years has given API the opportunity to build this network. In API's previous DSP, a SCADA implementation plan was commissioned, which was centered around the use of the Cellular network. In 2021, API commissioned a further study to evaluate the feasibility and performance of the cellular communication network throughout API's service territory. The results of this study are included in DSP Appendix G. Since then, API has proceeded with an initial phase of implementation and is planning to continue full implementation over this DSP period.

API's current operation relies on a developed OMS for outage response, outage planning and to manage its self-administered work protection. In 2021, API migrated the Sensus Meter data into our OMS. This has allowed Operations to view meter status reports in real-time (On, Off or No Response). API also gained to the ability in the OMS to send a ping echo request to verify whether power supply has been returned (this was previously managed through a webpage application separate from the OMS).

Through these improvements, API has improved the efficiency of outage response. The OMS has also enabled API to provide its customer-facing public outage map in 2024. API further plans to leverage this technology in 2024 in order to send interested customers a text message outage notification. As API continues further with these and other improvements over the DSP period, API expects to take advantage of further efficiencies.

As outlined above, API has also made innovative improvements in its customer service offerings, including making online forms available 24/7 for key customer account requests. API plans to investigate further customer service form automation in the future. In recent years, API has also improved its online portal, and promoted e-billing to customers. As required, API has made Green Button available to its customers and has enabled smart metered customers to select among various regulated pricing plans based on their usage patterns and preferences.

API is pursuing opportunities to apply innovative and environmentally friendly technologies in its operations. API's SSM Facility features incorporated environmental considerations such as energy-saving measures and water filling stations to enable a plastic bottle-free environment. The SSM facility features operational EV charging stations, and the facility was built to enable future on-site renewable generation. API has also taken steps in a pilot project investigating the potential for electrification of aspects of its fleet.

1.12 OTHER RELEVANT INFORMATION

1.12.1 DISTRIBUTOR CONSOLIDATION

API's most recent consolidation activity was the DLI MAADs transaction, which was approved by the OEB in Case No. EB-2018-0271 in April 2019. There is no rate harmonization requirement for this Application. In Exhibit 9, API has proposed to true-up a past DLI related disposition. Effective January 1, 2025 the previous rate riders applicable to former DLI customers will expire, as previously planned and committed.

API has not since undertaken any merger, acquisition or other consolidations.

API actively collaborates with other utilities in order to achieve more cost-efficient and productive customer outcomes, including with FortisOntario affiliates. Under the FortisOntario shared corporate services model, API and other affiliates (Canadian Niagara Power and Cornwall Electric) purchase the following shared services from Canadian Niagara Power:

- Billing
- IT Services including Billing/ERP System (SAP)[2]
- Finance and Accounting
- Legal
- Regulatory
- Executive and Governance
- Human Resources
- Health, Safety and Environment
- Engineering/Planning.

One of the benefits of this sharing mechanism is the provision of these services at lower costs than would normally available to API on a stand alone basis. For example, a stand alone utility may have a 2-FTE Regulatory Affairs department or a 3-FTE Executive team, however in FortisOntario these functions are shared among all affiliates, and the costs are allocated and shared accordingly.

A further benefit of this form of collaboration is the availability of more productive and powerful tools, as well as greater flexibility of resources. Through the use of the shared SAP system, API is able to access a more integrated and automated ERP/CIS system than would normally be affordable to a utility of 12,000 customers. API has access to in-house legal counsel and internal auditing functions, which would not normally be available to a utility of API's size. Implementation of policy initiatives and other one-time projects are completed with "internal" resources that are more knowledgeable about API and its customers, business practices and other specifics. API is able to complete these objectives through the use of a larger pool of available resources,

[2] SAP and related services are also shared with other LDCs.

mitigating timeline and cost risks. Examples of recent projects that have benefitted from collaboration include:

- Implementation of the Green Button Initiative;
- Completion of aspects of this Application (ex: Area Planning Study);
- Implementation of CyberSecurity policy and measures;
- Investigation and implementation of environmental initiatives.

In addition to the direct services provided listed above, FortisOntario LDCs collaborate frequently to share best practices, lessons learned, procedures, etc.

In addition to collaboration with affiliates, API also actively participates in industry groups, such as the Electricity Distributor Association(EDA) and Utility Standards Forum (USF). API has adopted many USF engineering standards. In addition to saving time and costs for the development of standalone engineering standards, this also allows API to achieve a greater level of consistency with other Ontario utilities, which can be beneficial in emergency response/mutual aid scenarios.

Lastly, API has benefitted from the purchase of services from specialized sector service providers, many of which are affiliates of other Ontario LDCs, which perform similar services for other LDCs. Through the use of these specialized firms, API is able to deliver services that are more cost-efficient and specially tailored to its customers. Examples of these services include:

- 24/7 outage call answering;
- Certain billing, bill print and bill presentment services;
- Green Button implementation;
- Services related to obtaining, processing and presenting interval meter data;
- MDRM Sync operations; and
- Utility business process consulting.

1.12.2 APPLICANT'S DISTRIBUTION LICENCE

API operates under OEB Electricity Distribution Licence ED-2009-0072. A copy of this licence is attached as Attachment 1H to this Exhibit.

1.13 IMPACTS OF COVID-19 PANDEMIC

1.13.1 IMPACTS OF COVID

The COVID-19 pandemic began in early 2020. For API, the impacts of the pandemic began with the declaration of a state of emergency by the Ontario government. Public health and other measures directly impacted API and its customers, communities and employees until most measures were lifted in March 2022. The global pandemic also caused wide-ranging economic impacts due to supply chain, and labour market impacts.

API was challenged to continue to supply safe and reliable power in the face of restrictions affecting its ability to operate. For example, due to physical distancing requirements, for much of the pandemic API staff were line staff were unable to travel in the same vehicle together, incurring greater travel costs. Increased hygiene and safety equipment was required. Certain in-person customer engagement activities were canceled, where it was not possible to hold these meetings online.

API also implemented changes to customer billing and collections practices in order to better assist customers with managing their bills during the pandemic. This included implementation of CEAP and CEAP-SB, implementation of temporary electricity pricing and temporary LEAP rule changes, and changes to API's collections practices.

Throughout this Application, where applicable, API makes reference to the impacts of the COVID-19 pandemic in the historic period. API's last COS application was applied-for and approved prior to the beginning of COVID-19 and therefore did not anticipate the impacts of the pandemic; notably the impacts to capital projects. As further discussed in Exhibit 2, the pandemic brought about timing and cost challenges for capital projects which necessitated departures from the timelines and budgets set in a pre-pandemic context. In Exhibit 2, API outlines the measures taken to limit the impact of these departures on key projects such as the SSM Facility and the Echo River TS project.

As outlined in Exhibit 9, API initially recorded amounts in account 1509 related to the impacts of COVID-19; however upon review of the OEB's guidance with respect to the disposition of this account, API determined it was unlikely to meet the eligibility criteria for disposition. API has previously confirmed its agreement to close the account without any disposition.

As outlined in Exhibits 2 and 4, API's capital and operating program costs have been affected by the inflationary, supply chain and labour market impacts of COVID-19. For capital projects in particular, the pandemic has caused timing and cost variances compared to the prior DSP.

Customer consumption patterns were also affected by the pandemic, as outlined in Exhibit 3. Many of the impacts were temporary in nature (for example the extent of residential increases during lockdowns), and are not expected to continue into the bridge and test years. API has adjusted its forecasting methodology to reflect this expectation.

ATTACHMENTS

Attachment 1A	Customer Summary
Attachment 1B	Business Plan
Attachment 1C	Executive Certification
Attachment 1D	Service Area Maps
Attachment 1E	Completed COS Checklist
Attachment 1F	2022 Audited Financial Statements
Attachment 1G	2023 Audited Financial Statements
Attachment 1H	API Distribution Licence
Attachment 1I	Customer Engagement Report
Attachment 1J	Project Responsiveness to Objectives

Attachment 1A

Customer Summary

Algoma Power Inc.
EB-2024-0007

ABOUT ALGOMA POWER

Algoma Power provides local distribution service to a rural area that extends approximately 93 km east and 255 km north of the City of Sault Ste. Marie. Algoma Power delivers electricity over 2,100 km of distribution lines to over 12,500 customers.

Algoma Power's low customer density (customers per km) results in higher than average costs per customer. As a result, rates for residential, commercial and industrial customers are subsidized (see "Rate Setting and Rate Relief").

ABOUT THE APPLICATION

Algoma Power applies to the OEB every year to approve rates for the following year. These applications are on a five-year cycle, with a detailed "Cost of Service" review in Year 1, followed by inflationary adjustments in Years 2-5. Much of the Cost of Service application relates to reviewing Algoma Power's costs and setting its base distribution rates.

Algoma Power does not own transmission lines or electricity generation plants, however it does include these costs on its bills, as well as the costs to operate the Ontario energy market (regulatory fees). Costs related to transmission and market operation are approved by the Ontario Energy Board (**OEB**). Some electricity generation costs are also approved by the OEB, while other costs are a product of either the competitive wholesale market, or long-term power purchase contracts. Algoma Power passes through these costs (generation, transmission and regulatory) without any markup or profit margin.

Since Algoma Power's revenue from these pass-through rates is typically different than its actual costs, rate applications include requests for "rate riders" that true-up any past differences. Depending on the year, these rate riders can either be charges or credits.

CUSTOMER ENGAGEMENT AND PERFORMANCE METRICS

Algoma Power has a broad customer and stakeholder engagement program that includes satisfaction surveys, meetings with First Nation and Municipal councils, forestry outreach programs, electrical contractor and road authority meetings, and participation in community-based events.

Algoma Power also conducted online customer surveys specific to this application, which provided an opportunity for customers to identify their needs and priorities, and to provide feedback on programs and spending levels. Over 10% of Algoma Power's customers responded to the survey, with a good response rate from various customer classifications.

Algoma Power has made proposals in its Application that are consistent with the feedback from all of the above activities with a goal of meeting the needs and preferences of our customers.

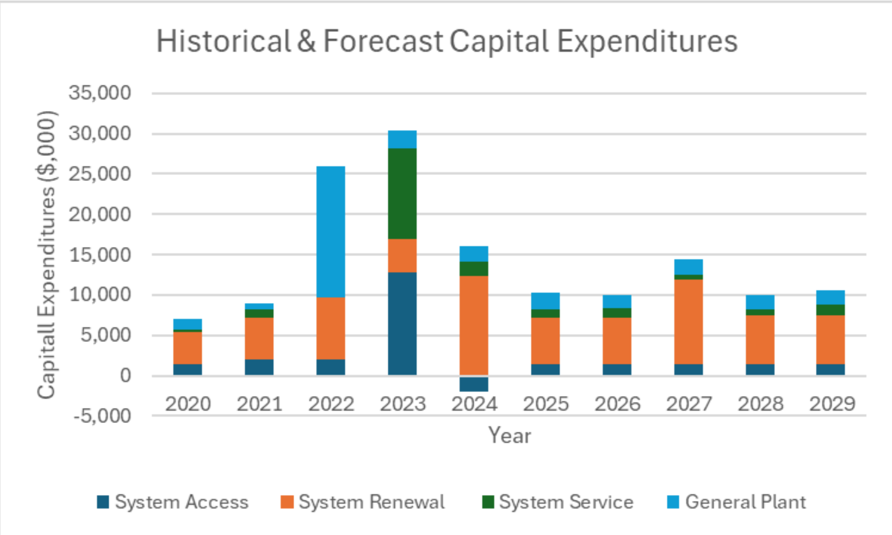
The OEB expects utilities to measure their performance across a number of categories: Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance. Every year, the OEB publishes a scorecard that compares Algoma Power's performance against targets and trends over the past five years, which can be accessed on Algoma Power's website. The following OEB website has additional information on utility performance: https://www.oeb.ca/utility-performance-and-monitoring

ALGOMA POWER'S GOALS

Algoma Power operates according to seven core values: Respect for People; Diversity, Equity and Inclusion; Safety and the Environment; Financial Success; Customer Service/Engagement; Productivity; and Community Involvement. Based on a combination of these values, customer preferences and OEB expectations (discussed above), Algoma Power identified six strategic objectives for its Five-Year Plan, which are discussed in Algoma's 2025 Business Plan (Appendix 1B of Exhibit 1 of the application).

SUMMARY OF ALGOMA POWER'S FIVE-YEAR PLAN

Algoma Power prepared a 2025-2029 Distribution System Plan that outlines its strategy and proposed spending levels for capital investments, and the ongoing operation and maintenance of its system. The following chart summarizes Algoma Power's actual (2020-2023) and planned capital investments (2024-2029):



OTHER PROPOSALS AND REQUESTS

The chart above shows a leveling out, and decrease in capital spending in 2025-2029, compared to the prior years which involved several one-time projects.

Algoma Power is also proposing to update its operating, maintenance and administrative (OM&A) expense funding to reflect updated post pandemic costs to operate and maintain a safe, reliable distribution system. Some of the key programs in the OM&A category are vegetation management, which is essential to avoiding tree-caused outages, and inflationary increases.

API has identified two sources of price volatility over the coming years: land use payments and certain types of benefit costs, and has proposed to true up these costs in the future (including providing customers a refund if cost levels are lower than anticipated).

For the Street Lighting and Seasonal customer classes, API has proposed rate-setting mechanisms to limit the annual total bill impact. For the seasonal class, this involves slowing down the transition to fixed distribution rates.

RATE SETTING AND RATE RELIEF

Algoma Power's forecasted 2025 costs of approximately $36 million includes operating costs, payments for capital investments that are spread over the life of the assets, the cost of debt and equity to support capital investments, and various taxes.

These total costs are divided between groups of customers (residential, commercial/industrial, seasonal and street lighting), and rates are calculated based on forecasted 2025 load and customer counts.

Revenue from seasonal and street lighting customers are projected to be lower than the costs assigned to them, requiring higher than inflationary rate increases for these customers from 2025-2029, however Algoma Power has proposed "bill mitigation" adjustment to phase-in the impact of the increases over time, reducing the impact in 2025.

Distribution rates for residential, commercial and industrial customers are subsidized by Rural and Remote Rate Protection (**RRRP)**. These customers pay significantly less than Algoma Power's calculated distribution rates. Rates for these customers are not tied to Algoma Power's costs, but instead are adjusted annually based on the average rate increase for all other Ontario distributors.

A number of other rate relief programs under the Fair Hydro Plan (lower time-of-use rates, caps on distribution rates for residential customers and credits for First Nation residential customers) are not affected by the application. API also works with Algoma District Services Administration Board to provide its Low-Income Energy Assistance Program.

Finally, annual adjustments to transition seasonal customers towards fixed monthly distribution would normally apply in 2025, however API has proposed to defer this adjustment.

BILL IMPACTS

For the distribution portion of the bill, API has forecasted a decrease of -$6.05 for a typical residential customer (750 kWh per month) and -$2.23 for a typical small commercial customer (2000 kWh per month). These adjustments are the result of the annual RRRP adjustment described above, and changes to rate riders. For a typical Seasonal customer using 200 kWh per month, the estimated distribution rate impact is $10.48, after applying reductions from the “bill mitigation” proposals outlined above.

Attachment 1B

Business Plan

Algoma Power Inc.
EB-2024-0007

2025 BUSINESS PLAN

Algoma Power Inc.

Table of Contents

1. Executive Summary

Algoma Power Inc. ("API") has developed this business plan to address the expectations of the OEB's *"Handbook for Utility Rate Applications"*, issued October 13, 2016. It outlines how the challenges associated with API's rural and rugged service area, API's core values and the preferences of API's customers have all been integrated into its cost of service application (the "Application") and Distribution System Plan ("DSP") in a manner that is consistent with the outcomes of the OEB's Renewed Regulatory Framework ("RRF"). This business plan also summarizes API's historical, target and forecasted performance with respect to performance metrics to ensure that API delivers on its strategic objectives.

API has established core values that are integrated into its planning process and daily activities, as well as objectives and principles that are integral to its asset management process. Section 2 of this document outlines these values and principles, and summarizes how they are aligned with the objectives of the RRF. Based on these values and principles, as well as the identified preferences of API's customers, strategic objectives are identified that drive projects and programs in the 2025-2029 period.

An overview of API and its ownership structure, service area, unique aspects and key challenges is provided in Section 3 of this business plan.

Section 4 focuses on the four categories of RRF outcomes, and discusses how these have informed the Application and DSP, with a particular focus on customer engagement ("CE") activities specific to the application and the customer preferences identified through those activities.

Section 5 of this document summarizes performance metrics that have been considered during the planning process and that will be used to ensure that API delivers on its plans.

2. Guiding Principles and Strategic Objectives

2.1. Values and Principles

Algoma Power Inc. has established seven core values that all employees should strive to promote and comply with each working day. To be effective, these values must be understood, communicated, reinforced and integrated into all our daily activities. Algoma Power's six core values are the following:

- **Respect for People:** Treat others as you would have others treat you. Honesty, integrity and ethics are never compromised.
- **Diversity, Equity and Inclusion:** Create a welcoming environment that encourages and promotes diversity, cross-culture working experiences and strong relationships with our Indigenous communities and partners. Demonstrate leadership and foster a workplace culture where all employees feel empowered to bring their authentic selves to the workplace, and do their best work.
- **Safety and the Environment:** Demonstrate a personal, unrelenting commitment to safety and environmental excellence. Protect yourself, your fellow employees, the public, and the environment.
- **Financial Success:** Produce solid earnings, with dividends that meet the expectations of our shareholders. Grow shareholder value through prudent equity investments and business partnerships. Ensure that debt obligations are always met in a timely manner and to the satisfaction of our creditors.
- **Customer Service:** Everyone has customers. Determine customer needs by listening. When you can meet these needs, do so; when you cannot, tell them you cannot – or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers be pleasant, courteous and accurate; smile, act professionally and enjoy yourself…attitudes are contagious.
- **Productivity:** The old sayings hold true. Teamwork is key. Working smarter produces more gains than working harder. Mistakes are costly; get it right the first time. Job security comes from doing your job well, not from what job you do. Remember…if you have a better way to do something; just do it.
- **Community Involvement:** Each of us has an obligation to support the communities that support our employer. This means time as much as money. Success is measured by the reaction of community leaders and the opinions expressed by community residents.

In addition to the core values above, the fundamental objective of the API Asset Management Program ("AMP") is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing both short and long term costs. This objective is met through the application of thorough and sound planning, prudent and justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans.

API maintains a comprehensive AMP which outlines operating and capital processes, activities, and expenditures to ensure that API continues to provide safe, reliable, and efficient distribution of electricity to its customers. There are three key principles that are integral to API's asset management process:

- Meet the needs and expectations of its customers, as identified through regular customer engagement;
- Provide safe, reliable, and high quality service to all of the customers of API; and
- Satisfy the first two principles in a sustainable manner which minimizes the long-term costs to be borne by the ratepayers of API.

Finally, API is guided by the four categories of outcomes under the OEB's RRF, namely customer focus, operational effectiveness, public policy responsiveness, and financial performance. Additional information on how each of the RRF outcomes has influenced the Application and DSP is provided in Section 4.

The table below summarizes the relationship between API's core values, its asset management objectives and principles, and the RRF performance outcomes established by the OEB.

Table 1 – Values and Principles by RRF Outcome

RRF Performance Outcome	API Asset Management Objectives/Principles	API Core Values
Customer Focus	Meet the needs and expectations of its customers, as identified through regular customer engagement; Provide safe, reliable, and high-quality service; Minimize long-term costs to be borne by ratepayers;	Customer Service Respect for People Community Involvement Safety and the Environment Diversity, Equity and Inclusion
Operational Effectiveness	*Prudently and efficiently* manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner	Customer Service Productivity Diversity, Equity, and Inclusion
Public Policy Responsiveness	Principles are derived from safety considerations; *acts, regulations, codes and guidelines*	Safety and the Environment
Financial Performance	Prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement *of all distribution assets in a sustainable manner*	Productivity Financial Success Diversity, Equity and Inclusion

2.2. Strategic Objectives

Based on the values and principles identified in Section 2.1, and the preferences of API's customers as identified through customer engagement, the following objectives are the primary driver of projects and programs identified in the 2025-2029 DSP:

- Sustaining End of Life Asset Replacement
- Sustaining Vegetation Management
- Worker and Public Safety, Environmental Protection, Cybersecurity
- Reliability Improvement – Focus on Reducing Outage Duration
- General Plant Investments to Support Productivity and Efficiency
- Flexible Approach to Emerging Technology and Public Policy

Section 4.7 summarizes how each of the above objectives relates to RRF outcomes, API core values and/or customer-identified preferences.

2.3. Strategic Initiatives

The following projects and programs in the 2025-2029 DSP are planned in consideration of meeting the objectives identified above:

Worker and Public Safety, Environmental Protection, Cybersecurity

All System Renewal projects and programs have inherent benefits with respect to worker and public safety and protection of the environment. By proactively replacing end of life assets on a planned basis, API can ensure that work is executed in a controlled manner, using work methods that provide the highest degree of project safety planning to protect its workers and the public. Further, API can plan the timing of this work to reduce impacts to species at risk and significant natural areas, and can consider alternative work methods or site access options as required. In contrast, reacting to sudden failures during outage and emergency situations often results in work being performed in unfavourable working conditions and with limited consideration of alternative access or work methods.

Cybersecurity protocols are taken into account where applicable, and programs such as the smart meter replacement and distribution automation will apply cybersecurity best practices.

Sustaining End of Life Asset Replacement

Proactive asset replacement allows for the replacement of older, at end-of-life assets, prior to failure. The result is a balance between the cost of the asset replacement and relatively larger costs, reliability impacts, and safety concerns associated with reactive replacement of these assets. The proactive approach also affords more efficient mobilization of material, equipment, and crews as well as provides the least impact on reliability and improves infrastructure resiliency.

Visual inspection and other forms of testing are performed on the infrastructure according to API standards. API has continued all of its System Renewal Programs from the 2020-2024 DSP. Forecasted costs for the Line Rebuild and Express Feeder Rebuild programs are based on target replacement rates and historical unit costs. Forecasted costs for the Small Lines/Stations program, which replaces lower-value assets that have failed or have been identified as a high risk of failure, are based on a five-year historical average.

Sustaining Vegetation Management Program

The intent of the vegetation maintenance program is to manage a variety of vegetation control and removal activities within the expanded ROWs on cycles that sustain clearances, address safety and reliability risk and are financially sustainable in the long term. API's Vegetation Management Program (VMP) supports API's completion of other key capital and operating programs.

Given the level of tree coverage, often on both sides of API's distribution lines, vegetation related outages are expected to continue to be the highest contributor to API's outage statistics. The VMP has been effective at reducing outage frequency and duration over recent history.

API has experienced upward pressure on vegetation management costs, due in part to inflationary impacts and in part to increased volumes of required work caused by accelerated tree growth and other factors. API plans to pursue increased efficiencies through extending the use of and/or introducing new work practices such as more mechanized equipment and different herbicide applications.

Reliability and Resilience Improvements

API reviews reliability statistics monthly to identify areas of poor distribution system performance. This process indicates any trends in poor performance and identifies opportunities to improve reliability. API also completes ACAs to identify assets that present a risk of impacting system reliability. API uses reliability indicators and ACA data as key drivers in the system planning process.

As outlined above, the extent of forestation in API's service territory means that tree contact outages are likely to remain the greatest cause of outages, however API has made significant improvements in its tree related outage performance over recent history. Appropriate vegetation management supports reliability and resilience improvements not only through avoiding outages that would otherwise occur, but also through enabling crews to efficiently respond to outages when they occur, minimizing outage duration. Investments in ROW/Land Use and ROW Access further support these reliability and resiliency improvements.

Additionally, API has completed Reliability and Area Planning Studies which highlight opportunities for reliability and resiliency improvements. The Protection, Automation and Reliability Program is a multi-year program which includes programs targeted at reliability improvement. These programs include distribution automation, improved system contingency/redundancy, and voltage reinforcement.

API's planned System Renewal investments also naturally support reliability and resiliency goals, as new equipment reduces the risk of unplanned asset failures. Additionally, replacement equipment, which is built to API's current standards, is often better able to withstand severe weather and other reliability/resiliency threats.

Over the forecast period API will invest in converting and upgrading portions of the API's distribution feeders in the Goulais region and upgrade and support API's distribution connection at Goulais TS as part of the HOSSM's refurbishment project. Installation of additional protection and control equipment and distribution automation schemes to improve reliability and outage response.

General Plant Investments to Support Productivity and Efficiency

To help with efficiency in the daily operations, API is working on developing and constructing new access routes to its infrastructure for quicker access to maintain or restore infrastructure. In addition the SCADA program is continued to be implemented to allow for the collection of system data that wasn't available previously.

The advancement in SCADA and communications has enabled API to invest in innovative technologies such as automatic fault location detection and system isolation and restoration. Ongoing, sustaining replacement of API's fleet and vehicles ensures API is able to respond to issues promptly when required, and that API is able to complete its planned operating, maintenance and capital programs.

Several programs in other investment categories also have safety and environmental benefits. For example, the ROW Access program will establish more permanent access to certain remote sections of

API's system, reducing exposure to hazards and the potential for environmental impact otherwise associated with emergency access. Further, new fleet purchases are typically safer and more fuel-efficient than the fleet equipment being replaced.

A Cost-Effective Long Term Approach to Energy Transition

API has considered long term growth in its Area Planning Study, including scenario analysis modeling increases related to Electric Vehicle charging and other forms of electrification. Certain DSP projects over the 2025-2029 period take long-term load growth and/or enablement of DERs into consideration, including: the Wawa #2 DS, the Goulais TS Refurbishment and Voltage Conversion, and the Protection, Automation and Reliability Program.

Certain reliability and SCADA investments in the System Service and General Plant categories will provide a foundation for future requests to connect DERs or for API to employ DERs as a Non-Wires Solution.

API's DSP does includes a commitment to consider the use of DERs as a non-wires solutions, consistent with the OEB's Benefit Cost Analysis framework. API expects that emerging technologies will continue to mature and that public policy direction will continue to evolve over the forecast period and will incorporate consideration of emerging technologies into its planning process and its evaluation of alternatives as appropriate.

3. Utility Overview

3.1. Overview of the Service Area

Location and Geography

API's service area extends approximately 93 km east and 255 km north of the City of Sault Ste. Marie, covering approximately 14,200 km^2, which includes 7 First Nation Reserves, 14 organized townships, and a large number of unorganized townships. This vast service area is located in the Canadian Shield; a rugged and unyielding expanse of bare rock, lakes, muskeg, and trees. It also spans two different forest zones (the Great Lakes – St. Lawrence forest zone and the Boreal forest zone), with the result that the majority of API's distribution lines, 99% of which are overhead, are constructed through areas of dense vegetation.

Employment and Industry

Employment in API's service area has historically been driven by the natural resource, agricultural and tourism sectors. Development and maintenance of hydroelectric generation facilities has also been a large part of the economy, particularly in the Wawa to Montreal River area. Private and public sector service industries supporting these industries and local populations have also been large employers.

Approximately two thirds of API's customers are residential. Among these customers is a mix of customers employed by organizations in API's service area, and customers residing in API's service area but commuting to other municipalities for work, mostly in the City of Sault Ste. Marie. An aging population also means that API's residential class includes a large base of retirees. As of the 2021 census, the median age in the Algoma District was 50.0 years, compared to 41.6 years for Ontario as a whole. Commercial and Industrial customers currently comprise less than one-tenth of API's total customer base, with only 0.4% of all accounts having a demand greater than 50 kW.

The rugged wilderness, rural and remote nature, and recreational opportunities associated with API's service area attracts a relatively large seasonal population, with about one-fifth of API's customer accounts classified as Seasonal. The proportion of seasonal customers has decreased over time as a result of customers converting from Seasonal to Residential accounts.

Climate

The climate in API's service area is humid continental, which is characterized by large variations in seasonal temperatures including cold winters and warm, humid summers. Due to the size of its service area, temperatures and weather conditions are often quite varied between the northern and southern limits of its service area. The annual average temperature ranges from 2.1°C in Wawa to 4.7°C in Sault Ste. Marie. Daily average temperatures in Wawa and Sault Ste. Marie fluctuate from a low of approximately −10°C to −14°C in January to a high of approximately 15°C to 18°C in July and August. Weather extremes are more pronounced, with Wawa experiencing extreme minimum temperatures as cold as −50°C and Sault Ste. Marie experiencing extreme maximums of 36.8°C.

The entire API service territory is located on the leeward shore of Lake Superior. As a result, the region is prone to lake effect precipitation which occasionally limits API's ability to access portions of its service territory. In recent years, API has seen a number of severe storms, with significant precipitation, and winds approaching, and in some cases exceeding, current design standards. While API's distribution assets have generally withstood these weather conditions, the winds and associated precipitation have caused a large number of tree-related outages during major event days.

3.2. Utility Ownership

API is a wholly-owned subsidiary of FortisOntario Inc. ("FortisOntario"), which is headquartered in Fort Erie, Ontario. FortisOntario also owns Canadian Niagara Power Inc. (licensed transmitter and distributor), Cornwall Street Railway Light and Power Company Limited (licensed distributor), and a 5 MW natural gas cogeneration district heating plant located in Cornwall, Ontario (licensed generator). FortisOntario is the Ontario-based subsidiary of Fortis Inc. ("Fortis"), which is the largest investor-owned gas and electric distribution utility in Canada. FortisOntario subsidiary Wataynikaneyap Power PM Inc. acts as project manager for the Wataynikaneyap Power transmission project in Northwestern Ontario. FortisOntario holds a ten percent interest in each of three other licensed distributors: Westario Power Inc., Rideau St. Lawrence Holdings Inc., and Grimsby Power Inc.

Fortis is a publicly traded company listed on the TSX and the NYSE, with assets throughout North America including the Caribbean.

3.3. Acquisition of Dubreuil Lumber Inc.

All elements of this business plan reflect a full integration of DLI's distribution system and customers, effective January 1, 2020.

3.4. Utility Description

API owns and operates the electricity distribution system in the district of Algoma, serving approximately 12,500 customers on a distribution system consisting of 2,100 kilometers of distribution line. Due to cold winters, a high penetration of electric heating, and a relatively low penetration of central air conditioning, API's distribution system is winter-peaking.

API's vast service area and low customer density have resulted in a distribution system topology that is unique as compared to the majority of Ontario LDCs. API's distribution system is comprised of several distribution regions, operating independent of each other, that are either interconnected by API's own express feeders are generally independently supplied through distinct transmission supply points. The large number of transmission supply points and the use of express feeders to supply vast areas in a transmission-like manner results in limited load transfer capability between API's various distribution regions. It also results in a disproportionate amount of customers and load being supplied by a small number of express feeders that are often located in remote areas with challenging terrain.

3.5. Rate Subsidies

As a result of regulations made under the *OEB Act*, distribution rates for all of API's residential, commercial and industrial customers are subject to Rural and Remote Rate Protection ("RRRP"). Under the RRRP framework for API, distribution rates are adjusted annually based on the average distribution rate increase for all other electricity distributors in Ontario. During a cost of service year, a RRRP funding amount payable to API is calculated as the shortfall between the portion of API's revenue requirement allocated to the RRRP-eligible classes, and the forecasted revenue to be received from those classes at RRRP-subsidized rates. During subsequent IRM years, rate-setting for these classes and recalculation of the RRRP funding amount considers both the RRRP inflationary adjustments to rates and the price-cap IR factor that would otherwise be applicable to API.

Additional regulations made under the *OEB Act*, introduced concurrently with the Fair Hydro Plan, further reduce amounts payable by residential customers. The Distribution Rate Protection ("DRP") program limits the base monthly distribution charge for residential customers of 8 electricity distributors, including API, to the equivalent fixed rate for the lowest-cost of the 8 distributors. Further, for residential on-reserve customers, the First Nations Delivery Credit ("FNDC") program results in on-bill credits that offset the entire delivery line of the bill, which includes rate riders, pass-through transmission rates, and the cost of system losses.

3.6. Unique Features

The following unique requirements resulting from API's vast and heavily-forested service area, as described above, have been factored into the strategic objectives and strategic initiatives identified in Section 2 of this Business Plan:

- **Vegetation Management:** API must continue to manage vegetation along its rights of way in a sustainable manner, with consideration of safety, cost, reliability, and access. The extent of API's vegetation management requirements exceed those of most Ontario Distributors, given the level and type of forestation in API's service territory as well as the proportion of API's distribution system which is located off-road and crosses forested land, with dense vegetation growing on both sides of the Right of Way.
- **Low Customer Density:** API's vast service area and low customer density means that more assets such as substations, distribution lines, and transformers are required to serve a typical customer as compared to other distributors. Despite having three service centres, API's crews must generally travel long distances to access distribution assets or customer premises for various distribution activities. API must balance meeting the needs and expectations of its residential and general service customers (whose rates are decoupled from API's costs as a result of RRRP and DRP subsidies), and its seasonal and street lighting customers (whose rates remain directly tied to API's costs).
- **Limited Localized Distribution:** Related to its low customer density, the topology of API's distribution system results in extensive use of express feeders and long radial lines, limited clustering of customers, and little interconnection between distribution regions. API must therefore focus on the reliability of its transmission supply points, express feeders, and substations, particularly with respect to contingency planning for equipment failure to mitigate the risk of prolonged system outages.
- **Land Related Issues:** API must ensure that the impact of planned investments and planned maintenance activities respects the variety of land rights and other rights held by First Nations, Municipalities, Crown agencies, and private landowners. Further, API's work activities for any given project or activity must consider a variety of legislation related to protection of the environment and significant natural areas.
- **General Access Issues:** Sections of API's distribution system are not accessible by public roads and rights of way. API must therefore continue to establish and maintain formal access agreements with property owners and land rights holders, and must also maintain suitable off-road equipment to access various portions of its distribution across challenging terrain. In some cases, API must also establish and maintain access trails and appropriate landing or docking sites for aircraft and watercraft.
- **System Reliability :** All of the requirements listed above impact API's ability to either prevent outages, minimize the customer impact of an outage, or effectively restore its system to a normal operating condition. In making choices related to spending on different projects and

programs, API must assess trade-offs between maintaining historical reliability levels, implementing technologies to improve reliability, and reducing the risk of prolonged widespread outages during system contingencies.

Each of the above items is addressed in further detail in API's DSP.

4. Outcomes of the Renewed Regulatory Framework

On October 18, 2012, the OEB issued its "*Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*." The report set out a comprehensive performance-based approach for the Renewed Regulatory Framework ("RRF") which is an evolution to an outcomes-based approach, in consideration of four key categories:

- Customer Focus
- Operational Effectiveness
- Public Policy Responsiveness
- Financial Performance

This section describes how API continues to improve in understanding the needs and expectations of its customers, and how API's core values, the needs of its customers, and the RRF outcomes are integrated and prioritized in its planning activities.

4.1. Customer Focus

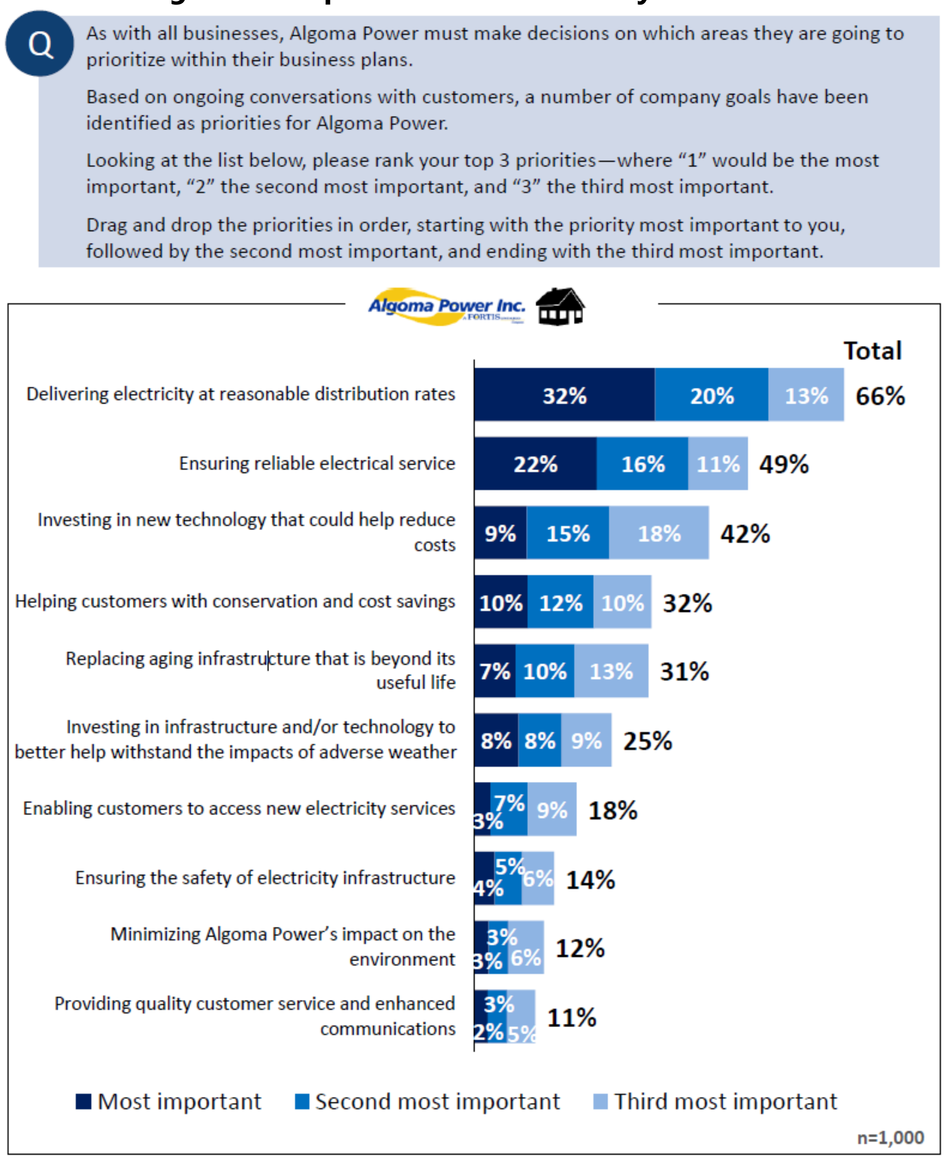
Customer and stakeholder education and engagement has long been a central component of API's planning process. Given the expansiveness of its service area and the variety of customers and other stakeholders, API employs a variety of education and engagement approaches that includes customer satisfaction surveys, community outreach/stakeholder sessions, forestry outreach, and other supporting engagement activities. API strives to continuously enhance its engagement activities, as well as to seek feedback to understand which engagement and communication channels are considered to be the most effective by its customers. API has implemented a formal approach to education and engagement with respect to its cost of service and distribution system planning process, as described in Section 4.2.

4.2. Identification of Customer Needs and Preferences

API conducted the 2025 customer engagement Online Workbook Report via email ahead of the 2025 COS application to gauge the customer preferences on program expenditures. The focus of this survey was to educate customers on API, its role in the distribution system, and solicit feedback on customer preferences and API's COS proposals.

In table 2 below is the results of the indication of three most important priorities that Algoma Power should prioritize. The outcome was that customers want electricity delivered at reasonable distribution rates, ensuring reliable electrical services and investing in new technology that could help reduce costs.

Figure 1 – Top 3 Priorities Ranked by Customers



API surveyed customers from different classes on possible approaches to eight different distribution projects. For each project, customers were presented with possible approaches, as well as their expected service and cost impacts.

For pole replacement the survey indicated the majority would like the organization to continue replacing 500 poles a year. For substation capacity increase, the majority indicated they would like a 50% capacity increase in the future transformers procured. With respect to a voltage conversion program, most customers supported an upgrade and voltage conversion of 50%.

Compared to the other categories, the survey results regarding proactive transformer replacement to prepare for electrification were most varied among the rate classes, with the residential class wanting the proactive replacement of 275 transformers by 2029 whereas seasonal, small business and large business data showed a preference to keep the status quo of approximately 12 transformers a year when they fail. For the overall sample, the customer base preferred the "status quo". The survey displayed customer preference for full implementation of the automated "intelligent" switches to help restore power remotely. For vegetation management, the rate classes supported API's historical approach to hazard tree removal, versus the option to increase or decrease the cycles. Overall the sample expressed the overall plan should be spent according to its current draft plan. API's proposals are consistent with the customer preferences expressed in the survey.

Table 2 - Results of Customer Engagement Survey

	Residential [n=1,000]	Seasonal [n=350]	Small Business [n=35]	Large Business [n=7]
Pole Line Replacement				
Accelerated Pace	24%	20%	9	1
Current Approach	62%	60%	22	5
Slower Pace	14%	19%	4	1
Substation Rebuild				
Like-for-like capacity	15%	21%	5	2
50% capacity increase	47%	58%	19	5
100% capacity increase	38%	21%	11	0
Voltage Conversion				
Minimum level	13%	21%	2	2
Mid Level	54%	54%	27	5
Full level	33%	25%	6	0
Preparing for Increased Electricity Demand				
Status Quo	38%	55%	18	5
25% Proactive Replacement	44%	30%	13	2
50% Proactive Replacement	18%	16%	4	0
Automated "Intelligent" Switches				
Status Quo	17%	24%	5	1
Partial Implementation	27%	32%	15	2
Full Implementation	56%	43%	15	4
Vegetation Management				
Reduced cycle approach	13%	15%	4	1
Standard cycle approach	67%	67%	22	5
Increased cycle approach	21%	19%	9	1
Overall Plan Evaluation				
Spend more	33%	21%	10	1
Spend according to draft plan	52%	52%	19	5
Spend less	5%	17%	5	1

The top three priorities identify by the customer base in the CE Workbook are;

1. Delivering Electricity at a reasonable distribution rates
2. Ensuring reliable electrical service
3. Investing in new technology that could help reduce costs

Table 3 -Customer Identified Priorities

Priorities	Residential [n=1,000]	Seasonal [n=350]	Small Business [n=35]	Large Business [n=7]
Deliverying Electricity at reasonable distribution rates	66%	79%	26	5
Enabling customers to access new electricty services	18%	18%	8	0
Ensuring Reliable Electrical Service	49%	48%	11	3
Ensuring the safety of electricity infrastructure	14%	13%	7	4
Helping customers with conversation and cost savings	32%	26%	10	1
Investing in infrastructure and/or technology to better help withstand the impacts of adverse weather	25%	20%	8	0
Investing in new technology that could help reduce costs	42%	49%	12	2
Minimizing Algoma Power's impact on the environment	12%	8%	5	1
Providing quality customer service and enhanced communications	11%	11%	4	3
Replacing again infrastructure that is beyond its useful life	31%	28%	14	2

Therefore, the DSP emphasis the concerns of the customers by addressing the following as major drivers for the projects planned;

- Non-discretionary investments driven by customer connection requests and third-party requirements (System Access)
- Asset end-of-life considerations, based on the results of its ACA, its asset management objectives, and the outcome of area planning studies (System Renewal)
- Investments to improve system reliability and reduce contingency risk based on the outcome of the area planning study, reliability study, planning report, and aligned where practical with end-of-life considerations (System Service)
- Investments to support operational efficiency and day-to-day operation, maintenance, customer service and administrative functions (General Plant)

Emphasizing these areas will aid in achieving the anticipated sources of cost savings and reliability the customers are looking for.

4.3. Operational Effectiveness

With respect to the RRF outcome of operational effectiveness, distributors are expected to achieve continuous improvement in productivity and cost performance, while delivering on reliability and quality objectives.

API's cost performance, according to the OEB PEG Benchmarking model, shows an improving trend over the ten-year period comprising the ten year period from 2016-2025 (considering the forecasted assessments for 2023-2025). At the same time, API's scorecard shows consistent safety performance and improving system reliability over the most recent five-year period. These metrics are discussed in additional detail in Section 5.

4.4. Public Policy Responsiveness

Distributors are expected to deliver on obligations mandated by government. Historically, API has reported the connection of renewable generators and achievement of conservation and demand projects on its Scorecard, however these programs have changed in recent years due to changes in public policy.

API continues to connect renewable generators on a timely basis, however now these generators are typically connected through a net metering process. API has updated its processes to support the connection of Electric Vehicle charging and DERs in accordance with OEB requirements.

API continues to monitor the OEB's (and/or Government) policy progress with respect to connection of DERs, preparing for the Energy Transition, Climate Change and Distribution Resilience, and the use of Non-Wires Solutions.

4.5. Financial Performance

Under the RRF, distributors are expected to achieve improvements in efficiency that are sustainable, while maintaining financial viability and earning a fair return. Historical financial results are discussed in Section 5.7 of this Business Plan.

4.6. RRF Impact on DSP

Table 4 – DSP RRF Performance Outcomes

	Customer Focus	Operational Effectiveness	Public Policy Responsiveness	Financial Performance
Sustaining End of Life Asset Replacement	✓	✓	✓	✓
Sustaining Vegetation Management	✓	✓	✓	✓
Worker and Public Safety and Environmental Protection and Cybersecurity	✓	✓	✓	
Reliability and Resiliency Improvements	✓	✓	✓	✓
General Plant Investments to Support Productivity and Efficiency	✓	✓	✓	✓
A Cost-Effective, long term approach to energy transition	✓	✓	✓	✓

As described in Section 2.1, there is significant alignment between the OEB's RRF outcomes, API's asset management principles and objectives, and API's core values. Results of the Taking AIM customer engagement survey also indicate that following its core values during the planning process will help ensure decisions made result in value to customers. With this in mind, API identified the following Strategic Objectives for its 2020-2024 DSP:

Sustaining End of Life Asset Replacement

Replacement of end of life assets on a level and sustaining basis, in accordance with API's end of life replacement strategy for each asset type was a key component of the 2020-2024 DSP, and remains a focus for the 2025-2029 DSP. This strategy is aligned with API's asset management objectives, as well as the OEB's goals in the RRF. This aspect of API's strategy is aligned with customers' top priorities of cost effectiveness and reliability. API approaches its System Renewal with the goal of optimizing asset life cycles, avoiding costly reactive repairs, and minimizing early write-offs. The replacement of aged and deteriorated assets also promotes reliability by mitigating the risk of asset failure outages. Further, a majority of API's customers support API's existing status quo pole and line replacement. API continues to improve in its collection, reporting and analysis of condition based data, undertaking a formal asset condition assessment and a number of other third-party studies that support the System Renewal investments in its 2025-2029 DSP.

Sustaining Vegetation Management

API's vegetation management program (VMP) also aligns with the RRF objectives of operational effectiveness and financial performances, as the VMP is designed to minimize costs by optimizing vegetation clearing and brush control cycles. The VMP supports public policy objectives, particularly by supporting resilience through reducing resiliency event risks, as well as supporting API's preparedness to respond in the event of a resilience event. The VMP further supports customers preferences by improving outage performance. API's VMP is designed to minimize costs, consistent with customers' focus on cost control.

In addition to reflecting the general customer preferences of reliability improvements and cost control, API also demonstrates a customer focus in its VMP through its educational engagements in support of its VM activities. API specifically surveyed its customers regarding its hazard tree program. Customers supported API's status quo approach, compared to opportunities to increase or decrease the cycles for this program. Customers also indicated that reducing tree-caused outages is a high priority (third ranked priority as it relates to reliability).

Worker and Public Safety, Environmental Protection and Cybersecurity

As a core value, API expects a commitment to safety and environmental excellence to be integrated into all of its activities, including its distribution system planning processes. Safety related metrics are a key component of the OEB scorecard as it relates to operational effectiveness. The majority of projects and programs in the DSP have primary drivers other than safety or the environment; however, consideration of safety and environmental protection must remain an area of focus in the prioritization and scoping of projects, as well as in the identification of work methods and timing for project execution. Sustaining investments in fleet, tools and ROW access in the General plant category must ensure that workers have the necessary tools, equipment and access required to perform their jobs safely. API maintains a robust cybersecurity program, which is in line with public policy, and demonstrates API's focus on customers, by taking measures to protect continuity of customer service and protect customer privacy. Cybersecurity programs are designed with operational effectiveness in mind, providing protection to API's essential IT and OT resources.

Through the use of shared FortisOntario resources, API's Health, Safety and Environment and Cybersecurity programs are completed in a cost-effective manner, supporting the RRF objectives of financial performances and operational effectiveness.

Reliability and Resiliency Improvements

Reliability of power supply continues to be among the top priorities for API's customers, and API's plans for the 2025-2029 period are in alignment with this priority. In addition to the reliability benefits of the programs mentioned above (sustaining asset programs and vegetation management), API has proposed reliability-focused investments as part of its Protection, Automation and Reliability program.

The program demonstrates operational effectiveness and supports financial performance by targeting investments to areas and technologies which present the greatest opportunities for reliability improvements. API's programs also support the recent public policy focus on resilience of the distribution system. API's proposed reliability improvements also support the avoidance and preparation for resilience events. Furthermore, some of the Automation-focused projects in this program support future integration of DERs.

API's customers supported the proposed approach for implementation of automated switches, compared to the lower-cost options to maintain the status quo, or partial implementation.

General Plant Investments to Support Productivity and Efficiency

General Plant investments include investments in API's fleet and facilities, in its ROWs and ROW access, and in IT software and hardware. These investments support API's ability to complete its other programs and projects in an efficient way. Sustainable fleet investments, for example, support API's ability to complete capital projects and to respond to customer requests and outages. Investments in IT assets support improved service offerings to customers such as online customer service options, as well as enhanced outage communication. These investments can also support outage response and help API prepare for future resilience events. Continued investments in SCADA, will also support API in the connection of DERs and other technological and electrification initiatives.

A Cost-Effective, long term approach to energy transition

In its DSP, API has therefore reflected a commitment to consider the use of DERs as a non-wires alternative to traditional investments on a case-by-case basis, but expects to do so with a focus on cost-benefit to its customers, and consideration of the risks associated with emerging technologies, as opposed to opportunities to pilot new technology.

In its DSP, API has investigated various load growth scenarios in its Area Planning Study to plan to avoid long term capacity constraints. API has proposed, and customer feedback has supported, API's plan to incrementally upgrade capacity of some assets in conjunction with condition-based replacement work, which represents a long-term cost-effective solution for preparing for future growth.

API's proposed approach is aligned with customer preferences, which indicate some uncertainty regarding the need to prepare in advance for increased electricity demand (ie: as indicated by the response to a proactive transformer replacement program).

5. Performance Metrics and Targets

On March 5, 2014, the OEB issued its *"Report of the Board – Performance Measurement for Electricity Distributors: A Scorecard Approach"*. The resulting OEB Scorecard contains a set of performance measures and standards to assess distributor performance against the four categories of RRF outcomes identified in Section 4.

This section discusses API's performance in relation to each of the OEB Scorecard performance measures over the last five years. Targets for future performance are also discussed, with an emphasis on specific performance measures identified as important to customers and performance measures that have significantly influenced the development of API's 2025-2029 DSP.

Prior to discussing individual OEB Scorecard performance measures, additional context is provided in relation to the OEB's LDC benchmarking efforts in consideration of API's circumstances, as well as API's capital investment plans and operational costs that underpin a number of cost control metrics and financial ratios presented later in this section.

5.1. OEB Benchmarking

As a rural, remote and low-density LDC, API has historically struggled with interpreting the results of the OEB's OM&A and total cost approaches to benchmarking in a meaningful way. As early as the April 2007 PEG report there was a recognition of the challenges associated with benchmarking API (Great Lakes Power at the time), and acknowledgement that models other than those ultimately adopted by the OEB may be more appropriate for benchmarking API on a total cost basis:

> *For example, the translog model may do a better job of recognizing the special cost challenges faced by a company that, like Great Lakes Power, has extremely low customer density.*[1]

In the same report, in determining appropriate peer groups for comparison of results, OEB Staff moved Great Lakes Power into a group of its own due to low customer density.[2] Subsequently, API put forward an analysis of cost drivers in the PEG total cost econometric benchmarking model in its 2014 IRM application (EB-2013-0110), submitting that these cost drivers and resulting coefficients are based on an industry average, and not representative of API as a statistical outlier. In its decision and order in the EB-2013-0110 application, the OEB found that:

> *Algoma's evidence illustrates that the PEG model, although applicable to the vast majority of distributors, may not apply to distributors that are particularly unique.*[3]

Despite the challenges that API has faced in respect of prior OEB benchmarking efforts, API is able to make use of trending information and other output from the PEG model, as discussed in Section 5.5.

[1] Benchmarking the Costs of Ontario Power Distributors, Pacific Economics Group, April 25, 2007 (PEG 2007), p.57
[2] PEG 2007, p.74
[3] EB-2013-0110, Decision and Order, February 20, 2014, pp.7-8

5.2. . Capital Investments

With respect to the Activity and Program Benchmarking (APB), API continues to monitor the annual APB updates issued by the OEB. API reviews its own year-over-year performance, as well as the performance compared to industry. While the reports may assist API in identifying opportunities to improve its per-unit costs, these opportunities may be limited due to factors outside of API's control (ex: degree of forestation or low customer density relative to other LDCs) and/or limited available information regarding the practices of high-performing LDCs.

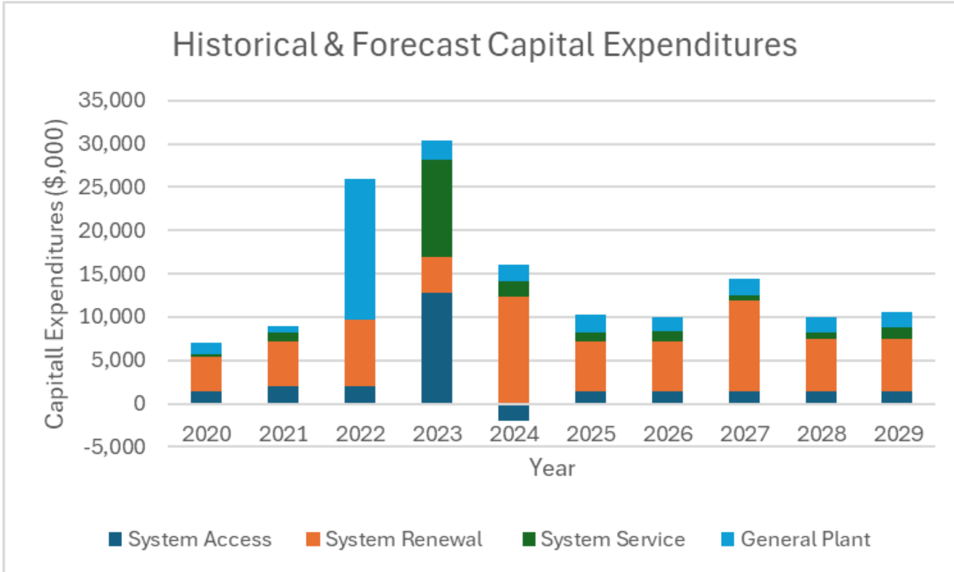
The following table summarizes API's historical distribution system investments, as well as forecasted investments in the 2024 Bridge Year, and the 2025-2029 period covered by its current DSP:

Table 5 – Historical and Forecast Distribution System Expenditures

Category	Historical ($ '000)					Forecast ($ '000)				
	2020	2021	2022	2023	2024[1]	2025	2026	2027	2028	2029
System Access (Gross)	1,519	2,488	2,082	12,989	3,295	1,465	1,489	1,511	1,534	1,557
System Renewal (Gross)	4,052	5,139	7,567	4,102	12,397	5,752	5,822	10,494	5,998	6,088
System Service (Gross)	259	980	32	11,393	1,684	1,054	1,110	652	753	1,310
General Plant (Gross)	1,425	819	16,386	2,241	1,901	2,039	1,718	1,855	1,787	1,785
Gross Capital Expenses	7,254	9,425	26,067	30,725	19,278	10,310	10,139	14,513	10,071	10,740
Contributed Capital	- 168	- 472	- 264	- 272	-5,252	- 100	- 102	- 104	- 106	- 108
Net Capital Expenses after Contributions	7,086	8,953	25,804	30,453	14,026	10,210	10,037	14,409	9,965	10,632
System O&M	7,078	7,171	7,388	7,605	7,883	9,275	9,530	9,792	10,061	10,338

API's capital planning process strives for relatively consistent year to year spending in its sustaining end of life asset replacement programs as well as other programs of a recurring nature. This approach allows API to optimize the use of internal resources and ensures asset replacement on a pace that is consistent with the expected useful life of each type of asset. Larger one-time projects such as substation rebuilds are also paced to keep spending consistent, to the extent possible.

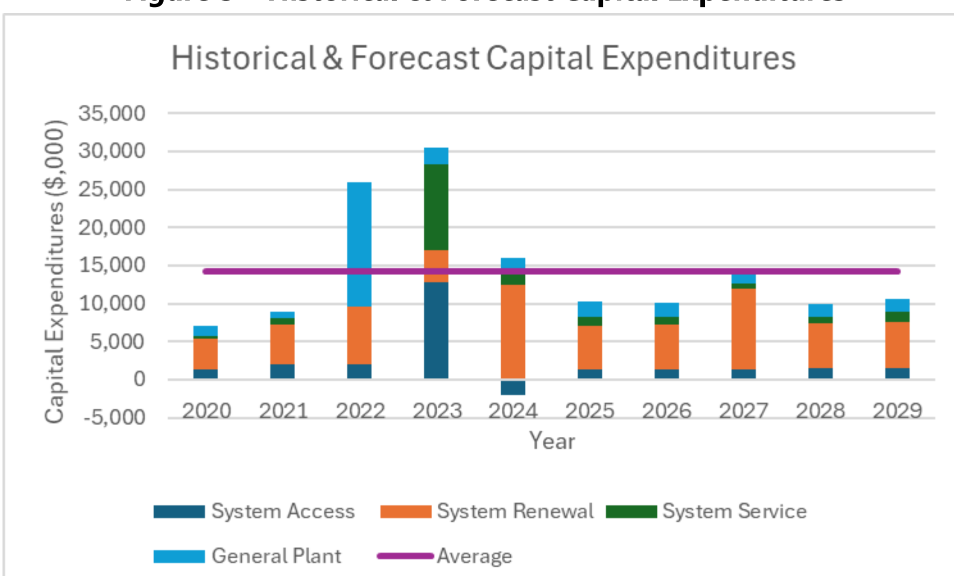
Figure 2 – Historical & Forecast Capital Expenditures



While the historical DSP period of 2020-2024 involved several large, one-time projects, the forecast period is more stable, and API does not anticipate the same level of year-over-year variability as prior years. The increase in 2022 is a result of API's SSM Facility, the increase in 2023 is related to the industrial customer-driven #4 Circuit Project and the Echo River TS Project, and the 2024 increase is related to the Bruce Mines Distribution Station rebuild project.

Conversely, the 2025-2029 period is relatively stable, with an increase in 2027 related to the Wawa #2 Distribution Station rebuild.

Figure 3 – Historical & Forecast Capital Expenditures



API has consistently and cost-effectively completed the majority of projects and programs identified in its 2020-2024 DSP, particularly in the System Access and System Renewal categories.

Occasionally, more discretionary projects and programs in the System Service and General Plant categories have been reprioritized during API's annual budgeting process. Detailed explanations for changes in prioritization of projects, due to pandemic impacts as well as customer requests, are detailed in the DSP.

API's target with respect to capital investments in the 2025-2029 period is to complete all of the projects and program-based replacements identified in its DSP. API will however maintain flexibility to reprioritize projects and/or adjust replacement rates based on updates to the inputs to its asset management process.

5.3. Operations, Maintenance and Administration (OM&A) Costs

The following table compares API's 2020 Board Approved and Test Year proposed OM&A costs.

Table 6 – 2020 Board Approved Compared to 2025 Test OM&A

	2020	2025	2020 BA to 2025 Test
	Board Approved	Test Year	Variance
Operations	$ 1,732,837	$ 2,563,055	$ 830,217
Maintenance	$ 5,282,210	$ 6,711,543	$ 1,429,333
Billing and Collecting	$ 986,414	$ 1,085,080	$ 98,665
Community Relations	$ 96,558	$ 75,220	-$ 21,338
Administrative and General	$ 5,559,123	$ 5,842,116	$ 282,994
Total OM&A	**$ 13,657,142**	**$ 16,277,014**	**$ 2,619,872**
LEAP	$ 31,140	$ 42,000	$ 10,860
Total OM&A incl. LEAP	**$ 13,688,282**	**$ 16,319,014**	**$ 2,630,732**

The primary drivers of the $2,630,732 increase from 2020 Board Approved to 2025 Test are:

- increased right of way maintenance (vegetation management) program costs per Appendix 2-JB of approximately $1,245,000;
- Increased right of way land fees of approximately $664,000;
- Increases in compensation costs of approximately $498,000, which are further detailed in Exhibit 4 and are shown to be trending consistently with industry inflation measures;
- increased shared service and corporate allocations per Appendix 2-N of approximately $403,000; and,
- the increases above are partially offset by total decreases of $(277,000), with the largest driver being related to a decrease in building rent following API's construction of the SSM Facility.

Table 7 – Summary of OM& A

	2020 Board Approved	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 1,732,837	$ 1,481,440	$ 1,624,753	$ 1,891,114	$ 2,001,412	$ 2,049,080	$ 2,563,055
Maintenance	$ 5,282,210	$ 5,596,378	$ 5,546,052	$ 5,496,523	$ 5,603,445	$ 5,834,295	$ 6,711,543
SubTotal	**$ 7,015,047**	**$ 7,077,818**	**$ 7,170,805**	**$ 7,387,637**	**$ 7,604,856**	**$ 7,883,376**	**$ 9,274,598**
%Change (year over year)		0.9%	1.3%	3.0%	2.9%	3.7%	17.6%
%Change (Test Year vs Last Rebasing Year - Actual)							31.0%
Billing and Collecting	$ 986,414	$ 951,794	$ 907,175	$ 891,233	$ 959,849	$ 1,039,479	$ 1,085,080
Community Relations	$ 96,558	$ 34,402	$ 52,871	$ 70,420	$ 68,681	$ 69,488	$ 75,220
Administrative and General	$ 5,589,735	$ 5,292,721	$ 5,477,480	$ 5,552,569	$ 5,360,101	$ 5,614,130	$ 5,884,116
SubTotal	**$ 6,672,707**	**$ 6,278,917**	**$ 6,437,526**	**$ 6,514,222**	**$ 6,388,631**	**$ 6,723,097**	**$ 7,044,416**
%Change (year over year)		-5.9%	2.5%	1.2%	-1.9%	5.2%	4.8%
%Change (Test Year vs Last Rebasing Year - Actual)							12.2%
Total	**$ 13,687,754**	**$ 13,356,735**	**$ 13,608,330**	**$ 13,901,859**	**$ 13,993,487**	**$ 14,606,472**	**$ 16,319,014**
%Change (year over year)		-2.4%	1.9%	2.2%	0.7%	4.4%	11.7%

5.4. Scorecard Metrics – Customer Focus

The OEB Scorecard contains six performance metrics related to the RRF outcome of Customer Focus, divided into categories of Service Quality and Customer Satisfaction.

Service Quality

API's historical performance has consistently exceeded OEB targets in all three Service Quality metrics, as summarized in the following charts produced from the OEB's Electricity Utility Performance Dashboard. API's future target is to maintain performance that meets or exceeds OEB targets and is consistent with historical performance levels.

Figure 4 – Services Connected on Time

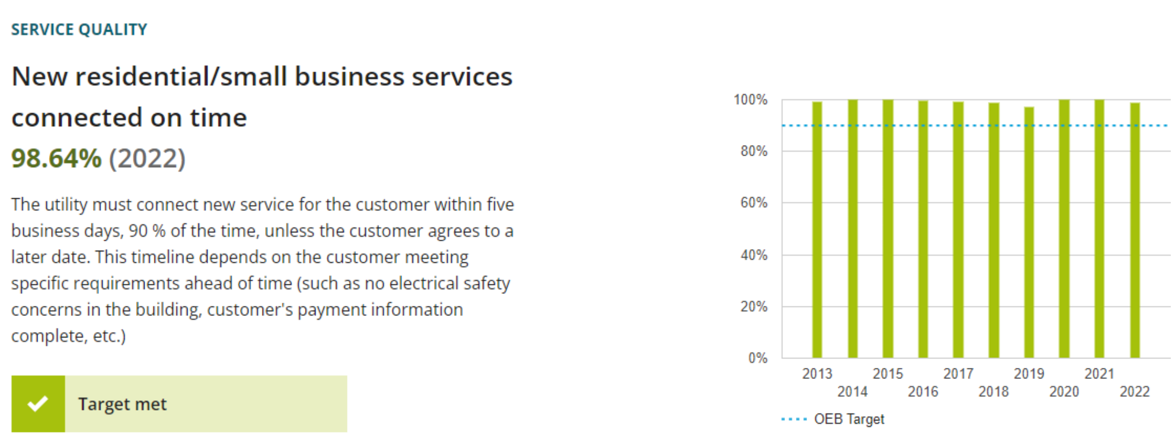


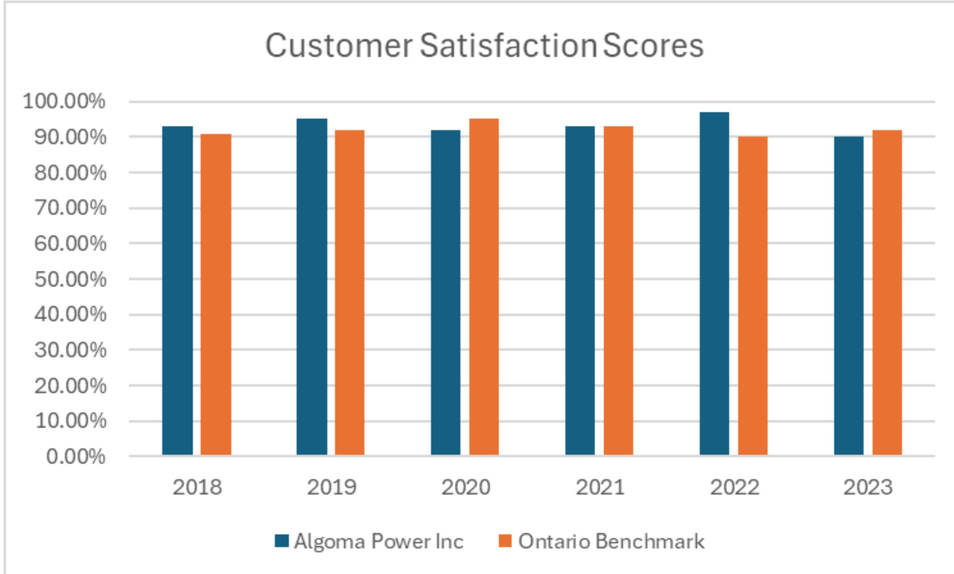
Figure 5 Scheduled Appointment on Time

Figure 6 Telephone Calls Answered on Time

Customer Satisfaction

API conducts annual customer satisfaction surveys to better understand and meet the needs of its customers. Since 2015, this survey has been completed by UtilityPULSE, which has allowed API to compare its results to an Ontario Benchmark that reflects the results of other LDCs working with this same provider. The following table indicates API's performance in comparison to the Ontario benchmark. Throughout the past 6 years, Algoma has exceeded the Ontario benchmark in three out of six years.

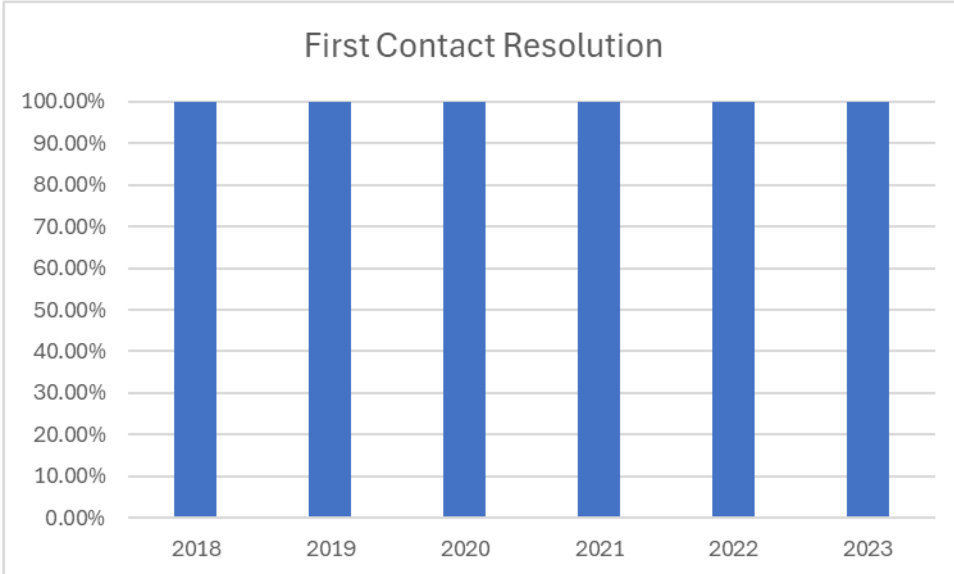
Figure 7 – Customer Satisfaction Scores



API's experience with customer satisfaction scores since 2015 is that year to year variations in its own results are generally similar to variations in the Ontario Benchmark, which can be driven by factors beyond API's control. In 2023, API conducted additional customer engagement activities related to its 2025 cost of service application (as described in Section 4.2), with the intent that a more granular understanding of customer preferences would inform the development of its DSP in a way that would meet customer expectations over the 2025-2029 planning period. API's future target is to continue to achieve customer satisfaction scores that exceed the Ontario Benchmark.

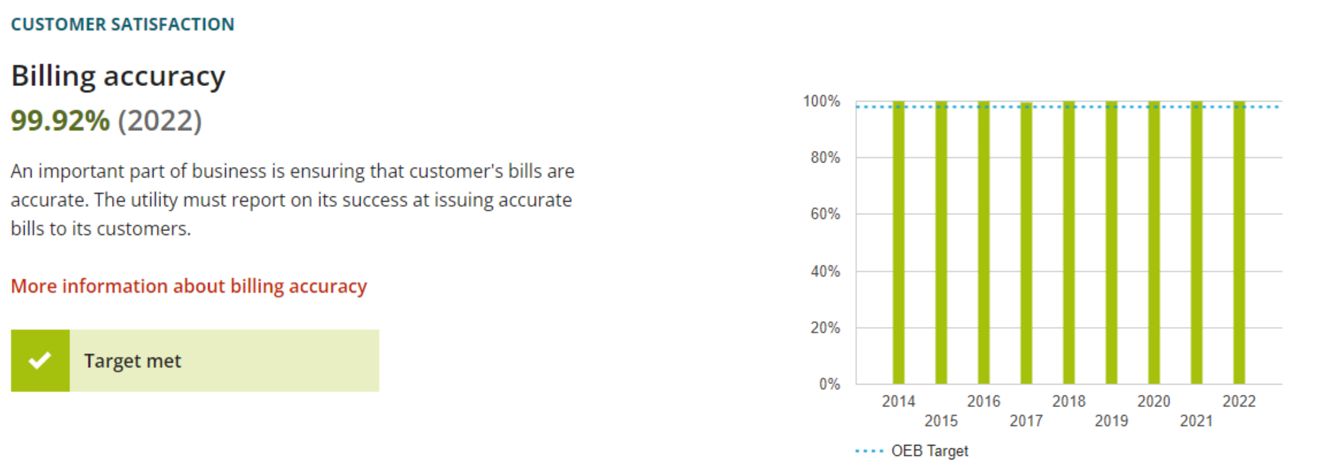
First Contact Resolution is a measure of the percentage of inbound calls that are resolved by the first point of contact (i.e. not escalated to a supervisor or more senior staff member). Less than 1% of calls have historically required escalation, and API expects to continue this level of performance.

Figure 8 – First Contact Resolution



The OEB target for Billing Accuracy is 98%. API has consistently exceeded this target, and intends to continue this performance level in future years.

Figure 9 – Billing Accuracy



5.5. Scorecard Metrics – Operational Effectiveness

The OEB Scorecard contains ten performance metrics related to the RRF outcome of Operational Effectiveness, divided into categories of Safety, System Reliability, Asset Management and Cost Control.

Safety

An unrelenting commitment to safety is entrenched in API's core values and a focus on both worker and public safety will always be included among API's strategic objectives.

In 2020 and 2022, UtilityPULSE was engaged to complete surveys in relation to “Public Awareness of Electrical Safety”. On completion of this survey, UtilityPulse generated a “Public Safety Awareness Index Score” for API and other LDC’s. API’s 2020 score was 83%, and its 2022 score was 82%. This survey will continue to be completed on a biannual basis. API plans to continue to deliver and improve on its public outreach initiatives related to safety, with a goal on improving its Public Safety Awareness Index Score with each survey.

Over the 2019-2023 period, API has consistently achieved full compliance with Ontario Regulation 22/04, and has had no serious electrical incidents involving the public. API’s target is to continue to achieve full compliance and to have zero serious safety incidents.

System Reliability

The OEB Scorecard includes SAIDI and SAIFI performance metrics that provide an indication of the average number of hours and the average number of times that power to a customer is interrupted. Scorecard results are adjusted to focus on outages that are within the LDC’s control by removing outages associated with Loss of Supply, and Major Event Days. API’s target is to achieve adjusted reliability results in any given year that are better than its historical rolling 5-year average.

In API’s experience, while customers are more understanding of outages during major storm events, all outages, regardless of cause or responsibility, ultimately affect customers’ perceptions of the reliability of API’s system. API therefore regularly reviews SAIDI and SAIFI results and trending for all outages and adjusted values.

API continues to target continuous improvement in its reliability performance. API’s sustaining asset replacement, vegetation management, and Protection, Automation, Reliability programs directly target reliability improvements, in addition to other projects and programs. API has demonstrated continuous improvements in its outage performance, and has consistently exceeded its scorecard performance targets, last established in 2020 during the current DSP term.

Figure 10 – Performance Measure SAIDI

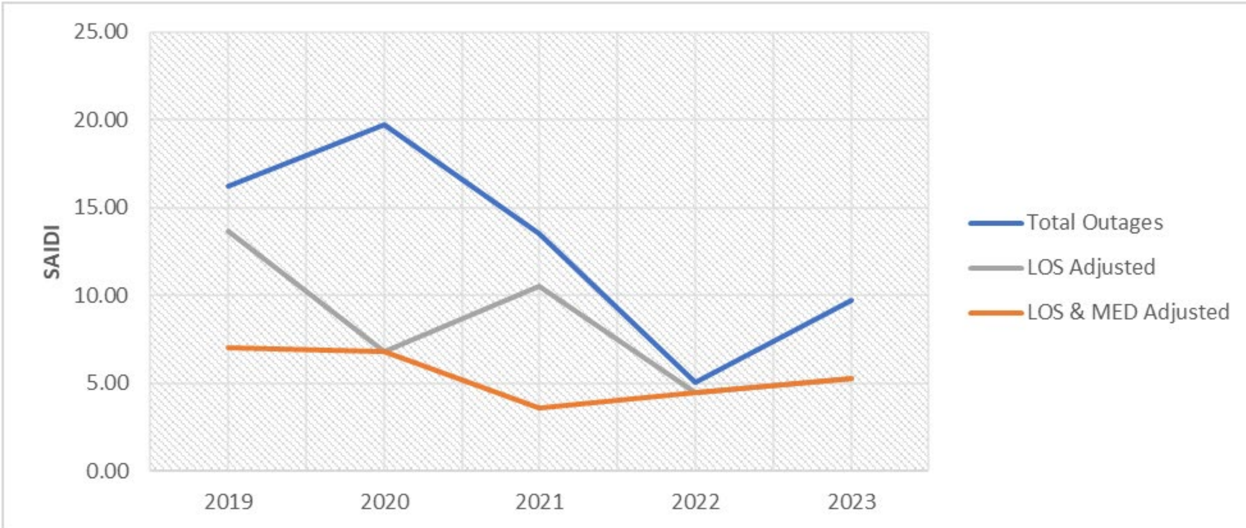
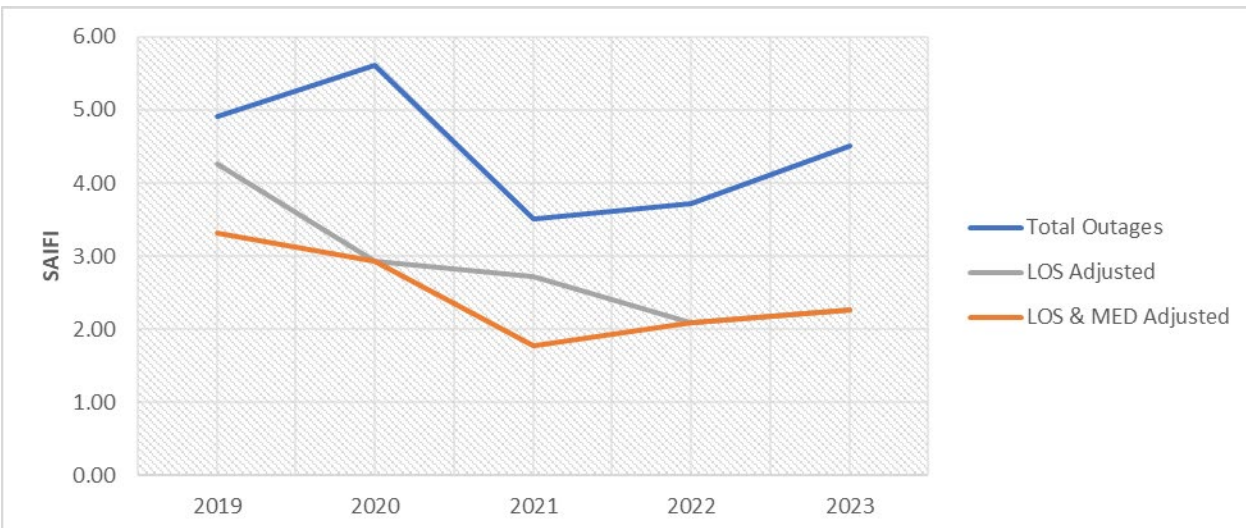


Figure 11 – Performance Measure SAIFI



Asset Management

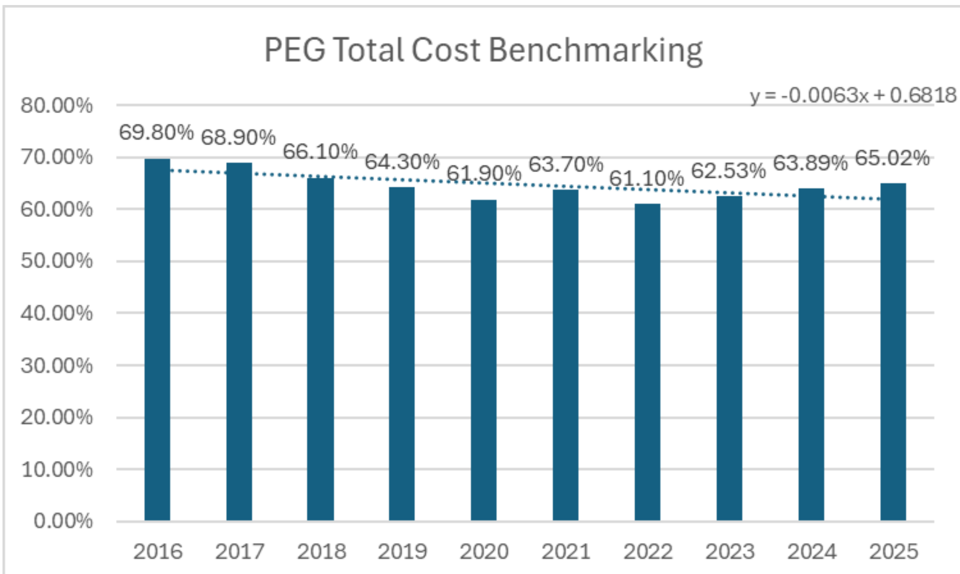
From 2014-2023, API has reported its Distribution System Plan Implementation Progress as "completed". Further details on API's assessment considerations for this measure are provided in the DSP.

Cost Control

Cost control performance metrics included in the OEB Scorecard are driven by the output of the OEB's total cost benchmarking framework, particularly the Total Cost Benchmarking model compiled and updated by Pacific Economics Group (the "PEG Model"). API's historical challenges with the PEG Model are summarized in Section 5.1. As a result of these issues, API has focused on trending and cost drivers in its analysis of historical results and setting of future targets.

The PEG Model calculates each LDC's Total Cost by adding the majority of OM&A accounts from the LDC's trial balance, and determining a proxy for capital costs based on historical and current capital additions, an asset price index, an economic depreciation rate, and a rate of return. The PEG Model also calculates a "Predicted Total Cost" for each LDC, using a standard formula that considers business conditions such as number of customers, load, km of line, etc. The percentage difference between actual and predicted cost is the PEG Model measure of cost performance, where lower percentage results indicate greater efficiency. The following chart shows API's cost performance, according to the PEG model:

Figure 12 – PEG Total Cost Benchmarking



For the reasons summarized in Section 5.1, API does not believe that the PEG model cost predictions accurately reflect the cost drivers inherent to API's distribution system and service area. Since API's inputs to the PEG Model remain relatively stable year-over-year however, the trending in cost performance provides useful insight into whether API's cost efficiency is improving over time. The 2016-2025 trend indicates that API's is becoming more efficient over the ten-year period. Annual variations in the results can be caused by one-time capital additions, such as the Sault Facility investment in 2022, and as such, API is focused on the overall trend as opposed to slight variability in the year-over-year results.

5.6. Scorecard Metrics – Public Policy Responsiveness

The OEB Scorecard performance measures for Public Policy Responsiveness are now related to Connection of Renewable Generation, since Conservation and Demand Management targets have been removed from the scorecard.

API has consistently met or exceeded OEB targets related to completing impact assessments and connecting renewable generation on time.

5.7. Financial Performance

Scorecard Metrics – Financial Performance

The following table summarizes API's Scorecard financial ratios for the 2013-2018 period:

Table 8 – Scorecard Financial Ratios

	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Leverage: Total Debt (includes short-term and long-term debt) to Equity	Profitability (Approved ROE)	Regulatory Return on Equity (Achieved ROE)
2020	0.77	1.30	8.52%	9.25%
2021	0.43	1.32	8.52%	9.38%
2022	0.26	1.44	8.52%	10.53%
2023*	0.20	1.39	8.52%	10.54%
	*Based on numbers drafted for 2023 OEB RRR filings, as of application filing date			

API's future target is to achieve its deemed return on equity while maintaining liquidity and leverage ratios that are relatively consistent with historical levels.

Revenue Requirement / Revenue Deficiency

The following table presents API's Revenue Requirement trend from the 2020 Board Approved to 2025 Test Year:

Table 9 – Trend in Revenue Requirement

	CGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Item	**2020 Board Approved**	**2020**	**2021**	**2022**	**2023**	**2024 Bridge**	**2025 Test**
OM & A Expenses	$13,687,754	$ 13,356,735	$ 13,608,330	$ 13,901,859	$ 13,993,487	$ 14,606,472	$ 16,319,014
Depreciation Expense	$ 4,034,602	$ 3,924,249	$ 4,049,472	$ 4,188,459	$ 4,297,723	$ 4,828,861	$ 5,675,782
Property Taxes	$ 118,600	$ 120,695	$ 146,380	$ 141,693	$ 243,806	$ 350,000	$ 260,000
Total Distribution Expenses	$17,840,956	$ 17,401,679	$ 17,804,182	$ 18,232,011	$ 18,535,016	$ 19,785,333	$ 22,254,796
Regulated return on Capital	$ 8,184,098	$ 7,918,581	$ 8,133,195	$ 8,467,199	$ 9,124,336	$ 10,801,134	$ 12,555,753
Grossed up Income Tax	$ 259,084	$ 635,374	$ 734,407	$ 258,575	-$ 227,130	$ 203,603	$ 958,002
Service Revenue Requirement	**$26,284,138**	**$ 25,955,634**	**$ 26,671,784**	**$ 26,957,785**	**$ 27,432,222**	**$ 30,790,070**	**$ 35,768,551**
Less:Revenue Offsets	-$ 488,791	-$ 444,041	-$ 619,526	-$ 706,011	-$ 1,579,997	-$ 1,911,647	-$ 656,000
Base Revenue Requirement	**$25,795,347**	**$ 25,511,593**	**$ 26,052,258**	**$ 26,251,774**	**$ 25,852,225**	**$ 28,878,423**	**$ 35,112,551**

API's 2025 cost of service application is intended to set rates that will recover the 2025 base revenue requirement identified in Table 5 above of $35,112,551. This includes the recovery of OM&A expenses, depreciation expense, property taxes, regulated return on capital and grossed up PILs. The 2025 proposed service revenue requirement would be an increase of $9,484,413 or approximately 36.1%. Table 6 on the following page illustrates that revenues at current rates are insufficient to recover this revenue requirement, resulting in a net revenue deficiency of $3,193,707. The main drivers of revenue requirement changes are increase in power supply, increase in rate base and increase in depreciation expense, The increase in power supply is predominantly due to an increase in the forecasted load, brought about by industrial customer growth.An increase in regulated return of capital and depreciation expense are impacted by an increase in capital assets, attributed to the completion of API's prior DSP (which included several one-time projects), as well as an un-forecasted industrial customer driven project (the #4 Circuit Project).

Table 10 - Revenue Requirement Summary

Driver	2020 Board Appr	2025 Test Year
Long Term Debt Rate	5.81%	5.59%
Short Term Debt Rate	1.76%	6.23%
Weighted Average Debt Rate	5.54%	5.63%
Rate of Return on Equity	8.78%	9.21%
Regulated Rate of Return on Rate Base	**6.84%**	**7.06%**
Controllable Expenses	$ 13,806,882	$ 16,579,014
Power Supply Expense	$ 23,416,069	$ 32,534,015
Working Capital Base	**$ 37,222,951**	**$ 49,113,029**
Working Capital Allowance Rate	7.50%	7.50%
Working Capital Allowance ("WCA")	**$ 2,791,721**	**$ 3,683,477**
Net Fixed Assets Opening Test Year	$ 114,801,408	$ 172,167,954
Net Fixed Assets Closing Test Year	$ 119,056,280	$ 176,058,022
Average Net Fixed Assets	$ 116,928,844	$ 174,112,988
Working Capital Allowance	$ 2,791,721	$ 3,683,477
Rate Base	**$ 119,720,565**	**$ 177,796,465**
Deemed Interest Expense	$ 3,979,512	$ 6,005,731
Target Return on Deemed Equity	$ 4,204,586	$ 6,550,022
Regulated Return on Rate Base	**$ 8,184,098**	**$ 12,555,753**
Regulated Return on Rate Base	$ 8,184,098	$ 12,555,753
OM&A	$ 13,687,754	$ 16,319,014
Property Taxes	$ 118,600	$ 260,000
Depreciation Expense	$ 4,034,602	$ 5,675,782
Income Taxes	$ 259,084	$ 958,002
Service Revenue Requirement	**$ 26,284,138**	**$ 35,768,551**
Revenue Offset	-$ 488,791	-$ 656,000
Base Revenue Requirement	**$ 25,795,347**	**$ 35,112,551**

Please Refer to exhibit 6 section 6.3.2 for further information on the causes of the change in the base revenue requirement of 2020 Board approved to the 2025 test.

Table 11 – Calculation of 2025 Revenue Deficiency

	At Current Approved Rates	At Proposed Rates
Revenue Deficiency from Below		$ 3,193,707
Distribution Revenue	$ 31,918,843	$ 31,918,843
Other Operating Revenue Offsets - net	$ 656,000	$ 656,000
Total Revenue	$ 32,574,843	$ 35,768,551
Operating Expenses	$ 22,254,796	$ 22,254,796
Deemed Interest Expense	$ 6,005,731	$ 6,005,731
Total Cost and Expenses	$ 28,260,527	$ 28,260,527
Utility Income Before Income Taxes	$ 4,314,316	$ 7,508,024
Tax Adjustmnets to Accounting	-$ 3,892,922	-$ 3,892,922
Income per PILs Model		
Taxable Income	$ 421,394	$ 3,615,102
Income Tax Rate	26.50%	26.50%
Income Tax on Taxable Income	$ 111,670	$ 958,002
Income Tax Credits	$ -	$ -
Utility Net Income	$ 4,202,647	$ 6,550,022
Utility Rate Base	$ 177,833,127	$ 177,796,465
Deemed Equity Portion of Rate Base	$ 71,133,251	$ 71,118,586
Income/(Equity Portion of Rate Base)	5.91%	9.21%
Target Return - Equity on Rate Base	9.21%	9.21%
Deficiency/Sufficiency in Return on Equity	-3.30%	0.00%
Indicated Rate of Return	5.74%	7.06%
Requested Rate of Return on Rate Base	7.06%	7.06%
Deficiency/Sufficency in Rate of Return	-1.32%	0.00%
Target Return on Equity	$ 6,550,022	$ 6,550,022
Revenue Deficiency/(Sufficiency)	$ 2,347,375	$ -
Gross Revenue Deficiency/(Sufficiency)	$ 3,193,707	

Further explanation of the calculation of the revenue deficiency can be found at exhibit 6 section 6.3.1.

Load Forecast

Exhibit 3 provides further detail pertaining to the load forecast. Identification on the methodology and processes used to complete the forecast are explained in detail in exhibit 3. The tables below indicate both the quantity and percentage difference between the 2020 board approved and 2025 test year values for customers/devices, kWh and kW.

Table 12 – Forecasted Customers for 2020 Board Approved & 2025 Test Year

Rate Class	2020 Board Approved	2025 Test Year	Variance	Variance %
Residential	8,116	8,621	505	6.22%
General Service <50 kW	997	1,053	56	5.62%
General Service 50 to 4,999 kW	37	45	8	21.62%
Seasonal	2,960	2,717	-243	-8.21%
Street Lights (devices)	1,128	1,156	28	2.48%
Total	13,238	13,592	354	2.67%

Overall customers/connections from 2020 board approved to 2025 test year is anticipated to increase by 2.67% with the rate class General service > 50 anticipated to have the largest increase of 21.62%. Positive growth is expected in every customer/connection rate class besides seasonal which is projected to have a decrease of 8.32%. Further information can be reviewed in Exhibit 3 for customer growth.

Table 13 – Forecasted kWh for 2020 Board Approved & 2025 Test Year

Rate Class	2020 Board Approved	2025 Test Year	Variance	Variance %
Residential	84,857,056	102,025,758	17,168,702	20.23%
General Service <50 kW	28,480,011	29,627,607	1,147,596	4.03%
General Service 50 to 4,999 kW	107,645,160	179,389,418	71,744,258	66.65%
Seasonal	5,874,372	5,958,052	83,680	1.42%
Street Lights	581,104	548,977	- 32,127	-5.53%
Total	227,437,702	317,549,813	90,112,111	39.62%

The 2020 Board approved consumption to the 2025 test year has overall increased by 39.62% driven significantly by the anticipated increase in General Service >50kW (R2) load in 2025. The Streetlighting class has negative growth due to technological advancements of LED streetlights. Additional information regarding annual usage per customer can be found in Exhibit 3.

Table 14 – Forecasted kW for 2020 Board Approved & 2025 Test Year

Rate Class	2020 Board Approved	2025 Test Year	Variance	Variance %
Residential				
General Service < 50 kW				
General Service 50 to 4,999 kW	248,605	372,457	123,852	49.82%
Seasonal				
Street Lights	1,615	1,533	- 82	-5.08%
Total	250,220	373,990	123,770	49.46%

Consistent with the change in kWh, the increase in kW demand is attributable primarily to forecasted increases in the 2025 General Service >50kW customer class (R2), enabled by a significant recent expansion project. API notes that distribution rates for street lighting customers are based on the kWh consumed not kW demand. kW demand is used in the billing of transmission rates for this class.

Table 15 - Rate Base Board Approved & Test

Item	2020 Board Appr	2025 Test Year	Difference	% Difference
Controllable Expenses	$ 13,806,882	$ 16,579,014	$ 2,772,132	20.1%
Power Supply Expense	$ 23,416,069	$ 32,534,015	$ 9,117,946	38.9%
Working Capital Base	**$ 37,222,951**	**$ 49,113,029**	**$11,890,078**	**31.9%**
Working Capital Allowance Rate	7.50%	7.50%	0.00%	0.0%
Working Capital Allowance ("WCA")	**$ 2,791,721**	**$ 3,683,477**	**$ 891,756**	**31.9%**
Net Fixed Assets Opening Test Year	$ 114,801,408	$ 172,167,954	$57,366,546	50.0%
Net Fixed Assets Closing Test Year	$ 119,056,280	$ 176,058,022	$57,001,742	47.9%
Average Net Fixed Assets	$ 116,928,844	$ 174,112,988	$57,184,144	48.9%
Working Capital Allowance	$ 2,791,721	$ 3,683,477	$ 891,756	31.9%
Rate Base	**$ 119,720,565**	**$ 177,796,465**	**$58,075,900**	**48.5%**

The proposed rate base for the 2025 test year is $177,796,465 which is an increase of $58,075,900 from last board approved rate base. The principal contributors to this increase are;

- Gross Fixed Assets has increased due to regular program spending and four unusual projects explained in Exhibit 2.1.2
- Accumulated Depreciation increase due to the increase in gross fixed assets.
- Working Capital Allowance increase due to power supply expenses increase and OM & A , further explained in Exhibit 2.1.2.

Table 16 – Working Capital Allowance Summary

Description	2020 BA	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test	Variance 2020BA to 2025 TY	% Variance
Distribution Expenses - Operation	$ 1,732,837	$ 1,481,440	$ 1,624,753	$ 1,891,114	$ 2,001,412	$ 2,049,080	$ 2,563,055	$ 830,217	47.9%
Distribution Expenses - Maintenance	$ 5,282,210	$ 5,596,378	$ 5,546,052	$ 5,496,523	$ 5,603,445	$ 5,834,295	$ 6,711,543	$ 1,429,333	27.1%
Billing and Collecting	$ 986,414	$ 951,794	$ 907,175	$ 891,233	$ 959,849	$ 1,039,479	$ 1,085,080	$ 98,665	10.0%
Community Relations	$ 96,558	$ 34,402	$ 52,871	$ 70,420	$ 68,681	$ 69,488	$ 75,220	-$ 21,338	-22.1%
Administrative and General Expenses	$ 5,559,123	$ 5,262,108	$ 5,446,867	$ 5,521,956	$ 5,329,489	$ 5,583,518	$ 5,842,116	$ 282,994	5.1%
Taxes Other Than Income Taxes	$ 118,600	$ 120,695	$ 146,380	$ 141,693	$ 243,806	$ 350,000	$ 260,000	$ 141,400	119.2%
Donations - LEAP	$ 31,140	$ 52,205	$ 23,016	$ 39,910	$ 52,475	$ 57,500	$ 42,000	$ 10,860	34.9%
Power Supply Expenses	$23,416,069	$30,169,802	$26,958,875	$29,360,809	$28,238,726	$28,298,495	$32,534,015	$ 9,117,946	38.9%
Total Expenses for Working Capital	$37,222,951	$43,668,825	$40,705,989	$43,413,659	$42,497,881	$43,281,855	$49,113,029	$ 11,890,078	31.9%
Working Capital Rate (%)	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	0.0%	0.0%
Allowance for Working Capital	$ 2,791,721	$ 3,275,162	$ 3,052,949	$ 3,256,024	$ 3,187,341	$ 3,246,139	$ 3,683,477	$ 891,756	31.9%

The 7.5% allowance approach was used for the derivation of working capital. Further information can be found in exhibit 2 section 2.4.

Table 17 – Proposed Revenue to Cost Ratios

Class	Revenue Requirement - 2025 Cost Allocation Model - Line 40 from O1 in CA	2025 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2025 Cost Allocation Model - Line 19 from O1 in CA	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2025 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High
Residential - R1 (i)	23,409,433	23,507,630	443,238	23,950,868	102.31%	102.31%	102.31%	23,950,868	443,238	23,507,630	85%	115%
Residential - R1 (ii)											80%	120%
Residential - R2	7,356,168	8,148,808	108,195	8,257,003	112.25%	112.25%	108.56%	7,986,222	108,195	7,878,027	80%	120%
Seasonal	4,438,267	3,221,400	90,830	3,312,230	74.63%	74.63%	79.81%	3,542,354	90,830	3,451,524	85%	115%
Street Lighting	564,683	234,712	13,737	248,449	44.00%	44.00%	51.20%	289,107	13,737	275,369	80%	120%
TOTAL	35,768,551	35,112,551	656,000	35,768,551				35,768,551	656,000	35,112,551		

For the seasonal class and street lighting the revenue to cost ratio was below the OEB's policy limit of 85% and 80% respectfully. A phased rebalancing of revenue to cost ratios among rate classes to achieve the OEB's policy limit is explained in Exhibit 7. Phased rebalancing has been proposed over multiple years to address bill mitigation requirements in these classes.

Table 18 – Group 1 & 2 DVA Account Balances as of December 31, 2023

Account Descriptions	Account Number	Closing Principal Balance as of Dec-31-23	Closing Interest Amounts as of Dec-31-23	Closing Principal + Interest Balance as of Dec-31-23	Accounts to Dispose Yes/No	Total $ Claim	Allocator	Continued or Discontinued	API Specific Accounts Yes/No	Other Notes
Group 1 Accounts										
Smart Metering Entity Charge Variance Account	1551	(53,393)	(2,226)	(55,619)	Yes	(23,550)	# of Customers	Continued	No	
RSVA - Wholesale Market Service Charge	1580	236,573	33,592	270,165	Yes	(292,020)	kWh	Continued	No	
Variance WMS – Sub-account CBR Class A	1580	-	-	-	No	-	N/A	Continued	No	
Variance WMS – Sub-account CBR Class B	1580	(2,280)	(2,739)	(5,019)	Yes	29,044	kWh	Continued	No	
RSVA - Retail Transmission Network Charge	1584	205,875	19,920	225,795	Yes	1,507	kWh	Continued	No	
RSVA - Retail Transmission Connection Charge	1586	277,334	15,503	292,837	Yes	106,567	kWh	Continued	No	
RSVA - Power (excluding Global Adjustment)	1588	324,926	23,892	348,818	Yes	383,065	kWh	Continued	No	
RSVA - Global Adjustment	1589	(252,186)	(14,036)	(266,222)	Yes	(292,802)	Non-RPP kWh	Continued	No	
Disposition and Recovery/Refund of Regulatory Balances (2018 and pre-2018)[3]	1595	(70,374)	-	(70,374)	No	-	N/A	Continued	No	A 1595 (2010) balance, riders expired Dec 31, 2023.
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	-	(1)	(1)	No	-	N/A	Discontinued	No	Disposition in 2023.
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	(130,266)	(21,898)	(152,164)	No	-	N/A	Discontinued	No	Last riders expired Dec 31, 2023.
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	(41,609)	(5,273)	(46,882)	Yes	(46,882)	%	Continued	No	Riders expired Dec 31, 2021.
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	(141,505)	(7,182)	(148,687)	No	-	N/A	Continued	No	Riders expired Dec 31, 2022.
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	(40,540)	-	(40,540)	No	-	N/A	Continued	No	Riders expired Dec 31, 2023.
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	-	-	-	No	-	N/A	Continued	No	Riders expire Dec 31, 2024.
Total Group 1 Accounts		**312,555**	**39,552**	**352,107**		**(135,071)**				
Group 2 Accounts										
Pole Attachment Revenue Variance	1508	273,248	7,997	281,245	Yes	296,246	Distribution Rev.	Continued	No	Updated rate in base rates.
Other Regulatory Assets - Sub-Account - Pension Deferral	1508	6,412,279	-	6,412,279	No	-	N/A	Continued	Yes	
Other Regulatory Assets - Sub-Account - Pension Expense Variance	1508	(8,880,034)	-	(8,880,034)	No	-	N/A	Continued	Yes	
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Deferral	1508	2,518,700	-	2,518,700	No	-	N/A	Continued	Yes	
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Expense	1508	(5,165,139)	-	(5,165,139)	No	-	N/A	Continued	Yes	
Other Regulatory Assets - Sub-Account - Dubreuilville Costs & Revenues	1508	(65,190)	-	(65,190)	Yes	(65,190)	kWh	Discontinued	Yes	Rider specific to former DLI customers calculated outside of DVA model.
Other Regulatory Assets - Sub-Account - Retail Service Charges	1508	(2,742)	(240)	(2,982)	Yes	(3,133)	kWh	Discontinued	No	Updated charges in rev req.
Other Regulatory Assets - Sub-Account - Amortized Pension Actuarial Gains/Losses	1508	199,896	15,278	215,174	Yes	226,148	kWh	Continued	Yes	
Other Regulatory Assets - Sub-Account - Amortized OPEB Actuarial Gains/Losses	1508	(237,903)	(7,370)	(245,273)	Yes	(258,334)	kWh	Continued	Yes	
Other Regulatory Assets, Sub-account Incremental Capital Expenditures - Sault Building	1508	16,454,041	798,103	17,252,144	No	-	N/A	Discontinued	Yes	See Other Regulatory Assets, Sub-account ACM True-up.
Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues - Sault Building	1508	(2,159,586)	(84,736)	(2,244,322)	No	-	N/A	Discontinued	Yes	See Other Regulatory Assets, Sub-account ACM True-up.
Other Regulatory Assets, Sub-account Incremental Capital Expenditures - Echo River	1508	10,851,932	-	10,851,932	No	-	N/A	Discontinued	Yes	See Other Regulatory Assets, Sub-account ACM True-up.
Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues - Echo River	1508	(553,634)	(22,160)	(575,794)	No	-	N/A	Discontinued	Yes	See Other Regulatory Assets, Sub-account ACM True-up.
Other Regulatory Assets, Sub-account ACM True-up	1508	(1,007,183)	(300,727)	(1,307,910)	Yes	(1,307,910)	kWh	Discontinued	Yes	Final true-up of ACM projects.
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	1522	-	(212,377)	(212,377)	Yes	(313,498)	kWh	Continued	No	
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	(259,900)	(26,816)	(286,716)	Yes	(286,716)	kWh	Continued	No	ACM project PILs true-up.
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	(269,942)	(26,028)	(295,970)	Yes	(310,790)	kWh	Continued	No	API has proposed PILS smoothing for 2025 Test. Keep open in case of future announcements.
LRAM Variance Account	1568	-	-	-	No	-	N/A	Continued	No	
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential	1522	(1,841,912)	-	(1,841,912)	Yes	(1,841,912)	kWh	Continued	No	
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account	1522	1,841,912	-	1,841,912	Yes	1,841,912	kWh	Continued	No	
Accounting Changes Under CGAAP Balance + Return Component	1576	84,971	-	84,971	Yes	84,971	kWh	Discontinued	No	
Total Group 2 Accounts		**18,193,814**	**140,924**	**18,334,738**		**(1,938,206)**				

The descriptions for the accounts are provided in exhibit 9 section 9.3.2. Explanations of the transaction activity, methodology and disposition propsals can be found in Exhibit 9.

Table 19 – Bill Impacts for 2025 Test Year

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Consumption (kWh)	Demand kW (if applicable)	Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).
Residential R1(i)	750		1
Residential R1(ii)	2,000	-	1
Residential R2	225,000	500	1
Seasonal	200		1
Seasonal-10th percentile	3,000	10	75
Street Lighting	15		1

	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
Classification	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Residential R1(i)	$ (6.05)	-14.61%	$ (7.65)	-14.94%	$ (9.87)	-14.83%	$ (9.23)	-6.35%
Residential R1(ii)	$ (2.23)	-2.02%	$ (6.51)	-4.80%	$ (12.42)	-7.04%	$ (11.59)	-3.00%
Residential R2	$ (1,439.43)	-54.42%	$ (6,915.23)	-198.66%	$ (7,447.44)	-105.22%	$ (8,309.25)	-24.31%
Seasonal	$ 10.48	10.95%	$ 10.18	10.33%	$ 9.58	9.34%	$ 8.98	7.58%
Seasonal-10th percentile	$ 9.24	10.42%	$ 9.22	10.33%	$ 9.17	10.24%	$ 8.59	10.02%
Street Lighting	$ 218.18	17.11%	$ 155.19	12.18%	$ 147.50	11.12%	$ 139.38	8.99%

	Distribution				Total Bill			
Classification	**Current Bill**	**2025 Propose**	**Change ($)**	**Change (%)**	**Current Bill**	**2025 Propose**	**Change ($)**	**Change (%)**
Residential R1(i)	$ 41.39	$ 35.34	$ (6.05)	-14.6%	$ 145.34	$ 136.11	$ (9.23)	-6.35%
Residential R1(ii)	$ 110.04	$ 107.81	$ (2.23)	-2.0%	$ 386.22	$ 374.63	$ (11.59)	-3.00%
Residential R2	$ 2,644.81	$ 1,205.38	$ (1,439.43)	-54.4%	$ 34,173.69	$ 25,864.44	$ (8,309.25)	-24.31%
Seasonal	$ 95.75	$ 106.23	$ 10.48	10.9%	$ 118.42	$ 127.41	$ 8.98	7.58%
Seasonal-10th percentile	$ 88.65	$ 97.88	$ 9.24	10.4%	$ 85.80	$ 94.39	$ 8.59	10.02%
Street Lighting	$ 1,275.00	$ 1,493.18	$ 218.18	17.1%	$ 1,549.84	$ 1,689.23	$ 139.38	8.99%

Detailed Bill impact information is provided in exhibit 8 section 8.3.13. For RRRP-protected customer classes, distribution rate impacts are driven by the RRRP percentage adjustment, rather than adjustments in the revenue requirement allocated to these classes. The reduction in these classes can be attributed to Group 2 and/or Global Adjustment rate riders which represent material credit rate riders.

Attachment 1C

Executive Certification

Algoma Power Inc.
EB-2024-0007

Certification of Evidence

I, Duane Fecteau, Vice President of Finance and CFO, hereby certify the following regarding Algoma Power Inc. (API)'s Cost of Service Application and Evidence:

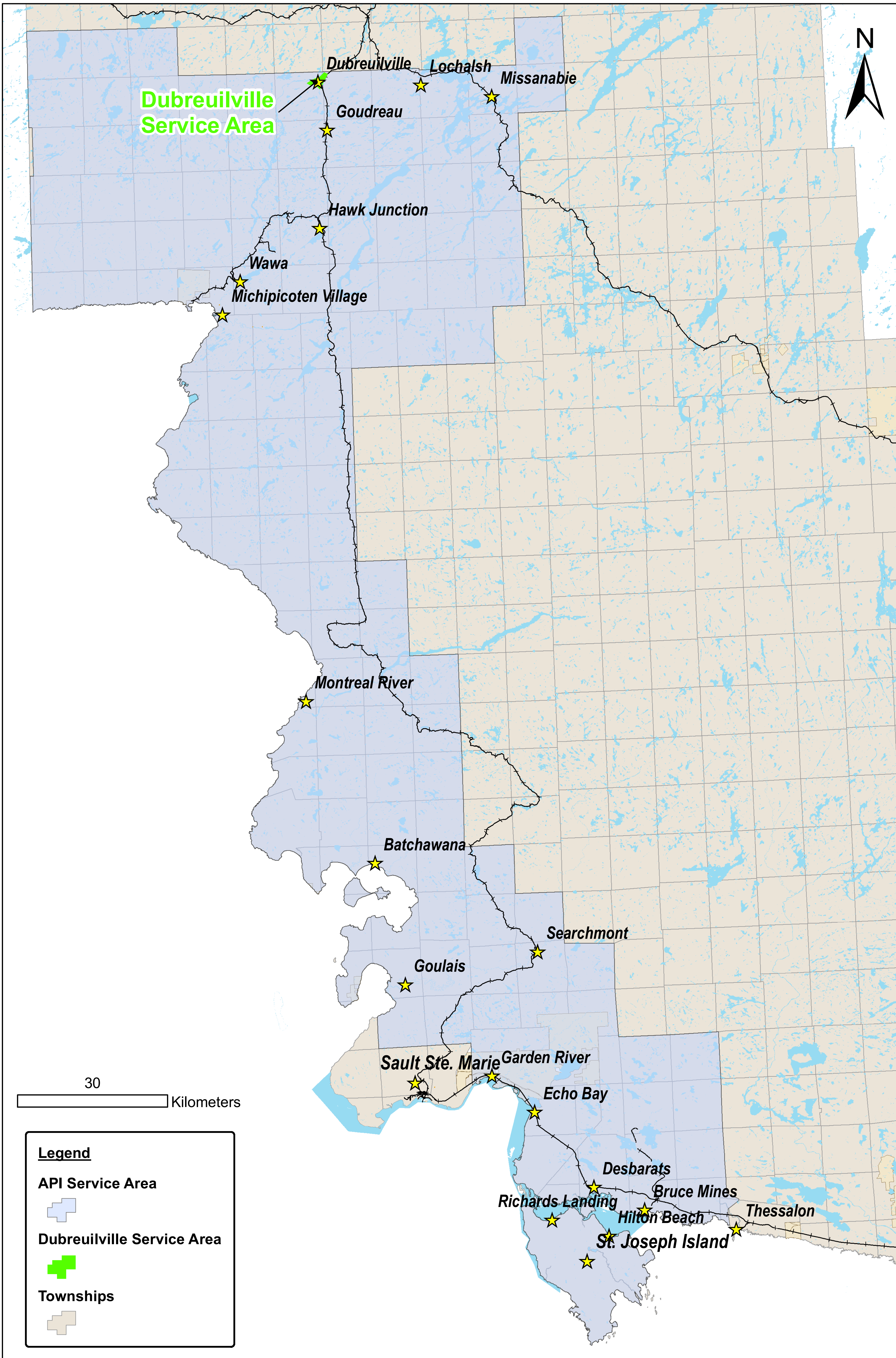
1. That the evidence does not include any personal information (as that phrase is defined in the Freedom of Information and Protection of Privacy Act), that is not otherwise redacted in accordance with rule 9A of the OEB's Rules of Practice and Procedure;
2. That the exhibits, models, and appendices are accurate, consistent and complete to the best of my knowledge;
3. That API has appropriate processes and internal controls for the preparation, review, verification and oversight of its deferral and variance accounts.

Duane Fecteau **May 31, 2024**

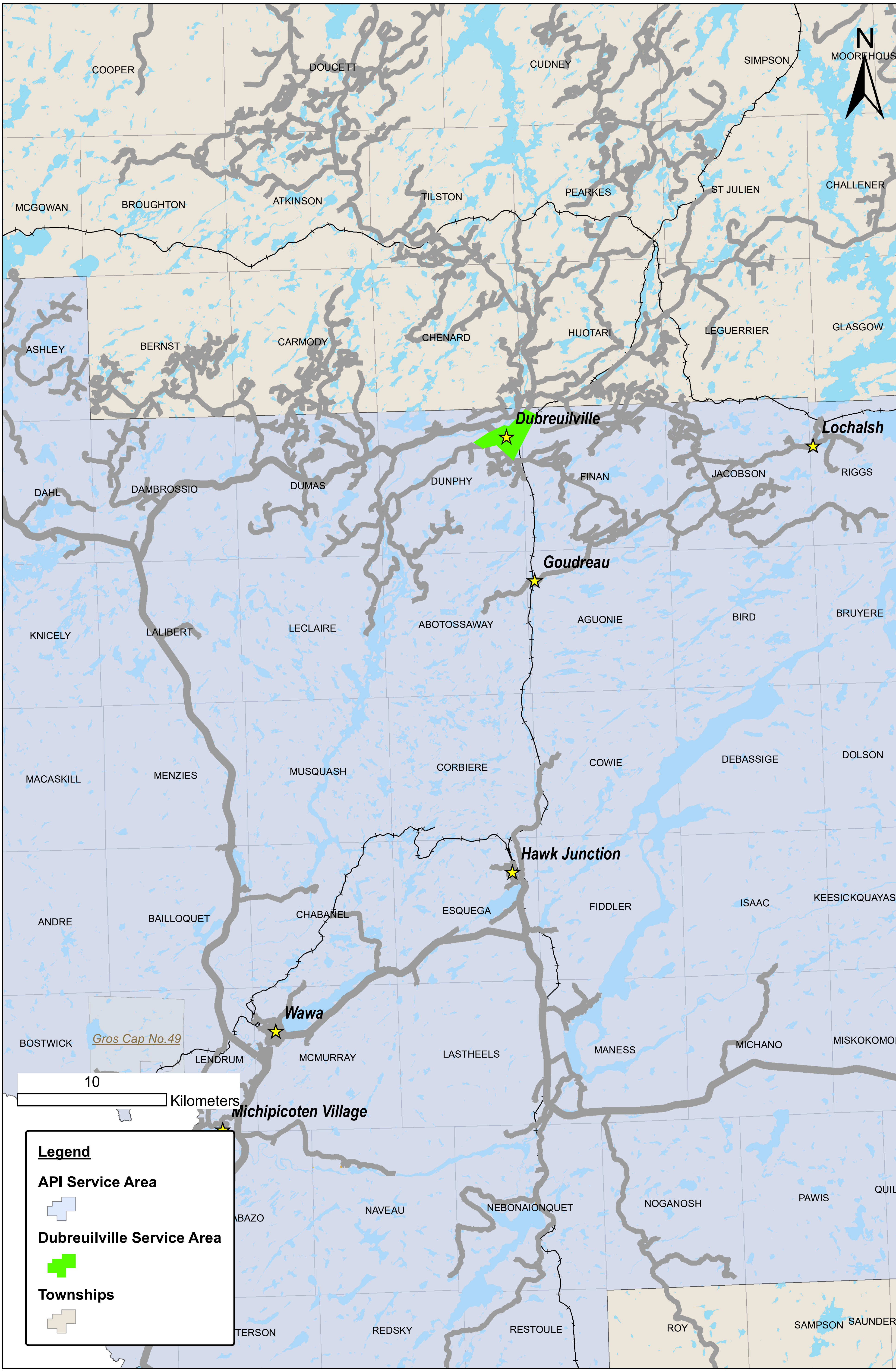
Attachment 1D

Service Area Maps

Algoma Power Inc.
EB-2024-0007



Algoma Power Inc. Service Area
With Dubreuilville



Algoma Power Inc. Service Area
With Dubreuilville - Detail View

Attachment 1E

Completed COS Checklist

Algoma Power Inc.
EB-2024-0007

2024 Cost of Service Checklist

Algoma Power Inc.

EB-2024-0007

Date:

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
GENERAL REQUIREMENTS		
Ch1, p4	Confidential Information - Practice Direction has been followed	
Ch1, p5	Certification by a senior officer 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 OEB's Rules (and the Practice Direction, as applicable).	Att 1C
Ch1, p5	Certification by a senior officer that the evidence filed (including the models and appendices) is accurate, consistent and complete to the best of their knowledge	Att 1C
Ch1, p5	Certification by the Chief Executive Officer, or Chief Financial Officer, or equivalent, that the distributor 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	Att 1C
Ch2, p2	COS checklist filed and statement identifying all deviations from Filing Requirements	(this checklist)
2 & 3	Chapter 2 appendices in live Excel format; PDF and Excel copy of current tariff sheet	Ch 2 filed; Current Att 8A
3	If distributor updates/amends an OEB model, reference made in corresponding exhibit re: what was amended	Listing provided to OEB Staff
3	Regulated entity shown seperately from parent company or any other affiliates	E1; Business Plan
3 & 4	If applicable, if cost of service filed earlier than scheduled, justify why an early rebasing is required by demonstrating why and how distributor cannot adequately manage resources and financial needs during IRM period	N/A
4	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year	N/A
4 & 5	All of the following exhibits filed: Application Overview and Administrative Documents, Rate Base and Capital (including DSP), Customer and Load Forecast, Operating Expenses, Cost of Capital and Capital Structure, Revenue Requirement and Revenue Deficiency/Sufficiency, Cost Allocation, Rate Design, Deferral and Variance Accounts	Confirmed
5	General requirements applicable throughout application: -written evidence included before data schedules -avg. of opening and closing fiscal year balances used for items in rate base (unless alternative method justified) -debt + equity = total rate base -data for test year, bridge year, three most recent historicals (or as many needed to provide actuals back to last OEB-approved), most recent OEB-approved test	Confirmed
5	Documents must include page numbers and be provided in text searchable and bookmarked PDF format	Confirmed
6	Links within Excel models are broken and models named so that they can be identified (e.g. RRWF instead of Attachment A)	Confirmed
7	Materiality threshold: Explanation/justification and/or supporting evidence for material amounts pertaining to CAPEX, capital variances, rate base variances, OM&A, and DVAs; additional details below the threshold if necessary	Confirmed
EXHIBIT 1 - APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS		
Table of Contents		
7	Table of Contents listing major sections and subsections of the application	1.2
Application Summary and Business Plan		
7	Distributor with less than 30k customers: Business and/or Strategic Plan. If no Business or Strategic plan: key planning assumptions, description of material factors (internal and external) that may affect the operation of the utility and major goals of the distributor in the test year and remaining years of the five-year term. Distributor with 30k or more customers: Business Plan underpinning application - can be augmented by plain language summary of distributor's goals that informed the application if this is not otherwise in the Business Plan. Also provide Strategic Plan, if available.	Business Plan is Attachment 1#
8 & 9	Brief, plain language summary of the application which includes the main requests with section references and rationale behind each request. Must include: -Revenue requirement (service revenue requirement requested for test year, increase/decrease ($ and %) from most recent approved, main drivers of revenue requirement changes -Load forecast summary (load and customer growth (% change in kWh, kW and change in customer #s from last OEB-approved)) -Rate base and DSP (major drivers of DSP and cost trends, rate base requested, change in rate base from last OEB-approved ($ and %), CAPEX for test year, change in CAPEX from last OEB-approved ($ and %) -OM&A (OM&A requested for test and change from last OEB-approved ($ and %), drivers and cost trends) -Cost of capital (table showing proposed capital structure and parameters resulting in WACC, statement confirming use of OEB's cost of capital parameters, summary of deviations from OEB methodology) -Cost allocation and rate design (proposed new customer classes and/or customer definition changes, new proposed charges, significant changes proposed to rev. cost ratios and fixed/variable split, mitigation plans) -DVAs (total disposition ($) including split between customer classes and between RPP and non-RPP (if applicable), disposition period(s), new DVAs and requested discontinuation of DVAs) -Bill Impacts ($ and %) for residential customer at 750kWh, and typical customers for all other classes (based on commodity rates on TOU with regulatory charges held constant; bill impacts to be used for Notice (Sub-total A) for residential customer at 750kWh and GS<50 at 2000kWh as well as a typical consumer for a distributor's service area for all customer classes, and bill impacts based on alternative consumption profiles and customer groups as appropriate	1.5
Administration		
9	Primary contact information (name, address, phone, email)	1.3.1
9	Identification of legal (or other) representation	1.3.1
9	Applicant's internet address for viewing of application and any social media accounts, with addresses, used by the applicant to communicate with customers	1.3.2
9	Statement identifying where notice should be published and why	1.3.3

2024 Cost of Service Checklist

Algoma Power Inc.

EB-2024-0007

Date:

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
9	Form of hearing requested and why	1.3.10
9	Requested effective date	1.3.4
10	Statement identifying and describing any changes to methodologies used vs previous applications	1.3.12
10	Identification of OEB directions from any previous OEB Decisions and/or Orders, including commitments made as part of approved settlements. Indication of how these are being addressed in the current application	1.3.13
10	Reference to Conditions of Service - provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application and/or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	1.3.14
10	Description of the corporate and utility organizational structure showing the main units and executive and senior management positions within the distributor; corporate entities relationship chart, showing the extent to which the parent company is represented on the distributor company's Board of Directors; description of the reporting relationships between distributor and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	1.3.17
10	List of approvals requested (and relevant section of legislation). All approvals including accounting orders, new rate classes, revised specific service charges or retail service charges which the distributor is seeking, must be documented - Appendix 2-A provided, but not required to be used by LDC	1.3.4
Distribution System Overview		
10	Description of Service Area - general description and map showing where distributor operates and communities served	1.4/1.4.1
Customer Engagement		
11	Provide information regarding its customer engagement activities, activities that occur on an on-going basis, and specific activities pertaining to application. **May** use Appendix 2-AC to assist in listing customer engagement activities	1.7
11	Ongoing Customer Engagement - Describe methods used to communicate and engage with each customer class regularly, summarize pertinent feedback received through regular customer communications, and explain how feedback informs operations and rate application, where applicable	1.7.1
11 & 12	Application-Specific Customer Engagement - Explain customer engagement process specific to application (tailor customer engagement activities to distributor's circumstances and the proposals in application). Demonstrate how customer needs and priorities were factored into the decision-making process	1.7.1
12	Customer engagement with customers who would be affected by proposals related to new rate classes, changes in to existing rate classes and change in charges such as RSCs, Specific Service Charges, standby rates, and unmetered-load customers	1.7.1
12	All responses to matters raised in letters of comment filed on public record	1.8
Performance Measurement		
12	Link to most recent scorecard	1.9.1
12	Identification of performance improvement targets	1.9.4
12	PEG Model for the test year showing efficiency assessment, discussion on how the results obtained from the PEG model has informed the distributor's business plan and application	1.9.2/ Excel Doc Filed.
12 & 13	Distributors **may** wish to provide table showing respective OEB-approved IRM increases for each of the last historical years from last rebasing, and assigned cohort as per PEG model	1.9.2
13	Activity and Performance-based Benchmarking (APB) results - at least provide the following unit cost variance analysis: - Year-over-year Historical Actuals (for most recent APB results) - Forecast Bridge Year vs Historical Actuals, to extent possible - Test Year vs Historical Actuals, to extent possible	1.9.3
13	Explain variances in cost performance, whether changes in unit costs are within distributor's control, and discuss relevant actions planned or underway. Discuss econometric results to extent possible	1.9.3
Facilitating Innovation		
13 & 14	Distributors are encouraged to include a description of the ways their approach to innovation has shaped the application. Could include explanations of approach to innovation or keeping up with innovation in their business more generally; of specific projects or technologies for enhancing the provision of distribution services; and of enabling characteristics or constraints in their ability to undertake innovative solutions. Explain how innovative alternatives have been considered in place of traditional investments	1.11.1
14	Explain how innovative alternatives have been considered in place of traditional investments. Include information about the costs, expected benefits and associated risks of innovative alternatives	1.11.1
Financial Information		
14	Audited Financial Statements (excluding operations of affiliated companies that are not rate regulated) for two most recent historical years (i.e. one year's statements must be filed, covering two years of historical actuals); if most recent finals n/a, draft financial statements filed and finals, along with summary of main changes if there are any, provided as soon as they are available. Alternatively, if distributor publishes financial statement on its website, a link may be provided	1.1
15	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable. If an Annual Information Form is filed publicly, a link should be provided	1.10.3 (NA)
15	Rating Agency Reports, if available; Prospectuses, information circulars etc. for recent and planned public debt and/or equity offerings	1.10.4
15	Any change in tax status	1.3.15

2024 Cost of Service Checklist

Algoma Power Inc.

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
15	Description of existing accounting orders and departures from these orders, as well as any departures from the USoA	1.3.15
15	Accounting Standards used for financial statements and when adopted	1.3.15
15	If distributor conducting non-distribution businesses, confirmation that accounting treatment used has segregated these activities from rate regulated activities	1.3.15
Distributor Consolidation		
15	Information filed on the extent to which the distributor has investigated opportunities for consolidation or collaboration/partnerships with other distributors (contained within a dedicated section of the application); conclusions from investigations, including future plans	1.12.1
15	If distributor has become party to a proposed or approved MAADs transaction since last rebasing, disclosure of this information in current application	1.12.1
A distributor filing an application to rebase following a consolidation must:		
15	Identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement - list the exhibits in which incentives are discussed	N/A
16	Specify whether and which commitments made to shareholders are to be funded through rates	N/A
16	Detail of realized and projected savings as a result of consolidation compared to what was in the approved consolidation application and explanation of the nature of these savings (e.g. one-time, ongoing etc.)	N/A
16	Detail of efficacy of any rate plan confirmed as part of MAADs	
16	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base	Exhibit 2- not related to MAADs
Impacts of COVID-19 Pandemic		
16	Distributors generally expected to reflect the impacts of the COVID-19 pandemic in their applications, including applicable forecast information. This includes, but is not limited to, the distributor's load forecast, capital forecast, and OM&A forecast in the applicable sections of the application	1.13
EXHIBIT 2 - RATE BASE AND CAPITAL		
Rate Base		
16	Indication of whether capital expenditures are equivalent to in-service additions, and if so, variance explanations only required once. If not, specify whether variance explanations are on CAPEX or in-service additions basis	2.1.1
16	For rate base, opening and closing balances for each year, and the average of the opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance	2.1.2/ Table 2
16	Table showing components of the last OEB-approved rate base, the proposed test year rate base and the variances	2.1.3/Table 3
Fixed Asset Continuity Schedule		
17	Completed Appendix 2-BA for each year - in Excel format	Ch. 2 Appendix
17	Continuity statements and year-over-year variance analysis must be provided (year end balance, including capitalized interest during construction and overhead costs). Explanations provided where there is a year-over-year variance greater than the applicable materiality threshold If applicable, explanation for any restatement (e.g. due to change in accounting standards) and reconciliation to original statements Year over year variance analysis; explanation where variance greater than materiality threshold. The following comparisons must be provided: Hist. OEB-Approved vs Hist. Actual (for the most recent historical OEB-approved year) Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) Hist. Act. vs. Bridge Bridge vs. Test	continuity statements: 2.1.4 YOY analysis back to BA:2.1.3 Capitalized Interest:2.1.4 Overhead Costs:2.5.2 Restatement& reconciliation:2.1.4
17	Opening and closing balances of gross assets and accumulated depreciation correspond to fixed asset continuity statements. If not, an explanation and reconciliation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	2.1.4
17 & 18	Distributor may include in-service balances previously recorded in DVAs, such as renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, and if disposition is being requested in this application. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation	2.1.4 2.4.5 shows Assets and A/D added in 2025 opening. 2-BA shows actual in-service timing.
18	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	2.4.5
18	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	2.1.4
18	All asset disposals clearly identified in Chapter 2 Appendices for all historical, bridge and test years	2.1.4
Depreciation, Amortization and Depletion		
18	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	2.2.2
18	Depreciation, amortization and depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	2.2.2
18	Identification of any Asset Retirement Obligations and associated depreciation or accretion expense - includes the basis for and calculation of these amounts	2.2.1- no AROs
19	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	2.2.1
19	Copy of depreciation/amortization policy if available. If not, equivalent written description; summary of changes to depreciation/amortization policy since last CoS	2.2.1/2.2.2
19	If filing under MIFRS, explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	2.2.2

2024 Cost of Service Checklist

Algoma Power Inc.

EB-2024-0007

Date:

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
19	If no changes have been made to depreciation policy or service lives since last rebasing, a statement confirming that this is the case is required. For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA and reconcile this list to the USoA, detail differences in asset service lives and the TULs from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB if there have been changes in asset service lives since last rebasing	2.2.2
Allowance for Working Capital		
19 & 20	Working Capital - 7.5% allowance or Lead/Lag Study. If previously ordered by OEB as part of last rate application to file Lead/Lag Study, must comply.	2.4.2
20	If Lead/Lag Study conducted - leads and lags measured in days, dollar-weighted and reflects the distributor's actual billing and settlement processing timelines and considers relevant changes to operating environment	N/A
20	Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price. Calculation must include the impact of the most up to date Ontario Electricity Rebate. Distributors must complete Appendix 2-Z - Commodity Expense.	2.4.3
20	Use most recent approved UTRs, Smart Metering Entity Charge and regulatory charges	2.4.1
Distribution System Plan		
20	DSP filed as a stand-alone, self-sufficient element within Exhibit 2	Att 2A
Policy Options for the Funding of Capital		
21	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP) - provide information on need and prudence	No future ACMs proposed 2.5.4
21	Identification that distributor is proposing ACM treatment for these future projects and provide the preliminary cost information, and ACM/ICM materiality threshold calculations - ACM Report provides further details on information required	No future ACMs proposed 2.5.4
21	Complete Capital Module Applicable to ACM and ICM	No future ACMs proposed 2.5.4
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		
22	Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base (i.e. PP&E and associated depreciation). Comparison of actual capital spending with OEB-approved amount and explanation for variances	2.5.5-2.5.7
22	Balances in Account 1508 sub-accounts; rate of interest prescribed by the OEB for DVAs for the respective quarterly period as published on the OEB's website	E9, Tables 9-10, 9-12
22	True-up calculation if material, comparing the recalculated revenue requirement based on actual capital spending relating to the OEB-approved ACM/ICM project(s) to the rate rider revenues collected in the same period; assumptions used in the calculation noted (e.g., half-year rule).	2.5.5-2.5.7
23	Accelerated capital cost allowance (CCA) should not be reflected in the ACM/ICM revenue requirement associated with these projects. Distributors should include the impact of the CCA rule change associated with the ACM/ICM project(s) in Account 1592 - PILs and Tax Variances – CCA Changes sub-account for CCA changes	Exhibit 9, Section 9.3.12. Tables 9-10, 9-12
Capitalization		
24	Capitalization Policy: provide policy including changes since last rebasing application. Confirm if no changes made to capitalization policy since last rebasing application.	2.5.2
24	Overhead Costs: complete Appendix 2-D	2.5.2
24	Burden Rates: identification of burden rates; if burden rates were changed since last rebasing, identification of the burden rates prior to the change	2.5.2
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities		
24	See Appendix A	
General & Administrative Matters		
Ch5, p2	Use of terminology and formats set out in Ch. 5	(throughout DSP)
Investment Categories		(throughout DSP)
Ch5, pp 2, 3 & 4	Investment projects and programs grouped into one of four investment categories (i.e. system access, system renewal, system service, general plant)	Not Applicable- consistent secion headings used.
Distribution System Plan		
Ch5, p4	If a distributor's application uses alternative section headings and/or arranges the information in a different order, table provided that cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in Ch. 5	Consistent Section headings have been used in DSP.
Ch5, p5	DSP duration minimum of 10 years, comprising of a historical and forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of a distributor's last cost or service application to the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year of the current cost of service application..	completed- throughout DSP
Distribution System Plan Overview		
Ch5, p5	High-level overview of information filed in DSP which includes capital investment highlights and changes since last DSP; objectives distributor plans to achieve through DSP, which will be used as a baseline comparison in the performance measurement section below.	5.2.1.1
Coordinated Planning with Third Parties		
Ch5, p5	The distributor must demonstrate that it has coordinated planning with third parties where appropriate. Explanation of whether consultations affected distributor's DSP, and if so, how; for consultations that affected DSP - overview of consultation and relevant material supporting the effects the consultation had on the DSP.	5.2.2.1
Ch5, p5	Overview of consultation should include: purpose, outcome, whether the distributor initiated the consultation or was invited to participate in it, and the other participants in the consultation process	each section of 5.2.2.1

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Ch5, p5	A distributor should file the most recent regional plan. In the absence of a regional plan, the distributor should file a Regional Planning Status Letter from the transmitter.	Attachment I includes most recent RIP, so no Status Letter is required.
Ch5, p5 & 6	Identification of any inconsistencies between DSP and any current Regional Plan. If there are any inconsistencies, explanation of the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan	5.2.2.2
Ch5, p6 & OEB Letter, Jan. 11, 2022	Telecommunications Entities: See January 11, 2022 letter for further guidance to the regulation that requires distributors to consult with any telecommunications entity that operates within its service area when preparing a capital plan for submission to the OEB, for the purpose of facilitating the provision of telecommunications services, and include the following information in its capital plan: -number of consultations conducted and a summary of the manner in which the distributor determined with whom to consult; a summary of the results of the consultation; and a statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how.	5.2.2.1.2
Ch5, p6	REG: -confirmation if there are REG investments in region -if there REG investments proposed in DSP, demonstration of coordination with IESO, other distributors/transmitters (as applicable), and that investments proposed are consistent with Regional Infrastructure Plan - IESO letter in relation to REG investments	•no REG investments planned- 5.2.2.3 •no coordination expected- N/A •IESO letter has been requested per 5.2.2.3; no response received
Performance Measurement for Continuous Improvement		
Ch5, p6 & 7	Distribution System Plan: Summary of objectives for continuous improvement set out in last DSP and discussion on whether these objectives achieved. For objectives not achieved, explanation of how this affects current DSP and if applicable, improvements implemented to achieve the objectives in Section 5.2.1.	s 5.2.3
Ch5, p7	Service Quality and Reliability: -5 historical years of SQRs; explanations for material changes in service quality and reliability and whether and how DSP addresses these issues -for reliability, any declining 5 year SAIDI/SAIFI trends explained -if reliability targets established in last DSP, any under-performance explained	5.2.3.1.1-Service Quality- targets consistently met , no decrease in performance. 5.2.3.2.2 - measures consistently met target
Ch5, p7	Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	Table 2.7
Ch5, p7	Summary of performance for historical period using methods and measures (metrics/targets) identified and how performance has trended over the period. Summary must include historical period data on: -all interruptions -all interruptions excluding loss of supply -all interruptions excluding major events and loss of supply for: SAIFI, SAIDI	Table 2.10
Ch5, p7	Summary of major events that occurred since last cost of service	5.2.3.2.2 Table 2.12
Ch5, p7 & 8	For each cause of interruption for last five historical years: number of interruptions that occurred as a result of the cause of interruption, number of customer interruptions that occurred as a result of interruption, number of customer-hours of interruptions that occurred as a result of the cause of interruption	#outages: Table 2.13 Customer Interruptions : Table 2.14 Customer Hours of Interruption : table 2.15
Ch5, p8	Distributor Specific Reliability Targets: -if establishing performance expectations based on something other than historical performance, evidence provided of capital and operational plan and other factors that justify the reliability performance the distributors plan to deliver -summary of any feedback from customers regarding reliability on distributors' system -distributors that use SAIDI and SAIFI performance benchmarks that are different than the historical average - evidence provided to support reasonableness of benchmarks	5.2.3.2.3
Planning Process		5.3.1
Ch5, p8	Overview of planning process that has informed five-year capital expenditure plan; flowchart accompanied by explanatory text **may** be helpful	5.3.1.3
Ch5, p8	Summary of important changes in distributor's AM process since last DSP	5.3.1.2
Ch5, p9	Process: -provide processes used to identify, select, prioritize (including reprioritization over 5 year term), optimize, and pace execution of investments -demonstration that distributor has considered correlation between plan and customer's feedback and needs -demonstration that distributor has considered potential risks of proceeding/not proceeding with individual capital expenditures -demonstrate how it does grid optimization using an approach that considers the distributor's whole system -consideration, where applicable, of assessing the use of non-wires alternatives, distributed energy resources, cost-effective implementation of distribution improvements affecting reliability, and meeting customer needs as acceptable costs to customers, other innovative technologies, and consideration of dx funded CDM activities	5.3.1.3 -figure 3.1 and associated discussion -section 5.3.1.1 and 5.3.1.1.1 -5.3.1.3 -5.3.1.6 -5.3.1.5, 5.3.1.4
Ch5, p9	Data -identification, description and summary of data used in processes above to identify, select, prioritize, optimize and pace investments over DSP	5.3.1.4-5.3.1.9
Overview of Assets Managed		

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Ch5, p10	Overview of service area (e.g. system configuration, urban/rural etc.) to support capital expenditures over forecast period; asset information (e.g. capacity, utilization, condition, failures/performance, asset risks, demographics) by major asset type that may help explain the specific need for the capital expenditure and demonstration of consideration of economic alternatives	5.3.2.1
Ch5, p10	Statement as to whether distributor has had any transmission or high voltage assets deemed previously by the OEB as distribution assets, and whether there are any such assets that the distributor is asking the OEB to deem as distribution assets in the current application	5.3.2.1
Ch5, p10	Description of whether distributor is a host and/or embedded distributor; identification of any embedded and/or host distributors; partially embedded status identified (including % of total load supplied through host); if host distributor, identification of whether there is a separate embedded class or if any embedded distributors are included in other classes	5.3.2.2
Asset Lifestyle Optimization Policies and Practices		5.3.3.1 (incl. DSC reference)
Ch5, p11	Demonstration that distributor has carried out cost-effective system O&M activities to sustain as asset to the end of its service life (and can include references to the Distribution System Code)	
Ch5, p11	Explanation of processes and tools used to forecast, prioritize and optimize system renewal spending and how distributor intends to operate within budget envelopes	5.3.3.2
Ch5, p11	Demonstration of consideration of potential risks of proceeding/not proceeding with individual capital expenditures	throughout DSP
Ch5, p11	Demonstration that the distributor has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints	throughout DSP
Ch5, p11	Summary of important changes to the distributor's asset life optimization policies, processes, and tools since last DSP	5.2.1.1
System Capability Assessment for REG and DER		
Ch5, p11	Provide list of restricted feeders by name, the feeder designation, the reason for the restriction, number of connected customers, and explain if there are plans to improve the distribution system's ability to connect distributed energy resources	5.3.4.4
Ch5, p11	If a distributor has incurred or expects to incur costs to accommodate and connect renewable generation facilities that will be the responsibility of the distributor under the DSC, refer to Appendix A	5.3.4.2
CDM Activities to Address System Needs		
Ch5, p12	Description of how distributor has taken CDM into consideration in its planning process	5.3.4.6
Ch5, p12	Any application for CDM funding to address system needs must include a consideration of the projected effects on the distribution system on a long-term basis and the forecast expenditures.	5.3.4.6
Ch5, p12	Explanation of proposed activity in the context of the DSP, including providing details on the system need that is being addressed, infrastructure investments that are being avoided or deferred as a result of CDM activity, and the prioritization of proposed CDM activity relative to other system investments in the DSP	5.3.4.6
Ch5, p12	Description of the approach to assessing the benefits and costs of CDM activity	5.3.4.6
Capital Expenditure Summary		5.4.1.1
Ch5, p13	Provide capital expenditure plan that sets out proposed expenditures on distribution system and general plant over a five-year planning period, including investment and asset-related operating and maintenance expenditures	table 4.10,4.11,4.12,4.13
Ch5, p13	Provide a snapshot of a distributor's capital expenditures over a 10-year period, including five historical years and five forecast years	5.4.1.1
Ch5, p13	The entire cost of individual projects or programs allocated to one of the four investment categories based on the primary driver of the investment	5.4.1.1
Ch5, p13	Completed Appendices 2-AA and 2-AB	5.4.1.1
Ch5, p13	Analysis of distributor's capital expenditure performance for the DSPs historical period - should include explanation of variances by investment or category, including actuals v. OEB-approved/planned amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP - explanation of variances between planned and actual volume of work completed and explanation of variances in a given year that are much higher or lower than the historical trend	5.4.1.1
Ch5, p13	Analysis of distributor's capital expenditure performance for the DSPs forecast period; for investments that have a lifecycle >1yr, the proposed accounting treatment, including the treatment of the cost of funds for CWIP	5.4.1.2
Ch5, p14	Analysis of capital expenditures in DSP forecast period v. historical	5.4.2.2
Ch5, p14	Summary of any important modifications to typical capital programs since the last DSP	5.4.1.5
Ch5, p14	Description of the impacts of capital expenditures on O&M for each year or statement that the capital plans did not impact O&M costs	5.4.2.3
Ch5, p14	Statement that there are no expenditures for non-distribution activities in the applicant's budget	5.4.1.4
Justifying Capital Expenditures		
Ch5, p14	Context on how overall capital expenditures over 5 years will achieve distributor's objectives; comment on lumpy investment years and rate impacts of capital investments in long term	5.4
Material Investments		
For each project that meets materiality threshold set in Ch 2A or deemed by applicant to be distinct for any other reason, guidelines are:		
Ch5, p15	General information on the project/program - Need, scope, volume of work expected to be completed, key project timings (incl. key factors that affect timing), total expenditures (inc. contributions and economic evaluation as per DSC, as applicable), comparative historical expenditures, priority, alternatives considered, cost/benefit of recommended alternative, description of the innovative nature of investment if applicable. -Where an investment within the five year forecast period involves a Leave to Construct approval, provide summary of the evidence (as available), for that investment consistent with Chapter 4 of the filing requirements	5.4.2.4

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Ch5, p15	Evaluation criteria and information requirements for each project/program - Demonstration of need, and may include the need to address safety, cyber security, grid innovation, environmental, statutory/regulatory obligations - Where investment substantially exceeds materiality - business case justifying expenditure, alternatives (including CDM activities if applicable), benefits for customers, impact on distributor costs -If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines	5.4.2.4
Ch5, p16	Explanation of how innovative project is expected to benefit customers, such as improved reliability, enhanced customer services, CDM, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate	5.4.2.4
Appendix A (if applicable)		
Ch5, Appendix A	Information on the capability of distribution system to accommodate REG investments, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity	N/A- API does not expect REG investments
Ch5, Appendix A	In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable), includes: applications from renewable generators > 10 kW, number and MW of REG connections for forecast period, information from IESO and any other information about the potential for renewable generation in distributor's service area, capacity of Dx to connect REG, connection constraints	N/A- API does not expect REG investments
EXHIBIT 3 - CUSTOMER AND LOAD FORECAST		
Load Forecasts		
24	Weather normal load forecast provided	3.1.2
24	Table outlining any factors that influence the load forecast in distributor's service territory (e.g. demographics, customer composition etc.)	
24	Explanation of the causes, assumptions and adjustments for the volume forecast, including all economic assumptions and data sources used (e.g. housing outlook & forecasts, other variables used in forecasting volumes)	3.1.3/3.1.4/3.1.6/
25	Explanation of weather normalization methodology	3.1.3
25	Completed Appendix 2-IB; the customer and load forecast for the test year entered on RRWF, Tab 10	Table 17;
25 & 26	Multivariate Regression Model 1.rationale to support change if the proposed model's methodology differs from the methodology used in the most recent load forecast; discussion of modelling approaches considered and alternative models tested 2. Statistics should include, but not limited to, the regression equations coefficients and intercepts (e.g. t-stats, model statistics including R2, adjusted R2, F-stat, root-mean-squared-error and Durbin-Watson statistic), including explanation for any resulting non-intuitive relationships 3. explanation of weather normalization methodology (including if monthly HDD and/or CDD are used they are based on either: 10 year avg. or proposed alternative approach with supporting evidence 4. definitions of HDD and CDD including: climatological measurement points and why appropriate as well as identification of base degrees 5. sources of data for endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable data used and source. Where a distributor has constructed the demand variable to model billed consumption on a class-specific basis, a full explanation of the approach used to pro-rate or interpolate non-interval data (i.e. if billing data are not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation of why the constructed demand series is suitable for modelling 6. any binary variables used must be explained and justified - the use of binary variables should be limited and overlap with other variables should be avoided 7. explanation of any specific adjustments made (e.g. to adjust for loss or gain of major customers or load, significant re-classifications of customers, etc.). Note locally purchased generation should be included in the total for purchased power 8. description of how CDM impacts and other exogenous factors have been accounted for in the historical period, and how CDM impacts, including any CDM targets or forecasts in the bridge and test years, are factored into the test year load forecast 9. data and regression model and statistics used in customer and load forecast in Excel format	1: 3.1.1 2:Table 5 3:3.1.6 4:3.1.6 5:3.1.6 6:3.1.6 7:3.1.8 8:3.2 9: Attachment 3-A
26	NAC Model -rationale to support NAC methodology if the model use differs from the method used in the most recent load forecast -data supporting calculation of NAC values for each rate class -description of how CDM impacts and other exogenous factors have been accounted for in historical period and how CDM impacts, including any CDM targets or forecasts in the bridge and test years, are factored into test year forecast -discussion of weather normalization assumptions used	NA
Incorporating CDM Impacts in the Load Forecast for Distributors		
27	Distributor may request approval for the use of the LRAMVA for a new CDM activity (a distribution-rate funded CDM activity or the Local Initiatives Program (LIP)), which would require establishing an LRAMVA threshold. If a distributor does request to establish an LRAMVA threshold, documentation of the CDM savings to be used as the basis for the 2023 LRAMVA threshold, and description of how these savings are aligned with the 2023 load forecast	3.2-N/A
28	If a distributor proposes a different savings values for a CDM activity in the load forecast and LRAMVA threshold, description of rationale for these differences (e.g., timing of CDM activity, line loss factor, net-to-gross conversion factor)	3.2-N/A

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Accuracy of Load Forecast and Variance Analyses		
28	Completed Appendix 2-IB (2-IA provides further instructions for filling out 2-IB)	Table 17
28	For customer/connection counts: -identification as to whether customer/connection count is shown in year end or average format -year-over-year variances in changes of customer/connection counts with explanation for changes in the definition of, or major changes made in the composition of each customer class -explanations of bridge and test year forecasts by rate class -for last rebasing, variance analysis between last OEB-approved and actuals with explanations for material differences	3.3.2
28	For consumption and demand: -explanation and details to support how kWh are converted to kW for applicable demand-billed classes -year-over-year variances in consumption (kWh) and demand (kW or kVA - the latter for demand billed rate classes) by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (comparison done for both historical actuals against each other and historical weather-normalized actuals over time) -explanations of the bridge and test year forecasts by rate class (and how these vary from or are trending from both historical actuals and from weather-normalized actuals) -for last rebasing variance analysis between the last OEB-approved and the actual results with explanations for material differences	3.3.3
29	All data and equations used to determine customers/connections, demand and load forecasts provided in Excel format	Attachment 3-A
EXHIBIT 4 - OPERATING EXPENSES		
Overview		
29	Brief explanation (quantitative and qualitative) of test year OM&A levels, how the distributor develops and receives approval of their OM&A budget, cost drivers and significant changes relative to historical and bridge years, trends in costs and relevant metrics including OM&A per customer (and its components) for the historical, bridge and test years, inflation rate assumed (if proposing different rate than IPI - provide explanation supporting proposal), business environment changes	4.1.1
OM&A Summary and Cost Driver Tables		
Inclusion of the following tables in evidence and all OM&A appendices filed:		
29	Summary of recoverable OM&A expenses; Appendix 2-JA	Table 2
29	Recoverable OM&A cost drivers; Appendix 2-JB	Table 6
29	OM&A programs table - Appendix 2-JC **or** OM&A by USoA Table - Appendix 2-JD	Table 8
29	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Table 4
29 & 30	Distributors with 30k or more customers: present OM&A by program; Appendix 2-JC filed to provide OM&A details and variance analysis on a program basis. For each program, provide a definition of the USoA accounts included	N/A
30	Only distributors with less than 30k customers: option to file OM&A by program or USoA. If USoA chosen, 2-JD filed instead of 2-JC	Table 8- 2 JC
30	For all distributors, the table provided (2-JC or 2-JD) must reflect the entire OM&A amount proposed to be recovered through rates. Information provided for bridge and test years.	Table 8
30	Appendix 2-JB populated to provide information on the cost drivers of OM&A expenses; 2-JA broken down into major categories	Table 6; Table 2
30	Identification of change in OM&A in test year in relation to change in capitalized overhead	4.2.3; Table 8
OM&A Variance Analysis		
30	Re: 2-JC or 2-JD - variance analysis between: -test year vs last OEB approved -historical OEB-approved vs historical actuals (for the most recent historical OEB-approved year) -test year vs bridge year	4.3.2
30	If OM&A expense detailed on USoA basis, variance analysis and explanation broken down by the five major OM&A categories as per 2-JA	N/A- provided by Program
30	For all distributors, the variance analysis includes explanation of whether the change was within the distributor's control or not - distributors encouraged to provide explanations for costs above the threshold which have impacted historical trend	4.3.2
Workforce Planning and Employee Compensation		
31	Completed Appendix 2-K; information on labour and compensation includes total amount, whether expensed or capitalized	Table 9
31	If there are three or fewer employees in any category, aggregate with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees.	N/A
31	Description of proposed workforce plans, including compensation strategy and any changes from previous plan	4.4.1
31	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to FTEs and compensation. Explanation for all years includes: - Variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans - relevant studies (e.g. compensation benchmarking)	4.4.1- previous plans Material Changes: 4.4.2
31	Details of employee benefit programs including pensions, OPEBs, and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital provided for the last OEB-approved rebasing application, and for historical, bridge and test years	4.4.3
31	Most recent actuarial report; tax section of evidence agrees with this analysis	4.4.3

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31	For virtual distributors - Appendix K completed in relation to the employees of the affiliates who are doing the work of the regulated distributor. Provide the status of pension funding and all assumptions used in the analysis	N/A; Appendix K includes affiliate FTE completing work for API.
32	Indication if pension and OPEBs to be recovered using cash or accrual method. If cash method, sufficient supporting rationale and evidence for adopting cash method. If proposing to change the basis in which pension and OPEB costs are included in OM&A from last rebasing, quantification of impact of transition provided	4.4.3
Shared Services and Corporate Cost Allocation		
32	Identification of all shared services among affiliates; identification of the extent to which the applicant is a "virtual utility" and justification of proposed shared services and cost allocation	4.5
32	For shared services among affiliated entities: type of service provided or received, pricing methodology	4.5, appendix 2-N
32	Allocation methodology for corporate services, list of shared services, list of costs and allocators and how the allocator was derived, any third party review of cost allocation methodology	4.5
32	Completed Appendix 2-N for service provided or received for historical actuals, bridge and test; including reconciliation with revenue included in Other Revenue	4.5
32 & 33	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	4.5
33	Identification of any Board of Director costs for affiliates included in LDC costs	4.5
Non-Affiliate Services, One-Time Costs, Regulatory Costs		
33	Purchases of Non-Affiliated Services - copy of procurement policy (including information on signing authority, tendering process, non-affiliate service purchase compliance)	Appendix 4-D
33	For material transactions not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	4.6.1
33	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test year. If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided	4.6.2
33 & 34	Regulatory costs - breakdown of actual and anticipated regulatory costs including OEB cost assessments and expenses related to the CoS application (e.g. legal fees, consultant fees), information supporting incremental level of costs for preparation and review of current application, proposed recovery (i.e. amortized?), explanation if different than 5 years, completed Appendix 2-M	4.6.3
LEAP, Charitable and Political Donations		
34	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes. If proposing LEAP funding higher than 0.12%, details of demographics provided	4.7
34	For any charitable contributions claimed for recovery, detailed information provided	
34	Confirmation that no political contributions have been included for recovery	
Conservation and Demand Management		
35	Statement confirming that no costs for dedicated CDM staff to support IESO programs funded under the 2021-2024 CDM Framework are included in the revenue requirement	4.8.1
35	Distributor should generally not include any forecast costs associated with partnership in the IESO's LIP within its revenue requirement; distributor can seek to recover partnership costs at a future date through the LIP deferral account. If distributor plans to partner with the IESO for the LIP at the time of its cost of service application, description of proposed approach to partnership, including a forecast of LIP costs	4.8.1
Funding Options for Future Conservation and Demand Management Activities		
35	If CDM activities included in COS where CDM activities expected to come into service during Price Cap IR term, identification of if costs of such CDM activities included in the revenue requirement, or if the distributor intends to propose treatment similar to an ACM for these future CDM activities	N/A
35	If the latter as noted above, supporting rationale provided (e.g., the preliminary cost information and ACM/ICM materiality threshold calculations to show that a similar capital project would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application)	N/A
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
Capital Structure		
36	Use of most recent parameters issued by the OEB, subject to update if new parameters available prior to OEB decision. Alternatively - distributor specific cost of capital with supporting evidence and justification	5.2
36	Completed Appendix 2-OA for last OEB approved and test years	5.3
36	Completed Appendix 2-OB for historical, bridge and test years with respect to long-term debt, short-term debt, preference shares, and common equity	5.4
36	Explanation for any material changes in capital structure or material differences between actual and deemed capital structure including: retirement of debt or preference shares and buy-back of common shares; short-term debt, long-term debt, preference shares and common share offerings	5.2.1 and 5.2.2
Cost of Capital (Return on Equity and Cost of Debt)		
The following provided for each year:		
37	Calculation of cost for each capital component	5.2.2
37	Profit or loss on redemption of debt, if applicable	5.2.2
37	Copies of current promissory notes or other debt arrangements with affiliates	N/A
37	Explanation of debt rate for each existing debt instrument including an explanation on how the debt rate was determined and is in compliance with the policies documented in the 2009 Report or applicant's proposed approach	5.2.2
37	Forecast of new debt in bridge and test year - details including estimate of rate and other pertinent information (e.g. affiliated debt or third party?)	5.2.2
37	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	N/A
37	Historical return on equity achieved	Table 3
Not-for-Profit Corporations		

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37	Requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	N/A
38	Statement as to whether the revenues derived from the return on equity component of the cost of capital is to be used to fund reserves or will be used for other purposes	N/A
38	If the revenues derived from the return on equity component will be used to fund reserves, specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied	N/A
38	If the revenues derived from the return on equity component will be used for other purposes, statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities); rationale provided supporting the use of the revenues in this manner. Also, governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities provided	N/A
38	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	N/A
EXHIBIT 6 - REVENUE REQUIREMENT AND REVENUE DEFICIENCY OR SUFFICIENCY		
38	The following information must be provided in this exhibit (with cross references to where in the application further details can be found for each) excluding energy costs and revenues and unregulated costs and revenues: -determination of net income, statement of rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency or sufficiency in revenue, gross deficiency or sufficiency in revenue	6.3.1
38 & 39	Revenue deficiency or sufficiency calculations net of electricity price differentials captured in the Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects) and for which disposition is not being sought in the application.	6.3.1
39	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	6.3.2
39	Impacts of any changes in methodologies on deficiency/sufficiency and on individual cost drivers contributing to it	6.3.3
Revenue Requirement Work Form		Attachment 6A
39	Completed RRWF. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	
39	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	RRWF- adjusted to fit Rate Design
40	For revenues - calculation of bridge year forecast of revenues at existing rates; calculation of test year forecasted revenues at each of existing rates and proposed rates	6.2.1
Income Tax or PILs		
40	Must provide detailed calculations of income tax or PILS. Must include a completed Excel version of the PILs model available on the OEB's website, including derivation of adjustments for historical, bridge and test years. Regulatory assets and liabilities must excluded from PILs calculations when they were created and when they were disposed, regardless of the actual tax treatment accorded those amounts.	6.4.1, Attachment 6B
40	Supporting schedules and calculations identifying reconciling items	6.4.1
40	Most recent federal and provincial tax returns	Attachment 6C
40	Financial Statements included with tax returns if different from those filed with application	N/A 2023 Tax Return (draft) and 2023 FS attached
40	Calculation of tax credits; redact where required (filing of unredacted versions is not required)	6.4.1
41	Supporting schedules, calculations and explanations for other additions and deductions	6.4.1
41	Completion of the integrity checks in the PILs Model	complete- See PILS model.
41	Accelerated CCA - full revenue requirement impact recorded in Account 1592 and the balance sought for review and disposition, method used in calculating the revenue requirement impact recorded in Account 1592, detailed calculations by year for the full revenue requirement impact recorded in Account 1592	6.4.2; see also Exhibit 9
41 & 42	May propose a mechanism to smooth the tax impacts over the five-year IRM term.	6.4.2
Other Taxes		
42	Account 6105 is not an OM&A account and should be excluded from all OM&A totals. Applicant should provide an explanation of how these tax amounts are derived.	6.5
Non-recoverable and Disallowed Expenses		
42	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	6.6
Other Revenue		
42	Completed Appendix 2-H, including the breakdown of each account showing the components of each	Chapter 2 Appendices 2-H
42 & 43	For each other distribution revenue account: -comparison of actual revenues for historical years to forecast revenue for bridge and test year, including explanations for significant variances year-over-year -revenue from any new proposed specific service charges, changes to rates, or new rules for applying existing specific service charges (incl. any credits to customers) -revenue from affiliate transactions, shared services, or corporate cost allocation. For each affiliate transaction identification of service, the nature of service provided, accounts used to record revenue, and costs to provide service -revenue from affiliate transactions recorded in Account 4375 -expenses from affiliate transactions recorded in Account 4380	6.7.2, 6.7.3, 6.7.4
43	Balances recorded in Account 4375 and Account 4380 reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Allocation for the three historical years, the bridge year and the test year. Any differences must be reconciled	N/A
43	Revenue related to microFIT recorded as revenue offset in Account 4235 and not included as part of base revenue requirement	6.7.1
43	Transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business and compliance with article 340 of APH; explanations for any deviations	6.7.4
43	Identification of any discrete customer groups that may be materially impacted by changes to other rates and charges.	N/A
EXHIBIT 7 - COST ALLOCATION		

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Cost Allocation Study Requirements		
44	Completed cost allocation study using the OEB-approved methodology or the distributor's study and model reflecting forecasted test year loads and costs and supported by appropriate explanations and live Excel spreadsheets; sheets 11 and 13 of the RRWF complete	7.4
44	Description of weighting factors, rationale for use of default values (if applicable)	7.2.3
44	If distributor is choosing to use the same weightings as its previous rebasing application, a reference to the previous application provided	N/A-7.3.2
45	Complete live Excel cost allocation model, whether using the OEB-issued one or a different model. If using the OEB-issued model, Input sheet I.2, cells c15 and c17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information.	Att 7A
Load Profiles and Demand Allocators		
45	Update all classes' load profiles and update demand allocators, if class load profiles are unavailable, provide an explanation and commit to putting plans in place to remedy this for next time a cost allocation model is filed	7.2.2
45	Discussion of how load profiles have been normalized for weather and any notable events impacting usage patterns	7.2.2
45	If multivariate regression used, the following provided: -statistics and statistical tests related to regression equation(s) coefficients and intercept -explanation of the weather-normalization methodology including: relationship between demand and Heating and/or Cooling requirements, determination of normal weather: the hourly for daily Heating and/or Cooling required -sources of data used for both endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable, data used and the soruce of the data provided -explanation of any specific adjustments made (e.g. to address gaps in historical meter data)	N/A
46	Data and regression model and statistics used in the weather normalization of load profiles provided in Excel format (includes showing the derivation of any constructed variables)	N/A
46	Demand Allocators: spreadsheet and a description with calculations to show how demand allocators are derived from the historical weather normal or weather actual load profiles	7.2.2/ Att 7B
46	Historical Average: Where the annual demand allocators are based on weather actual load profiles, at least three, and ideally five years of historical data should be used to perform weather normalization. Where the annual demand allocators are based on weather normalized load profiles, fewer years may be used	7.2.2
46 & 47	Host Distributor only - evidence of consultation with embedded Dx - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges levied); include in cost allocation study and RRWF - if embedded Dx billed as GS customer - include with the GS class in cost allocation model and the RRWF. Provide cost of serving, load served, asset ownership information, distribution charges levied, appropriateness of rates for the GS class recovering costs of providing low voltage dx services to embedded distributor(s). Completed Appendix 2-Q - Cost of Serving Embedded Distributors	N/A
47	microFIT - if the applicant believes that it has unique circumstances which would justify a different rate than the generic rate, documentation to support rate must be provided	N/A
48	Standby Rates - distributors should request approval for its standby rates to be made final and provide evidence confirming that they have advised all affected customers of the proposal. A distributor that seeks changes to its standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s).	N/A
48	If new customer class or changing definition of existing classes, rationale and restatement of revenue requirement from previous cost of service	N/A
48	If eliminating or combining customer classes, rationale and restatement of revenue requirement from previous cost of service	N/A
Class Revenue Requirements		
49	To support a proposal to rebalance rates, information on the revenue by class that would apply if all rates were changed by a uniform percentage provided. Ratios compared with the ratios that will result from the rates being proposed by the distributor.	Table 6
Revenue to Cost Ratios		
49 & 50	If R:C ratios outside dead band - cost allocation proposal to bring them within the OEB-approved ranges provided. In making any such adjustments, potential mitigation measures addressed if the impact of the adjustments on the rates of any particular class or classes is significant.	7.4.2
50	If distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided	7.4.2
50	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	N/A- OEB Model used
EXHIBIT 8 - RATE DESIGN		
50	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places; if departing from this approach, explanation provided as to why necessary and appropriate	8.2.5 , 8.2.6
Fixed Variable Proportion		

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50 & 51	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V for each rate class with supporting info -Proposed F/V for each rate class with explanation for any changes from current proportions -Table comparing current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	8.2.6 Table 3, 8.2.8 Table 4,5,
RTSRs		
51	Completed RTSR Model in Excel	Attachment 8C
51	RTSR information consistent with working capital allowance calculation; explanation for any differences	8.3.1
Retail Service Charges		
51	Distributors should note that the current retail service rates and charges were established on a generic basis and should refer to the most recent rate order for the current approved rates.	8.2.5
Regulatory Charges		
52	If applying for a rate other than the generic rate set by the OEB, distributors must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate	8.3.3
Specific Service Charges		
52	If requesting new specific service charge or a change to the level of an existing charge, description of the purpose of charge, or reason for change to an existing charge; calculations to support charges	8.3.6
52	Identification in the Application Summary all proposed changes that will have an impact on customers, including changes to other rates and charges that may affect a discrete group; identification of specific customers or customer groups impacted by each proposal	N/A for SSC
52	Calculation of charge includes: direct labour, labour rate, burden rate, incidental, other	N/A for SSC
53	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions recovered from these rates from last OEB-approved year to most recent actuals and the revenue or capital contributions forecasted for the bridge and test years. A proposal and explanation as to whether these charges should be included on tariff sheet	8.3.6
53	Revenue from SSCs corresponds with Operating Revenue evidence	8.3.6
Wireline Pole Attachment Charge		
53	Under the new regulation (Part VI.1: O. Reg. 842/21, (Electricity Infrastructure (Part VI.1 of the Act)), OEB is to establish a generic, province-wide pole attachement charge for 2022. The Regulation further requires the OEB to set the charge for 2023 and subsequent years by adjusting the prior year's charge for inflation. The Regulation provides that the annual charge will be established by order without a hearing.	8.3.7
Low Voltage Service Rates		
If the distributor is fully or partially embedded, information on the following must be provided:		
54	Forecast LV Cost	8.3.8
54	Actual LV Cost for the last three historical years along with bridge and test year forecasts; year-over-year variances and explanations for substantive changes in costs over time up to and including test year forecast	8.3.8
54	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	8.3.8
54	Allocation of forecasted LV cost to customer classes (typically proportional to Tx connection revenue)	8.3.8
54	Proposed LV rates by customer class	8.3.8
Smart Meter Entity Charge		
55	Current OEB-approved SMC charged until the OEB approved any updated SMC	8.3.9
Loss Factors		8.3.10
55	Proposed SFLF and Total Loss Factor for test year	
55	Statement as to whether LDC is embedded including whether fully or partially	8.3.10
55	Study of losses if required by previous decision	8.3.10
55	3-5 years of historical loss factor data - Completed Appendix 2-R	8.3.10
55	If proposed distribution loss factor >5% or is showing an increasing trend, explanation for level of losses, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward	8.3.10
55	Explanation of SFLF if not standard	8.3.10
55	Reconciliation between the application and RRR filing	8.3.10
Tariff of Rates and Charges		
55	Current and proposed Tariff of Rates and Charges - **must be filed in Excel format and PDF format** Explanation and support of each change in the appropriate section of the application	8.3.11 , Attachment 8A, Attachment 8B
55	Completed Bill Impacts Model	Att 8D- API Bill Impact Model
56	Explanation of changes to terms and conditions of service if changes affect application of rates and rationale behind those changes	N/a
56	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	8.3.3, 8.3.4, 8.3.13
Revenue Reconciliation		

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56	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	8.3.12 Table 13 ,
56	Completed RRWF - Sheet 13 (table reconciling base revenue requirement against revenues recovered through proposed rates)	8.3.12 Table 13, or sheet 13 on the RRWF
Bill Impact Information		
56	Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	8.3.13 table 14
56	Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant	8.3.13/ Att 8D
57	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory for each class	8.3.13/ Att 8D
57	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	8.3.13
Rate Mitigation		
57	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification for mitigation measure including reasons if no mitigation proposed, other relevant information. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	8.3.13, 8.3.14
Rate Harmonization Mitigation Issues		8.3.14
58	If part of a MAADs transaction, and rate harmonization plan not yet approved by the OEB, a rate harmonization plan must be filed	
58	Plan includes a detailed explanation and justification for the implementation plan, and an impact analysis	8.3.14
58	If impact of COS increases and harmonization effects result in total bill increases for any customer class exceeding 10%, discussionion of proposed measures to mitigate increases in its mitigation plan, or justification provided as to why mitigation is not required	8.3.14
58	Migration plan that includes fully harmonizing rates that is to be accomplished over more than one year must be supported by a detailed plan for accomplishing this during the subsequent Price Cap IR period	8.3.14
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
58	Summary table showing all active DVAs not disposed of yet, showing principal and interest/carrying charges, total balance for each account, whether account being proposed for disposition and whether the account is proposed to be continued or discontinued	9.3.1 Table 1
58	In a separate section under the summary table: - For any account identified, provide an explanation as to why it is not being proposed for disposition - For any Group 2 account identified, provide an explanation as to why it is being discontinued	9.3.2
58	If applicable, description of DVAs that were used differently than as described in the APH, relevant accounting order or other OEB document	N/A
58	Completed DVA continuity schedule for period from last disposition to present - live Excel format. Continuity schedule must show separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all active DVAs. The opening principal amounts and interest amounts for Group 1 and 2 balances, shown in the DVA Continuity Schedule, must reconcile with the last applicable approved closing balances.	Att 9A/Live excel attachment
59	Explanation if account balances in continuity schedule differs from trial balance reported through RRR and documented in AFS - included in tab Appendix A of DVA schedule. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the RRR is to be provided in the DVA continuity schedule	Table 9-2/Table 9-3
59	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis - the OEB expects that no adjustment will be made to any deferral and variance account balances previously approved by the OEB on a final basis. If any adjustments have been made, explanation for the nature and the amount of the adjustment(s), and appropriate supporting documentation, under a section titled “Adjustments to Deferral and Variance Accounts”	9.2.1
59	Confirmation of use of interest rates established by the OEB by month or by quarter for each year; most recently published rate used for future periods	9.2.1
Disposition of Deferral and Variance Accounts		
59	Refer to DVA Continuity Schedule Instructions for instructions on completing the DVA Continuity Schedule, annual updates and discussions on default treatments and expectations for DVAs	confirmed
59	Provide confirmation that a distributor is allocating DVAs using an approved allocator. If proposing to allocate a DVA which the OEB has not established an allocator, proposed allocation based on cost driver must be provided with justification; indication of proposed billing determinants, including charge type for recovery purposes and included in cont. schedule	9.3.3
60	Propose rate riders that dispose of the balances. If the distributor is proposing an alternative recovery period other than one year, explanation provided	9.2.1
60	Provide support (e.g., explanations, calculations) on how each material Group 2 balance is determined. For utility-specific Group 2 accounts that are not material, provide a brief explanation of the account balance and the relevant accounting order	9.3.10, 9.3.8
Disposition of Accounts 1588 and 1589		
60	If a distributor has not implemented OEB’s February 21, 2019 accounting guidance, indication that this is the case	9.3.4
60	Indication of the year in which Account 1588 and Account 1589 balances were last approved for disposition, and whether the balances were approved on an interim or final basis. If the balances were last disposed on an interim basis, indicate the year in which balances were last disposed on a final basis	9.3.4
60	If requesting final disposition of balances for the first time following implementation of the accounting guidance, confirmation that accounting guidance has been implemented fully effective January 1, 2019	9.3.4

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60 & 61	In order to request for final disposition of historical balances as part of the current application, confirmation that these balances have been considered in the context of the accounting guidance and provide a summary of the review performed. Discussion on the results of the review, any systemic issues noted, and whether any material adjustments to those balances have been recorded. Summary and description of each adjustment made to the historical balances provided	9.3.4
61	GA Analysis Workform (in live Excel format) for each year that has not previously been approved by the OEB for disposition. If the distributor is adjusting the Account 1589 GA balance that was previously approved on an interim basis, the GA Analysis Workform must be completed from the year after the distributor last received final disposition for Account 1589	Appendix 9-B
61	As described in Note 5 in the GA Analysis Workform, reconciliation of any discrepancy between the actual and expected balance by quantifying differences (e.g. true-ups between estimated and actual costs and/or revenues). Any remaining unexplained discrepancy between the actual and expected balance that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation.	9.3.11, 9.3.12, 9.3.13/GA Analysis Workform/Att 9B
61	Completed reasonability test for the balance in Account 1588. The reasonability test is included in the GA Analysis Workform.	GA Analysis Workform/Att 9B
Disposition of Account 1580, Sub-account CBR Class B Variance		
61	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. Must be disposed over one year. - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance - Refer to DVA Continuity Schedule Instructions for further details on the treatment of CBR related sub-accounts	9.3.5
Disposition of Account 1595		
62	Distributors are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year once, on a final basis	9.3.6
62	Explanation for any material residual balances being proposed for disposition, including quantifying significant drivers of the residual balance	9.3.6
Disposition of Retail Service Charges Related Accounts		
62 & 63	If there is a balance in 1518 or 1548, distributor must: - confirm variances are incremental costs of providing retail services - state whether Article 490 of APH has been followed; explanation if not followed	9.3.7
63	If the balances in Account 1518, Account 1548, or Account 1508 Sub-account Retail Service Charges Incremental Revenue are material, the distributor must identify drivers for the balance(s) and provide schedule identifying all revenues and expenses listed by USoA that are incorporated into the variances	9.3.7
63	The OEB established a new variance account for electricity distributors that no longer used the RCVAs. The balance in the account, as well as in Accounts 1518 and 1548, would be disposed to ratepayers in a future rate application, and the account subsequently closed. Distributors that have not yet done so in a COS application may forecast balances up to the end of the incentive rate-setting period and the OEB may consider disposing of the forecast amounts	9.3.7
Disposition of Account 1592, Sub-account CCA Changes		9.3.8
63 & 64	Calculations for accelerated CCA differences per year, based on actual capital additions. Calculations include: underpreciated capital cost continuity schedules for each year itemized by CCA class, calculated PILs/tax differences, grossed-up PILs/tax differences. other applicable information	9.3.8 Exhibit 6
64	Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable	9.3.8
64	Reconciliation of these amounts to the amounts presented in Account 1592 sub-account CCA changes in the DVA continuity schedule	9.3.8
64	If a distributor does not have a balance in this sub-account, the distributor must explain why	9.3.8
Disposition of Account 1509 Impacts Arising from the COVID-19 Emergency		
64 & 65	If requesting disposition of any amounts related to the COVID-19 Account, the following, at a minimum is to be provided: -Discussion regarding the interactions between the COVID-19 Account and other existing generic or utility-specific accounts, including a determination that there is no double-counting between multiple ratemaking mechanisms -Calculation showing that the distributor passes the ROE-based means tests, including limitations on recoveries when various ROE thresholds are reached, and that the appropriate recovery rates for each sub-account have been applied -Supporting calculations for the annual amounts recorded in each of the sub-accounts, including the methodology used to measure incremental costs and savings, as applicable - Discussion of causation, materiality, prudence of any amounts recorded in the sub-accounts, including all identified savings and cost reductions -Discussion of whether the distributor would be able to reasonably forecast any further entries in the account, up to the effective date of the new rates, so that the account may be disposed in its entirety in the current proceeding (and whether the distributor would be amenable to such an approach) -Statement confirming proposed discontinuation of the COVID-19 Account, effective the same date as the new rates. If this is not the case, supporting rationale provided	9.3.9
Disposition of Account 1508, Sub-account Pole Attachment Revenue Variance		
65	A table showing the calculation of the account balance, the annual balance broken down customer type, if applicable and: -the number of poles used in the calculation -the pole attachment charge incorporated in rates -the updated charge May also foecast the balance to the effective date of its new rates	9.3.10
Disposition of Distributor-Specific Accounts		
66	For any material, distributor-specific accounts requested for disposition (e.g., Account 1508 sub-accounts), supporting evidence showing how the annual balance is derived and relevant accounting order should be provided. For distributor-specific accounts requested for disposition that are not material, provide a brief explanation for the account balance and the relevant accounting order.	9.3
Establishment of New Deferral and Variance Accounts		
66 & 67	If new DVA - evidence provided which demonstrates that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order with description of the mechanics of the account, provide examples of general journal entries and the proposed account duration	9.4.1

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Lost Revenue Adjustment Mechanism Variance Account		
67	In preparing claims related to disposition of outstanding LRAMVA balances, distributors may seek to claim savings from Conservation First Framework (CFF) programs, and from programs they delivered through the Local Program Fund that was part of the Interim Framework. Distributors should provide sufficient supporting documentation on project savings to support their claim	9.5.1 9.3.12
Disposition of LRAMVA		
68	Disposition sought of all outstanding LRAMVA balances related to previously established LRAMVA thresholds	9.5.1
69	Current version of LRAMVA Work Form (Excel)	9.5.1
An application for lost revenues should include:		
69	Final Verified Annual Reports if claiming lost revenues from savings from CDM programs delivered in 2017 or earlier	9.5.1
69	Participation and Cost reports and detailed project level savings in Excel format made available by the IESO	
69	Other supporting evidence with an explanation and rationale should be provided to justify the eligibility any other savings from a program delivered by a distributor after April 15, 2019	9.5.1
69	Personal information and commercially sensitive information removed, or if required, filed in accordance with OEB's Rules of Practice and Procedure and Practice Direction on Confidential Filings	9.5.1
An application for lost revenues should also provide:		
70	Statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition	9.5.1
70	Statement confirming LRAMVA based on verified savings results supported by the distributors final Verified Annual Reports and Persistence Savings Report (both filed in Excel format)	9.5.1
70	Statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation	9.5.1
70	Summary table with principal and carrying charges by rate class and resulting rate riders	9.5.1
70	Statement confirming recovery period; rationale provided for disposing the balance in the LRAMVA if one or more classes does not generate significant rate riders	9.5.1
70	Details related to the approved CDM forecast savings from the last rebasing application	9.5.1
70	Statement explaining how rate class allocations for actual CDM savings were determined by class and program for each year	9.5.1
70	Statement confirming whether additional documentation was provided in support of projects that were not included in distributors final Verified Annual Reports and Participation and Cost Reports (Tab 8 of LRAMVA Work Form as applicable)	9.5.1
70 & 71	If not already filed in support of a previous LRAMVA application, provide Participation and Cost Reports and detailed project level savings files made available by the IESO and/or other supporting evidence to support the clearance of energy- and/or demand-related LRAMVA balances where final verified results from the IESO are not available - filed in Exel format	9.5.1
71	For a distributor's street lighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: explanation of the methodology to calculate street lighting savings, confirmation whether the street lighting projects received funding from the IESO and the appropriate net-to-gross assumption used to calculate streetlighting savings	9.5.1
For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information:		9.5.1
71	Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application	9.5.1
71	Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed	9.5.1
71	Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings	9.5.1
71	Confirmation that the distributor has received reports from the participating municipality that validate the number and types of bulbs replaced or retrofitted through the IESO program	9.5.1
71	A table, in live Excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade project (including data on number of bulbs, types of bulb replaced or retrofitted, average demand per bulb)	9.5.1
For the recovery of lost revenues related to demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information:		9.5.1
71	The third-party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different than the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate	9.5.1
72	Rationale for net-to-gross assumptions used	9.5.1
72	Breakdown of billed demand and detailed level calculations in live Excel format	9.5.1
For program savings up to December 31, 2022 for projects completed after April 15, 2019, a distributor should provide the following:		9.5.1
72	Related to CFF programs: explanation as to how savings have been estimated based on the available data (i.e., IESO's Participation and Cost Reports) and/or rationale to justify the eligibility of the program savings	9.5.1
72	Related to programs delivered by a distributor through the Local Program Fund under the Interim CDM Framework: explanation and rationale to justify the eligibility of the additional program savings	9.5.1
Continuing Use of the LRAMVA for New CDM Acitivities		
72	Indication of whether distributor is requesting the continued use of the LRAMVA for one or more activities related to distribution rate-funded CDM activities or LIP activities	9.5.1
72	If requesting access to, or use of, the LRAMVA for these activities, demonstration of need for the LRAMVA (or similar mechanism), the proposed LRAMVA threshold, how it intends to support the tracking of lost revenues, and the nature of the documentation that it proposes to provide at the time of LRAMVA disposition	9.5.1

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72	Allocation of the CDM savings for both the LRAMVA and the load forecast provided by customer class and for both kWh and, as applicable to a customer class, kW. Document how CDM savings will be tracked and reported in order to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs	9.5.1
Appendix A Cost of Eligible Investments for the Connection of Qualifying Generation Facilities		
Appendix A	If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09	N/A
Appendix A	Appendices 2-FA through 2-FC identifying all eligible investments for recovery	N/A
Appendix A	For distributors that are already receiving rate protection as a result of a previous application the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for input into Appendices 2-FA through 2-FC. This would generate a new up-to-date rate protection amount for the test year and beyond, which will be subject to the materiality threshold	N/A

Attachment 1F(Filed Separately)

2022 Audited Financial Statements

Algoma Power Inc.
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Attachment 1G(Filed Separately)

2023 Audited Financial Statements

Algoma Power Inc.
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Attachment 1H

API Distribution Licence

Algoma Power Inc.
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Ontario

Electricity Distribution Licence

ED-2009-0072

Algoma Power Inc.

Valid Until

May 4, 2029

Brian Hewson
Vice President, Consumer Protection and Industry Performance
Ontario Energy Board

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

Commission de l’énergie de l’Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

LIST OF AMENDMENTS

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EB-2023-0100	April 20, 2023

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1 Definitions

In this Licence:

“**Accounting Procedures Handbook**” means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

“**Act**” means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

“**Affiliate Relationships Code for Electricity Distributors and Transmitters**” means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

“**distribution services**” means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

“**Distribution System Code**” means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

“**Electricity Act**” means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

“**IESO**” means the Independent Electricity System Operator;

“**Licensee**” means Algoma Power Inc.;

“**Market Rules**” means the rules made under section 32 of the Electricity Act;

“**OPA**” means the Ontario Power Authority;

“**Performance Standards**” means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

“**Rate Order**” means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

“**regulation**” means a regulation made under the Act or the Electricity Act;

“**Retail Settlement Code**” means the code approved by the Board which, among other things, establishes a distributor’s obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

“**service area**” with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee’s premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on May 5, 2009 and expire on May 4, 2029. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender=s transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

21 Conservation and Demand Management

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22 Pole Attachments

22.1 The Licensee shall provide access to its distribution poles to all Canadian carriers, as defined by the Telecommunications Act, and to all cable companies that operate in the Province of Ontario. For each attachment, with the exception of wireless attachments, the Licensee shall charge the rate approved by the Board and included in the Licensee's tariff.

22.2 The Licensee shall:

a) annually report the net revenue, and the calculations used to determine that net revenue, earned from allowing wireless attachments to its poles. Net revenues will be accumulated in a deferral account approved by the Board;

b) credit that net revenue against its revenue requirement subject to Board approval in rate proceedings; and

c) provide access for wireless attachments to its poles on commercial terms normally found in a competitive market.

23 Administration of COVID-19 Energy Support Program

23.1 For the purposes of paragraphs 23.1 to 23.8:

“Application Form” means the form of application for CEAP approved by the Board, including the use of that form by telephone

“CEAP” means the COVID-19 Energy Assistance Program as described in the Board’s Decision and Order dated June 16, 2020

“CEAP-eligible account” means an account in the Licensee’s residential class that meets all of the following criteria:

(a) the account was in good standing (i.e. all amounts on account of electricity charges that were payable were fully paid) on March 17, 2020, and the account was not enrolled in an arrears payment for amounts owing prior to March 17, 2020

(b) complete payment on account of electricity charges has not been made on at least two electricity bills issued since March 17, 2020, and the account has an Overdue Balance on the date of receipt of the Application Form for the account including where the account is enrolled in an arrears payment agreement for amounts incurred following March 17, 2020,

(c) the account has not received funding under the Low-income Energy Assistance Program or the Ontario Electricity Support Program in 2020; and

(d) the account holder has provided a complete Application Form and has declared, through the Application Form, that they or their spouse or common-law partner that resides in the same residence:

- are unemployed on the date that they provide their completed Application Form to the Licensee

- have received Employment Insurance or the Canada Emergency Response Benefit since March 17, 2020

“Overdue Balance” means the amount by which the account holder’s balance is past due in respect of Electricity Charges at the time the Application Form is received by the Licensee. Amounts that may be on the bill but are not yet past due are not part of the Overdue Balance.

“electricity charges” means:

(a) charges that appear under the sub-headings “Electricity”, “Delivery”, and “Regulatory Charges” as described in Ontario Regulation 275/04 (Information on Invoices to Certain Classes of Consumers of Electricity) made under the Act, and all applicable taxes on those charges;

(b) where applicable, charges prescribed by regulations under section 25.33 of the Electricity Act and all applicable taxes on those charges

(c) Board-approved specific service charges, including late payment charges, and such other charges and applicable taxes associated with the consumption of electricity as may be required by law to be included on the bill issued to the customer or as may be designated by the Board for the purposes of this definition, but not including security deposits, amounts owed by a customer pursuant to a billing adjustment, or amounts under an arrears payment agreement entered into prior to March 17, 2020; and

(d) any financial assistance provided for under the *Ontario Rebate for Electricity Consumers Act, 2016*

23.2 The Licensee shall start to accept Application Forms as of July 13, 2020.

23.3 The Licensee shall:

(a) Make copies of the Application Form available on its web site and to any customer on request.

(b) Process all complete Application Forms in the order in which they are received.

(c) Accept Application Forms by e-mail or mail, and may also allow the Application Form to be completed online or by telephone, provided that where Application Forms are completed by telephone the call must be recorded and must document confirmation of all information requested on the Application Form, including consent and the applicant's declaration of eligibility.

(d) Process each complete Application Form within 10 business days of receipt.

23.4 The Licensee shall provide a credit to a CEAP-eligible account in an amount equal to half of the Overdue Balance for the account:

(a) to a maximum of $230, where the Application Form declares that the account is for a residence that mainly uses electric heating or in which an eligible medical device is used

(b) to a maximum of or $115, in all other cases.

23.5 The credit must be applied on the next bill issued to the CEAP-eligible account after the processing of the Application Form for the account as set out in paragraph 12.3(d), where feasible, and in any event no later than on the following bill.

23.6 Despite paragraph 23.4:

(a) The Licensee is not required to provide a credit to a CEAP-eligible account if the total amount of CEAP funding available to the Licensee as specified by the Board has been expended; and

(b) The Licensee shall not provide a credit to a CEAP-eligible account more than once.

23.7 Reimbursement for credits provided by the Licensee to CEAP-eligible accounts, up to the total referred to in paragraph 23.5(a), are recoverable from the Independent Electricity System Operator. The Licensee shall provide information in such form and manner, and within such time, as the IESO may reasonably require, in respect of requests for reimbursement. The Licensee shall not seek reimbursement from the Independent Electricity System Operator for any amount above the total referred to in paragraph 23.5(a) or on account of any costs relating to the administration of CEAP.

23.8 The Licensee shall keep the following records for two years, and make them available to the Board upon request:

(a) Copies of all Application Forms received, including recordings of calls where the Application Form is provided by telephone, and copies of any communications with customers about CEAP.

(b) A record of all Application Forms that were accepted as complete and a credit was provided to CEAP-eligible accounts, and a record of all Application Forms that were denied

(c) A record of the credit provided to each CEAP-eligible account, as well as the total amount of credits provided to all CEAP-eligible accounts.

23.9 The Licensee shall report to the Board, as soon as practicable, the date on which to total amount of CEAP funding referred to in paragraph 23.5(a) has been expended.

23.10 Paragraphs 23.1 to 23.8 govern over any provisions of the Distribution System Code or the Standard Supply Service Code in the event of any inconsistency.

24 Administration of COVID-19 Energy Support Program – Small Business

24.1 For the purposes of paragraphs 24.1 to 24.8:

“Application Form” means the form of application for CEAP-SB approved by the Board, including the use of that form by telephone

“CEAP-SB” means the COVID-19 Energy Assistance Program – Small Business as described in the Board’s Decision and Order dated August 7, 2020

“CEAP-SB eligible account” means an account for premises in the Licensee’s GS<50 class (for electricity distributors) / relevant commercial class and whose annual usage is less than 150,000 kWh (for USMPs) that meets all of the following criteria:

a) the account holder has a registered business number or charitable registration number for the business or registered charity operating out of the premises,

b) the account was in good standing (i.e. all amounts on account of electricity charges that were payable were fully paid) on March 17, 2020, and the account was not enrolled in an arrears payment agreement for amounts owing prior to March 17, 2020,

c) complete payment on account of electricity charges has not been made on at least two electricity bills issued since March 17, 2020, and the account has an Overdue Balance on the date of receipt of the Application Form for the account including where the account is enrolled in an arrears payment agreement for amounts incurred following March 17, 2020,

d) the account holder has confirmed in the Application Form that it is not applying for a CEAP-SB credit for another location or electricity account anywhere in the Province of Ontario for the same small business or registered charity,

e) the account holder has provided a complete Application Form and has declared, through the Application Form, that their small business or registered charity's premises was required to close to the public for regular operations for at least 15 days as a result of a government order or inability to comply with public health recommendations.

Note that the Licensee is only required to verify the information in items (b), (c), and (e) above.

"electricity charges" means:

a) charges that appear under the sub-headings "Electricity", "Delivery", and "Regulatory Charges" as described in Ontario Regulation 275/04 (Information on Invoices to Certain Classes of Consumers of Electricity) made under the Act, and all applicable taxes on those charges;

b) where applicable, charges prescribed by regulations under section 25.33 of the Electricity Act and all applicable taxes on those charges

c) Board-approved specific service charges, including late payment charges, and such other charges and applicable taxes associated with the consumption of electricity as may be required by law to be included on the bill issued to the customer or as may be designated by the Board for the purposes of this definition, but not including security deposits, amounts owed by a customer pursuant to a billing adjustment, or amounts under a payment agreement entered into prior to March 17, 2020; and

d) any financial assistance provided for under the *Ontario Rebate for Electricity Consumers Act, 2016;* and

"Overdue Balance" means the amount by which the account holder's balance is past due in respect of Electricity Charges at the time the Application Form is received by the Licensee. Amounts that may be on the bill but are not yet past due are not part of the Overdue Balance.

24.2 The Licensee shall start to accept Application Forms as of August 31, 2020.

24.3 The Licensee shall:

a) Make copies of the Application Form available on its web site and to any customer on request.

b) Process all complete Application Forms in the order in which they are received.

c) Accept Application Forms by e-mail or mail, and may also allow the Application Form to be completed online or by telephone, provided that where Application Forms are completed by telephone the call must be recorded and must document confirmation of all information requested on the Application Form, including consent and the applicant's declaration of eligibility.

d) Process each complete Application Form within 10 business days of receipt.

24.4 The Licensee shall provide a credit to a CEAP-SB eligible account up to the amount of the Overdue Balance for the account:

a) to a maximum of $850, where the Application Form declares that the account is for small business or registered charity premises that primarily uses electricity for heating; or

b) to a maximum of or $425, in all other cases.

The credit must be applied on the next bill issued to the CEAP-SB eligible account after the processing of the Application Form for the account as set out in paragraph 24.3(d), where feasible, and in any event no later than on the following bill.

24.5 Despite paragraph 24.4:

a) The Licensee is not required to provide a credit to a CEAP-SB eligible account if the total amount of CEAP-SB funding available to the Licensee as specified by the Board has been expended; and

b) The Licensee shall not provide a credit to a CEAP-SB eligible account more than once.

24.6 Reimbursement for credits provided by the Licensee to CEAP-SB eligible accounts, up to the total referred to in paragraph 24.5(a), are recoverable from the Independent Electricity System Operator. The Licensee shall provide information in such form and manner, and within such time, as the IESO may reasonably require, in respect of requests for reimbursement. The Licensee shall not seek reimbursement from the Independent Electricity System Operator for any amount above the total referred to in paragraph 24.5(a) or on account of any costs relating to the administration of CEAP-SB.

24.7 The Licensee shall keep the following records for two years, and make them available to the Board upon request:

a) Copies of all Application Forms received, including recordings of calls where the Application Form is provided by telephone, and copies of any communications with customers about CEAP-SB.

b) A record of all Application Forms that were accepted as complete and a credit was provided to CEAP-SB eligible accounts, and a record of all Application Forms that were denied.

c) A record of the credit provided to each CEAP-SB eligible account, as well as the total amount of credits provided to all CEAP-SB eligible accounts.

24.8 The Licensee shall report to the Board, as soon as practicable, the date on which the total amount of CEAP-SB funding referred to in paragraph 24.5(a) has been expended.

24.9 Paragraphs 24.1 to 24.8 govern over any provisions of the Distribution System Code or the Standard Supply Service Code in the event of any inconsistency.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The Licensee is licensed in respect to the geographic area comprised of the following list of townships:

Memaskwosh	Wishart	Miskokomon
Alanen	Herrick	Dulhut
Charbonneau	Tilley	Nebon
Dahl	Marne	Laronde
Dumas	Havilland	Redsky
Finan	Shields	Allouez
Riggs	Kars	Stone
Rennie	Vankoughnet	Alaire
Keating	Hodgins	Barager
Knicely		Bray
Leclaire	Aweres	Broome
Aguonie	Anderson	Goodwillie
Bruyere		Grootenboer
Legarde Add'l	Garden River Reserve IR14	Labonte
Levesque	Chesley Add'l	Peever
Menzies	Aberdeen	Raaflaub
Corbiere		Smilsky
Debassige	Tarbutt & Tarbutt Add'l	Tronsen
Echum	Plummer Add'l	Nicolet
Warpula	Rose	Olsen
Michipicoten	St. Joseph	Palmer
Fiddler	Jocelyn	Brule
Keesickquayash	Ashley	Fisher
Groseilliers	Chapais	Archibald
Bostwick	Dambrossio	Ley
Lastheels		Tupper
Michano	Jacobson	Gaudette
Nadjiwon	West	Fenwick
Rabazo	Stover	Deroche
Nebonaionquet	Killins	Whitman

Peterson	Lalibert	Pennefather
Restoule	Abotossaway	Jarvis
Tiernan	Bird	Chesley
Stoney	Copenace	Noganosh
Asselin	Legarde	Pawlis
Barnes	Macaskill	Quill
Brimacombe	Musquash	Giles
Bullock	Cowie	Rix
Greenwood	Dolson	Duncan
Labelle	St. Germain	Kehoe
Larson	Andre	MacDonald, Meredith & Aberdeen Add'l
Home	Esquega	Galbraith
Slater	Isaac	Laird
Tolmonen	Laforme	Johnson
Kincaid	Franchere	
Norberg	Michipicoten	Hilton
Ryan	Maness	Morin

2. Concessions 3, 4 and 5 of the Township of Dennis;

3. Approximately forty (40) square kilometres at the western limit of the former Township of Thessalon;

4. 5 rural customers in Kirkwood Township supplied off two short line taps into the Township;

5. Plus the following locations within the City of Sault Ste. Marie:

   (a) 45 Third Line West as at March 14, 2003, excluding those areas of land within 45 Third Line West that are serviced by PUC Distribution Inc. (PUC) as identified in PUC's distribution licence, those being:

   - the areas of land on which the facilities on the northeast corner of 45 Third Line West are located, namely the "gatehouse" and "office";

   (b) 77 Third Line West as at July 9, 2004;

   (c) 3 Sackville Road;

   (d) 150 Conmee Avenue;

   (e) 429 Hudson Street, excluding those areas within 429 Hudson Street that are serviced by PUC as identified in PUC's distribution licence, those being:

(i) the area of land on which the facility near the northwest corner of Hudson Street and Wellington Street West is located, namely the “yard office”;

(ii) the area of land on which the facility near the junction of Hudson Street and St. George Avenue West is located, namely the “skimmer shack”; and

(iii) the area of land on which the railroad crossing signals are located, near the junction of Hudson Street and St. Andrew Terrace; and

(f) 2 Sackville Road.

6. The service area excludes the following locations west of Thessalon on the north side of Hwy.17 which are supplied by Hydro One Networks Inc.:

(a) 12564 Highway 17 West

(b) 12600 Highway 17 West

7. The Township of Dubreuilville.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

1. The Licensee is exempt from the provisions of the Standard Supply Service Code requiring standard time-of-use pricing or, if the consumer so elects, ultra-low overnight time-of-use pricing, for Regulated Price Plan consumers with eligible time-of-use meters (namely, sections 3.2.6, 3.4, 3.4A, 3.4B and 3.5). This exemption applies only for service to the approximately 200 “hard to reach” customers who, as of March 2023 were outside the effective coverage area of the Licensee’s smart meter telecommunications infrastructure. This exemption expires on December 31, 2024. If, during the exemption period, a previously hard to reach customer comes within the effective coverage area of the Licensee’s smart meter telecommunications infrastructure, the Licensee must as soon as practicable provide the customer with the option of electing standard time-of-use, ultra-low overnight time-of-use or tiered prices and begin charging the customer based on the customer’s election or, if no election is made, based on standard time-of-use prices.

2. The Licensee is exempt from the requirements of the following sections of the Affiliate Relationships Code for Electricity Distributors and Transmitters under the conditions specified in section 2 of this Schedule:

   Section 2.2.2

   Where a utility shares information services with an affiliate, all confidential information must be protected from access by the affiliate. Access to a utility’s information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. A utility shall, if required to do so by the Board, conduct a review of the adequacy, implementation or operating effectiveness of the access protocols and associated contractual provisions which complies with the provision of section 5970 of the CICA Handbook. A utility shall also conduct such a review when the utility considers that there may have been a breach of the access protocols or associated contractual provisions and that such review is required to identify any corrective action that may be required to address the matter. The utility shall comply with such directions as may be given by the Board in relations to the terms of section 5970 review. The results of any such review shall be made available to the Board.

   Section 2.2.3

   A utility shall not share with an affiliate that is an energy service provider employees that are directly involved in collecting, or have access to, confidential information.

3. The Exemptions from the requirements of the Affiliate Relationship Code for Electricity Distributors and Transmitters referred to section 2 of this Schedule (the “Exemptions”) are subject to the following conditions:

   a) The exemptions only apply in respect of the relationship between the Licensee and the following affiliates and not with respect to any other affiliates of the Licensee:

      - FortisOntario Inc.;

      - Fortis Properties Corporation; and

- Cornwall Street Railway Light and Power Company Limited.
- Canadian Niagara Power Inc.

b) The Licensee shall not share facilities, confidential information or employees with any affiliate identified in paragraph a) for any purpose other than the provision of services to, or the receipt of services from, the affiliate under the Services Agreements dated September 15, 2010 (the “Services Agreements”) as filed with the Board as part of the materials filed in support of the application for the Exemptions, as such Services Agreements may be amended from time to time.

c) The activities of the Licensee relative to the affiliates identified in paragraph a) shall be governed by, and the Licensee shall be bound by and comply with, the Services Agreements, as amended from time to time.

d) The Licensee shall notify the Board of any material change relative to the materials filed in support of the application for the Exemptions as soon as possible upon becoming aware of such change and in no event later than fifteen days following the date on which the change occurs. Without limiting the generality of the foregoing, this obligation includes notifying the Board in the event of a change in the market activities of either FortisOntario Inc. or Fortis Properties Corporation.

e) The Board may, on its own initiative or upon receipt of notice from the Licensee under paragraph d), by order revoke one or more of the Exemptions, vary one or more of the conditions set out above or impose additional conditions upon becoming aware of any material change relative to the materials filed in support of the application for Exemptions, or for such other reason as the Board considers appropriate.

4. The Licensee is exempt from the provisions of Section 2.10.1 and Sections 7.11.1 to 7.11.7 of the Distribution System Code limiting the use of estimated billing and requiring billing accuracy. This exemption applies only for service to approximately 191 of the identified hard to reach customers who would fail to meet the Distribution System Code requirements for accurate bills. The identified customers include customers who are outside the effective coverage areaof the Licensee’s smart meter telecommunications infrastructure. This exemption expires on December 31, 2024.

5. The Board will refrain from enforcing regulatory requirements that are within its control insofar as such requirements relate to circumstances or defects inherited by the Licensee through its acquisition of the distribution system formerly owned by Dubreuil Lumber Inc. (as set out in former Electricity Distributor Licence ED-2012-0074 and Interim Electricity Distributor Licence ED-2017-0153) provided, however, that upon becoming aware of any such circumstance or defect relating to the acquired Dubreuil Lumber Inc. system, the Licensee shall take reasonable steps to address those circumstances or defects within a reasonable period. For greater certainty, this condition does not preclude the Board from investigating and requiring resolution of any compliance matters. This relief expiries on December 31, 2024.

APPENDIX A

MARKET POWER MITIGATION REBATES

2. **Definitions and Interpretations**

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

3. **Information Given to IESO**

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

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In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Attachment 1I

Customer Engagement Report

Algoma Power Inc.
EB-2024-0007

2025 Customer Engagement
Online Workbook Report

This report and all of the information and data contained within it may <u>not</u> be released, shared or otherwise disclosed to any other party, without the prior, written consent of Algoma Power Inc.

February 2024

PROPRIETARY AND CONFIDENTIAL

Table of Contents

Within the proposed increase

Customer Engagement Planning Placemat

Below is a summary of the results from Algoma Power's 2025-2029 Rate Application customer engagement. These results have been broken down by rate class to highlight potential differences.

	Residential [n=1,000]	Seasonal [n=350]	Small Business [n=35]	Large Business [n=7]
Pole and Line Replacement				
Accelerated pace	24%	20%	9	1
Current approach	62%	60%	22	5
Slower pace	14%	19%	4	1
Substation Rebuild				
Like-for-like capacity	15%	21%	5	2
50% capacity increase	47%	58%	19	5
100% capacity increase	38%	21%	11	-
Voltage Conversion				
Minimum level	13%	21%	2	2
Mid level	54%	54%	27	5
Full level	33%	25%	6	-
Preparing for Increased Electricity Demand				
Status quo	38%	55%	18	5
25% proactive replacement	44%	30%	13	2
50% proactive replacement	18%	16%	4	-

Within the proposed increase

Customer Engagement Planning Placemat (Con't)

	Residential [n=1,000]	Seasonal [n=350]	Small Business [n=35]	Large Business [n=7]
Automated "Intelligent" Switches				
Status quo	17%	24%	5	1
Partial implementation	27%	32%	15	2
Full implementation	56%	43%	15	4
Vegetation Management				
Reduced cycle approach	13%	15%	4	1
Standard cycle approach	67%	67%	22	5
Increased cycle approach	21%	19%	9	1
Overall Plan Evaluation				
Spend more	33%	21%	10	1
Spend according to draft plan	52%	52%	19	5
Spend less	5%	17%	5	1

Introduction

Representative Online Workbook

Algoma Power 2025-2029 Rate Application Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Algoma Power 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 customer engagements.

Setting the Context

Algoma Power is in the process of finalizing its 2025-2029 Investment Plan. This report covers the results of a series of customer "workbook" surveys that were used to gather customer preferences on program expenditures in the upcoming five-year period. This "workbook" survey was deployed to all customers with an email address, as well as promoted through a generic link on Algoma Power's website and social media platforms.

Interpreting the Results

Residential and Seasonal responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. INNOVATIVE is confident that the residential and small business online workbook results contained within this report are representative of Algoma Power's actual customer base.

Small Business and Large Business responses have not been weighted. Results for these customer classes have been expressed as frequencies due to smaller sample size.

Introduction

Region, Consumption, and Environmental Control Segmentation

Region and Environmental Control Segmentation

In addition to segmenting customers based on region and average annual consumption, it is important to be able to identify factors outside of Algoma Power's control that may influence customer needs and preferences.

Perceptions of LDCs often tend to move with general perceptions of the sector rather than in response to the local utility.

Throughout this report, environmental control questions are used to help distinguish whether opinions regarding Algoma Power's plans are general perceptions or preferences specific to Algoma Power.

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

1. **Region:** Using customer data provided by Algoma Power, we split customers into three regions for analysis based on the first three characters of their postal code; North/West, East, and Central.

    - **Central**: Areas immediately surrounding Sault Ste. Marie
    - **North/West**: All Northern service territory, beginning just South of the Goulais River
    - **East**: East of Echo Bay to the Eastern edge of the service territory, inclusive of St. Joseph Island

2. **Consumption Quartile**: Using customer data provided by Algoma Power, we split customers into four quartiles based on their average annual electricity consumption.

3. **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.*

4. **General Sector Perceptions:** Segmentation that INNOVATIVE refers to as "General Sector Perceptions" is provided. This segment is determined based on the extent to which customers agree with the following statement: *Customers are well served by the electricity system in Ontario.*

5. **Vulnerable Consumers**: For residential customers, using a combination of household size and combined household income, the residential portion of this report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's *Low-income Energy Assistance Program* (LEAP) criteria.

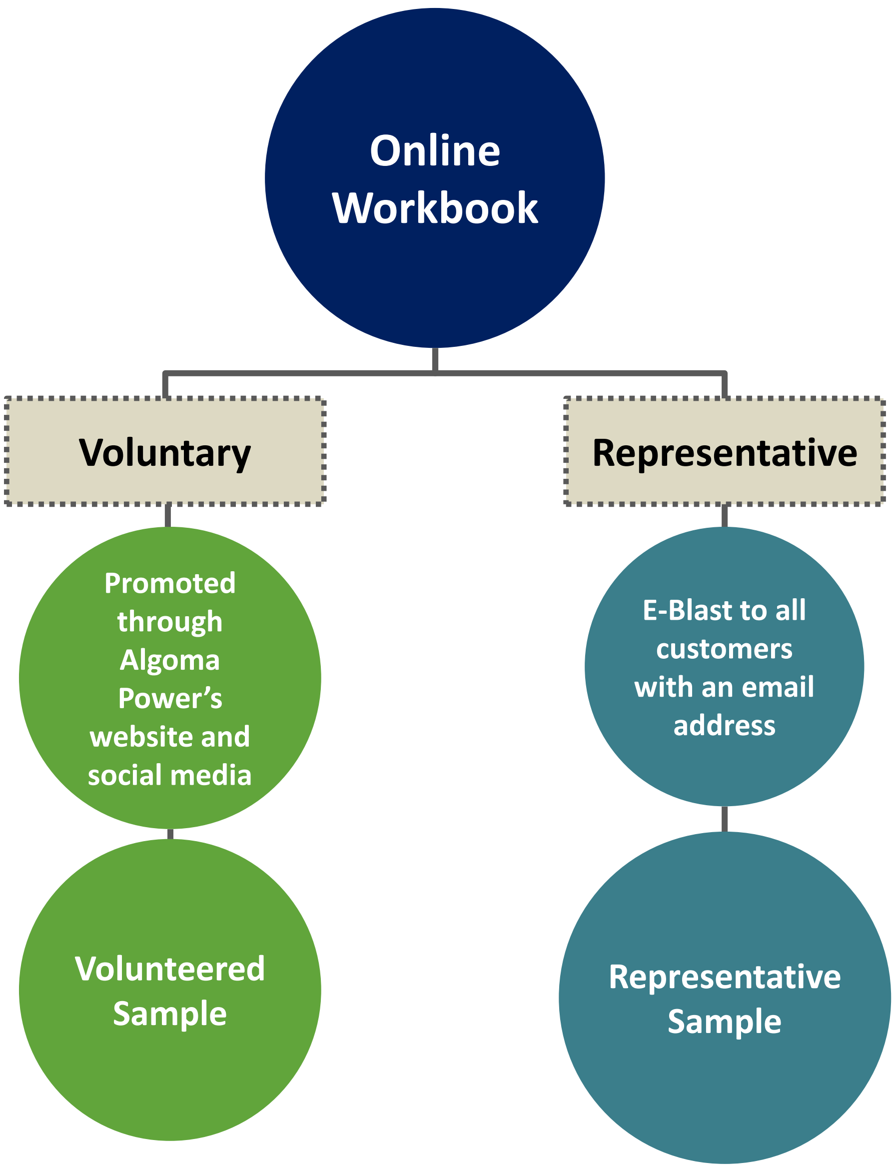
Sample Validation

Overall Approach

Algoma Power's residential, seasonal, and small business customer engagement workbooks featured two streams – *representative* and *voluntary*.

The voluntary stream was an open process that allowed anyone who wanted to be heard an opportunity to express themselves, including those who have not provided the utility with an email address. *Since this stream received 2 unique responses, those results are excluded from this report.*

The representative stream ensures a representative sample of customers are engaged, allowing for the generalizability of findings. ***This is a report of those responses.***



Sample Validation

Email Sample vs. Broader Sample

Comparing the overall population to the sample of that population with email addresses across known variables, it is apparent that no group is substantially underrepresented in the email sample.

Overall Coverage

Email coverage across all three of Algoma Power's low-density rate classes is high, with the lowest being residential at 67%. Coverage is highest among small business (GS<50) customers at 86%.

Rate Class	Full Population*	Email Sample*	Coverage
Residential	8,418 records	5,664 records	**67%**
Seasonal	2,700 records	1,885 records	**70%**
GS<50	1,007 records	861 records	**86%**

Average Consumption

Average monthly consumption is slightly higher among customers with emails when compared to the full customer population. The final data is weighted by consumption quartile to account for this.

Rate Class	Full Population	Email Sample	Difference
Residential	932 kWh	974 kWh	**+5%**
Seasonal	161 kWh	181 kWh	**+12%**
GS<50	2,308 kWh	2,370 kWh	**+3%**

*Numbers represent sample counts before duplicate email addresses are removed as to represent the entire population of your contract accounts

Sample Validation

Email Sample vs. Broader Sample

Comparing the overall population to the sample of that population with email addresses across known variables, it is apparent that no group is substantially underrepresented in the email sample.

Using the first three digits of postal codes (FSAs), customers are grouped into three unique regions. **There is no systematic pattern of regions being over or underrepresented by email.**

Dividing Algoma Power's service territory into distinct regions allows INNOVATIVE to ensure that no one area is over or underrepresented in the survey sample. Regions are determined based on population density and further analyzed based on the number of residential and small business customers in each region.

Rate Class	Region	Share of full population	Share of email sample	Difference
Residential	North/West	59%	60%	**0%**
	East	30%	31%	**+1%**
	Central	11%	9%	**-2%**
Seasonal	North/West	56%	54%	**-2%**
	East	40%	42%	**+2%**
	Central	5%	4%	**-1%**
GS<50	North/West	63%	64%	**+1%**
	East	30%	29%	**0%**
	Central	7%	7%	**0%**

INNOVATIVE
RESEARCH GROUP

INNOVATIVE
RESEARCH GROUP

Residential Customers

Online Workbook Results

Online Workbook

Survey Design & Methodology

INNOVATIVE was engaged by Algoma Power Inc. to gather input on their proposed draft 2025-2029 business plan. Throughout this report, actual pages of the workbook that customers completed are included in the order that they were seen and are indicated by a watermark that says, "workbook page".

Field Dates & Workbook Delivery

The **Residential Online Workbook** was sent to all Algoma Power residential customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **December 4th, 2023 and January 1st, 2024**.

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

In total, the residential workbook was sent to **4,830** customers via e-blast from INNOVATIVE.
Two additional reminder emails were sent to those who had not yet completed the workbook in order to encourage participation and maximize response.

Residential Online Workbook Completes

A total of **1,021** (unweighted) Algoma Power residential customers completed the online workbook via a unique URL.

Sample Weighting

The residential online workbook sample has been weighted proportionately by consumption quartiles and region in order to be representative of the broader Algoma Power service territory.

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

	Consumption Quartiles				Total
	First	Second	Third	Fourth	
North/West	143 (147)	152 (148)	172 (145)	151 (151)	618 (592)
East	69 (78)	95 (73)	88 (77)	71 (70)	323 (298)
Central	16 (25)	20 (29)	20 (28)	24 (28)	80 (110)
Total	228 (250)	267 (250)	280 (250)	246 (250)	1,021 (1,000)

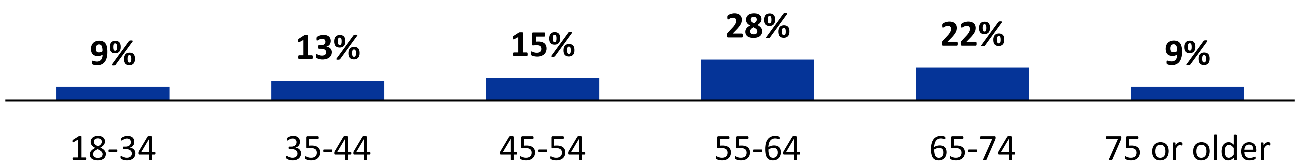
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Workbook

Demographic breakdown

Residential

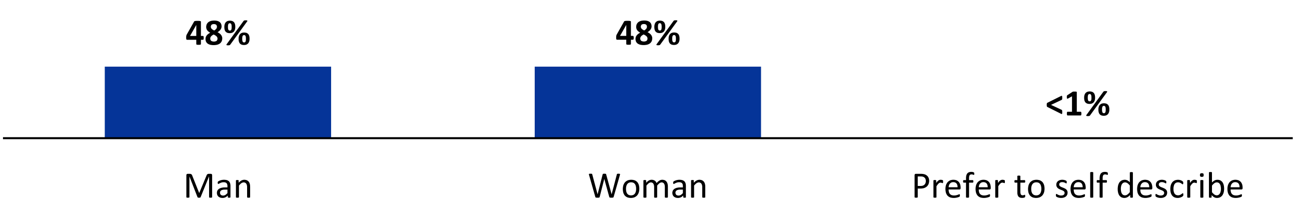
Q Age



"Prefer not to say"(2%) not shown.

n=1,000

Q Gender



"Prefer not to say"(3%) not shown.

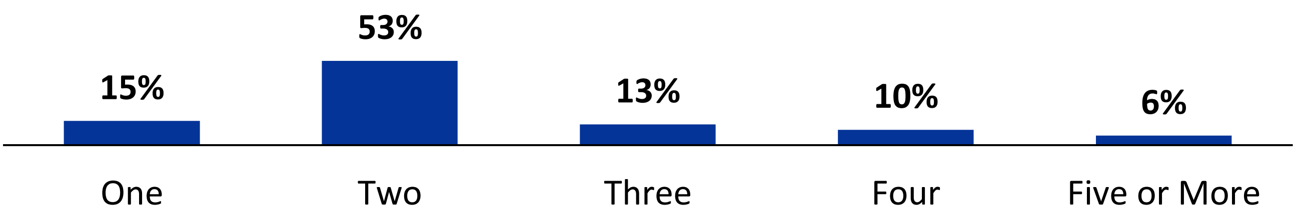
n=1,000

Online Workbook

Demographic breakdown

Residential

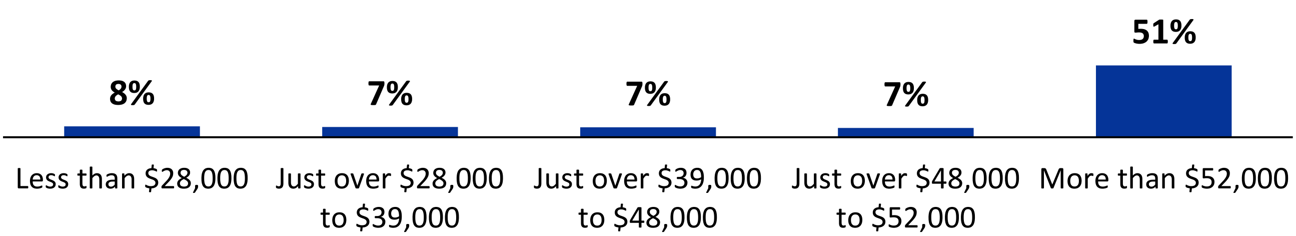
Q Household Size



"Prefer not to say" (2%) not shown.

n=1,000

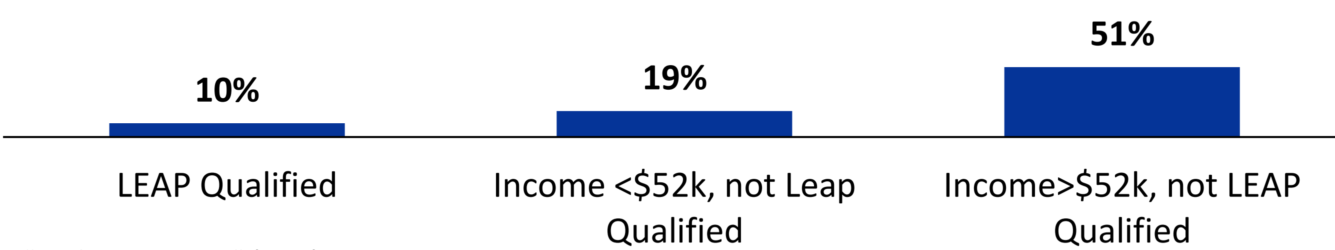
Q After Tax Household Income



"Prefer not to say" (20%) not shown.

n=1,000

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



"Prefer not to say" (20%) not shown.

n=1,000

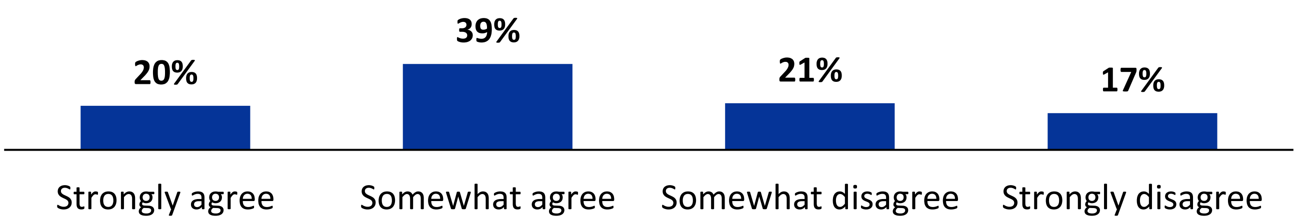
Online Workbook

Environmental Controls

Residential

Now we would like to shift the focus and ask you some general questions about the electricity system in Ontario. To what extent do you agree or disagree with the following statements?

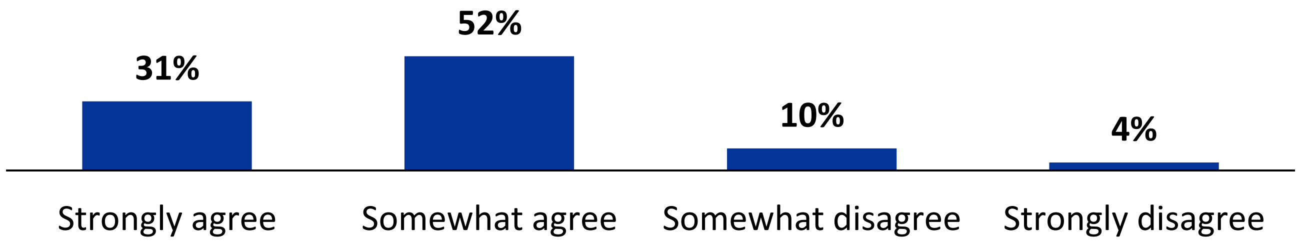
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



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

n=1,000

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



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

n=1,000

Online Workbook

Residential

Planning for the Future: 2025-2029 Rate Application

About this Customer Engagement

Welcome to Algoma Power's customer engagement survey!

Over the course of the past year, Algoma Power has been developing its 2025-2029 business plan.

- **Today, Algoma Power is looking for your input on its draft plan** to ensure it is making spending decisions that matter to you, the customer.
- **In early 2024, Algoma Power plans to justify and present** its business plans to the public regulator, the Ontario Energy Board (OEB).
- **Beginning in 2025, based on the OEB's approval, Algoma Power will be updating the rate that you pay** for the delivery of electricity to your home or business.

This survey will take approximately 20 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved and you can return to the customer engagement at any time.

Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback and protect your confidentiality.

Those who complete the questions that follow will be invited to enter a draw to win one (1) of two (2) $500 VISA gift cards.

We thank you for your valuable time.

While the survey can be completed on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop computer, or laptop instead so that it is easier for you to read.

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Residential

About this Customer Engagement

What do we want to talk about?

Today's engagement will focus on two key areas while also allowing you to "colour outside the lines" and tell us what you think more broadly.

1. First, this engagement will seek to understand **what you feel Algoma Power should be prioritizing** over the next five years.

2. Next, you will be asked some questions about **specific investment decisions Algoma Power needs to make** related to overhead poles, wire, and other critical infrastructure.

But first, we need to ensure that we are all on the same page regarding Algoma Power's role in the broader electricity system, how much of your bill goes to Algoma Power, and where that money goes.

Online Workbook

Residential

Planning for the Future: 2025-2029 Rate Application

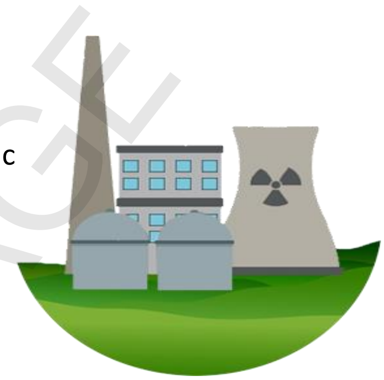
Electricity 101

Algoma Power's role in Ontario's electricity system

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

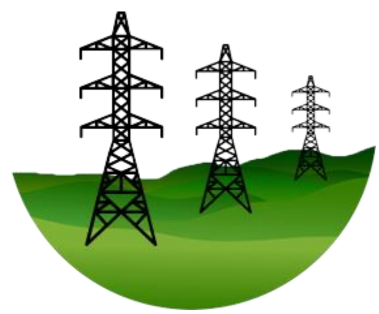


Ontario gets its electricity from a mix of energy sources. More than half comes from nuclear power. The remainder comes from a mix of hydroelectric and natural gas, and to a lesser extent, wind and solar.

Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from multiple generators who have contracts with the grid operator to provide power from a variety of sources.

Transmission

How electricity travels across Ontario



Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which are owned and operated by Hydro One.

Local Distribution

How electricity is delivered to the end-consumer

Algoma Power is responsible for the last step of the journey: distributing electricity to customers through its distribution system.

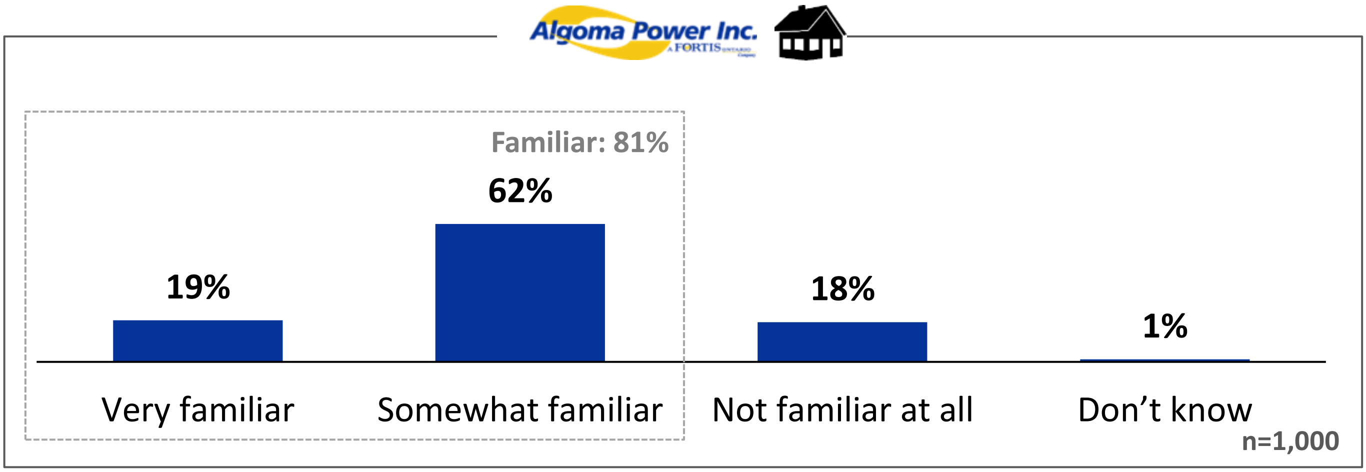
- Algoma Power manages all aspects of the electricity distribution business throughout the Algoma District of northern Ontario.
- In your community, amongst other functions, Algoma Power is responsible for:
    - Building and maintaining the local electricity distribution system
    - Responding to outage calls 24/7
    - Reading meters
    - Producing bills and accepting bill payments

Online Workbook

Familiarity with Algoma Power

Residential

Q Before this survey, how familiar would you say you were with Algoma Power and the role it plays in Ontario's electricity system?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Very familiar	17%	23%	16%	19%	19%	20%	17%	22%	15%	19%
Somewhat familiar	63%	61%	61%	65%	63%	59%	61%	58%	67%	61%
Not familiar at all	18%	16%	22%	15%	16%	21%	20%	18%	17%	19%
Don't know	1%	1%	1%	1%	1%	<1%	2%	3%	1%	1%
Familiar (Very + Somewhat)	**80%**	**84%**	**77%**	**84%**	**82%**	**79%**	**78%**	**80%**	**81%**	**80%**

Online Workbook

Residential

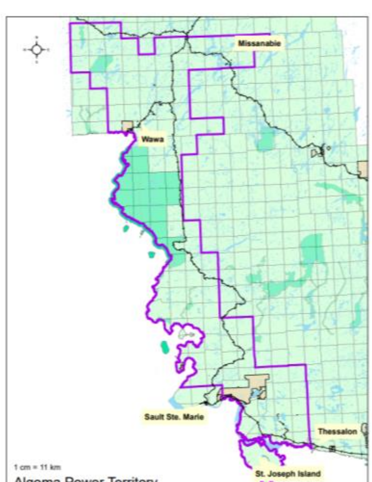
Planning for the Future: 2025-2029 Rate Application

Electricity 101

Who is Algoma Power?

Algoma Power services in the remote areas of Northern Ontario, extending 93 km east and approximately 340 km north of the City of Sault Ste. Marie, for a total of 14,200 km^2 of service territory, the second largest in Ontario.

- **Algoma Power does not generate or transmit electricity** — it owns and operates the local electricity system.
- **Algoma Power services about 12,000 customers,** over 14,200 km^2, making it the lowest-density distributor in Ontario. As a result of the low number of customers in such a large area, the cost to provide service to each customer on average is higher, as Algoma Power must install more equipment (ex: longer lines) to provide service to each customer.
- **Historically, much of Algoma Power's distribution system was built to service the resource sector and the communities that developed around those enterprises**. As a number of those industries declined or relocated, the result is a sparsely populated service territory with predominantly residential and seasonal customers.
- **As with all other local distribution companies in Ontario, Algoma Power is funded by the distribution rates that you pay on your electricity bill**. Unlike most other utilities, a portion of this funding is recovered through other provincial funds intended to manage the affordability of distribution rates for rural and remote customers.
- As a local distribution company (LDC) and regulated entity, **Algoma Power can only charge the rates the regulator approves to charge for its services.**
- **The OEB runs an open and transparent review process** where experts from the regulator and intervenor groups review and challenge Algoma Power's analyses and assessments.



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Planning for the Future: 2025-2029 Rate Application

Electricity 101

How much of my electricity bill goes to Algoma Power?

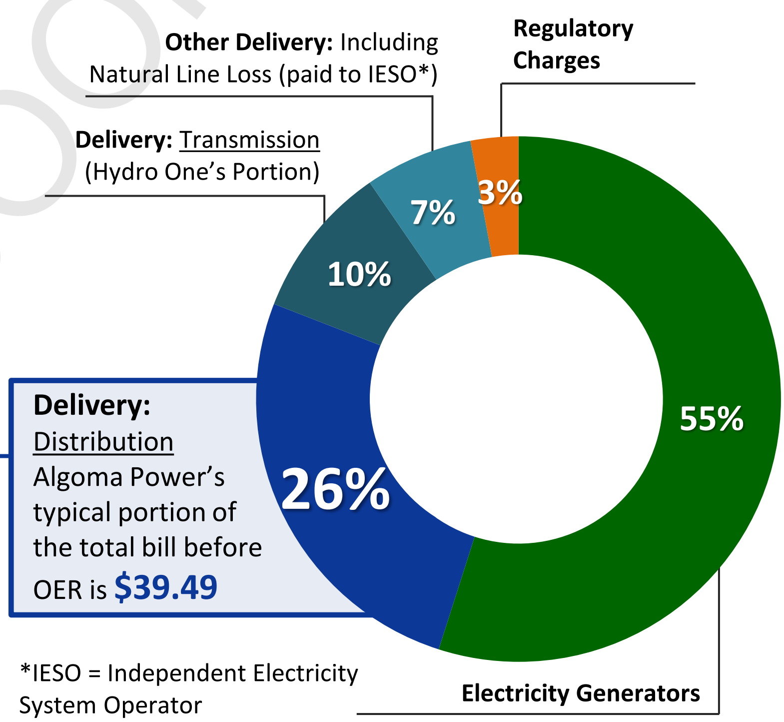
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While Algoma Power is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge. The delivery charge also includes Hydro One transmission costs and system losses.
- **Distribution makes up about 26% of the typical residential customer's bill, excluding the Ontario Electricity Rebate (OER) and Harmonized Sales Tax (HST).**
- The distribution portion of your bill, which goes towards operating and maintaining Algoma Power's distribution system, is largely fixed. Meaning, it does not change depending on how much electricity you use.
- The rest of your bill payment is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

Sample Algoma Power Monthly Bill
(based on consumption of 750 kWh as of Nov. 1, 2023)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 18.2 c/kWh	**25.94**
Mid-Peak (mid price) @ 12.2 c/kWh	**16.47**
Off-Peak (lowest price) @ 8.7 c/kWh	**41.11**
Delivery	**64.06**
Regulatory Charges	**4.47**
Total Electricity Charges	**$152.05**
HST	**19.77**
Ontario Electricity Rebate	**(-$29.35)**
Total Amount	**$142.47**



*IESO = Independent Electricity System Operator

Chart is based on total bill of $152.05 excluding the Ontario Electricity Rebate and HST. 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.

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Familiarity with Algoma Power

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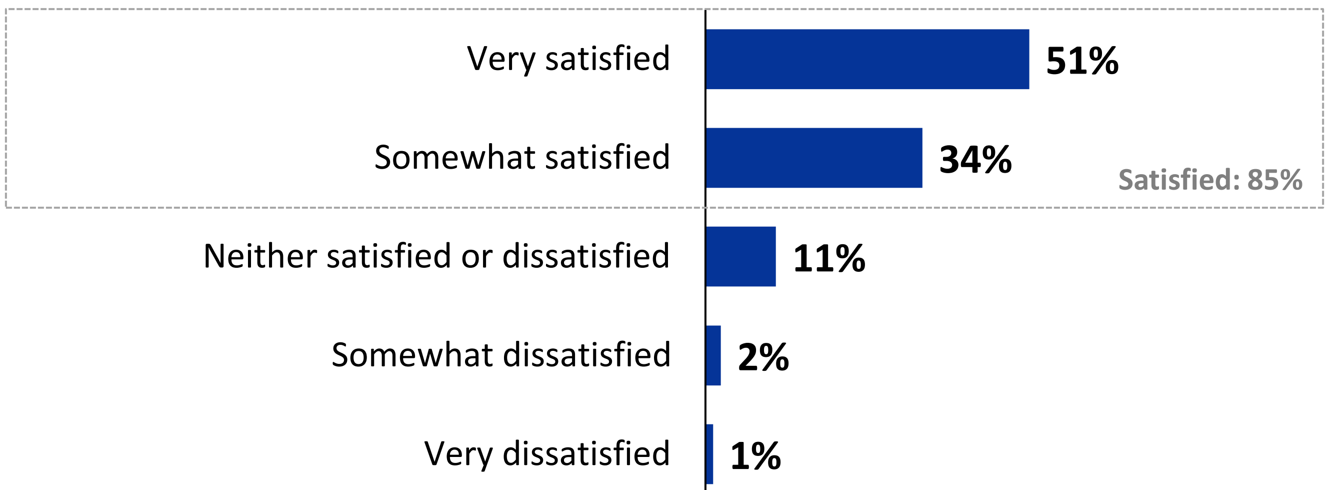
Q Thinking specifically about the services provided to you and your community by Algoma Power, overall, how satisfied or dissatisfied are you with the services that you receive?



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

n=1,000

	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Very satisfied	52%	51%	44%	56%	55%	46%	48%	56%	51%	52%
Somewhat satisfied	33%	32%	46%	31%	33%	36%	36%	32%	33%	33%
Neither satisfied nor dissatisfied	11%	12%	7%	10%	10%	12%	12%	9%	11%	11%
Somewhat dissatisfied	2%	4%	2%	1%	1%	4%	4%	2%	3%	3%
Very dissatisfied	1%	1%	1%	1%	1%	2%	1%	2%	2%	1%
Don't know	<1%	<1%	--	<1%	--	<1%	--	--	--	<1%
Satisfied (Very + Somewhat)	**85%**	**83%**	**90%**	**87%**	**88%**	**82%**	**83%**	**87%**	**84%**	**85%**
Dissatisfied (Very + Somewhat)	**3%**	**5%**	**4%**	**2%**	**1%**	**6%**	**5%**	**4%**	**4%**	**4%**

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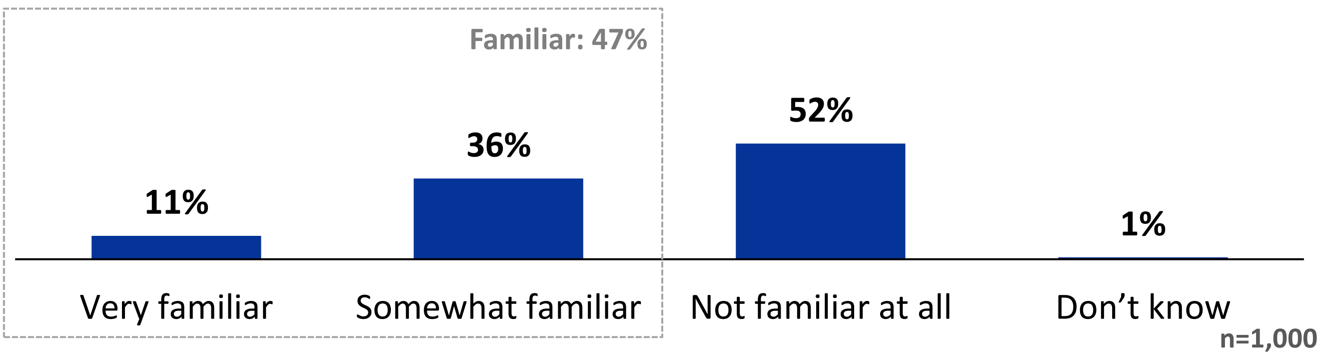
Familiarity with the Percentage of Bill Remitted to Algoma Power

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



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Very familiar	9%	13%	11%	11%	9%	11%	11%	10%	12%	10%
Somewhat familiar	35%	37%	41%	36%	39%	40%	31%	32%	39%	37%
Not familiar at all	55%	49%	46%	52%	51%	48%	57%	56%	49%	53%
Don't know	1%	1%	1%	<1%	1%	1%	2%	3%	--	1%
Familiar (Very + Somewhat)	**44%**	**50%**	**53%**	**47%**	**48%**	**51%**	**42%**	**42%**	**51%**	**46%**

Online Workbook

Residential

How Algoma Power can Improve Services to Customers

Q Is there anything in particular you would like Algoma Power to do to improve its services to you?

Additional Comments	%
Lower cost/rates/delivery charge	9.5%
Improve pole/line maintenance/better tree clearing/bury lines	4.4%
Improve communication for planned/unplanned outages	3.4%
Improve infrastructure/grid/reliability/power quality/number of outages	2.2%
Satisfied with service/no improvements necessary	2.0%
Adjust rates for seasonal properties/properties that consume no power some of the time	1.9%
Improve billing issues - clarity/explain costs/accuracy/payment methods/consistency	1.5%
Improve communication/transparency with customers	0.8%
Improve online resources/website/portal	0.5%
Improve customer service/administrative processes	0.4%
Information about transitioning to green energy	0.4%
Restore power quicker/faster response time	0.2%
Offer more alternative/green energy sources/less fossil fuels	0.2%
More community involvement	0.2%
Other	0.4%
Don’t know	71.7%
None	0.2%

Note: Only responses >0.1% shown

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Planning for the Future: 2025-2029 Rate Application

Residential

Electricity 101

Explaining "Distribution Rate Protection" and Rural Remote Rate Protection

Algoma Power is one of seven different utilities in Ontario that have a largely rural customer base.

As a rural customer, you benefit from two government programs that are designed to bring the distribution costs for rural and remote customers more in line with what urban customers pay for distribution. First Nation customers are eligible for the First Nation Delivery Credit.

- As of this year, the maximum monthly base distribution charge has been set at **$39.49**.
- That means, as long as these protections remain in place, customers like yourself won't pay more than the maximum amount set by the program.

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Familiarity with Government Programs

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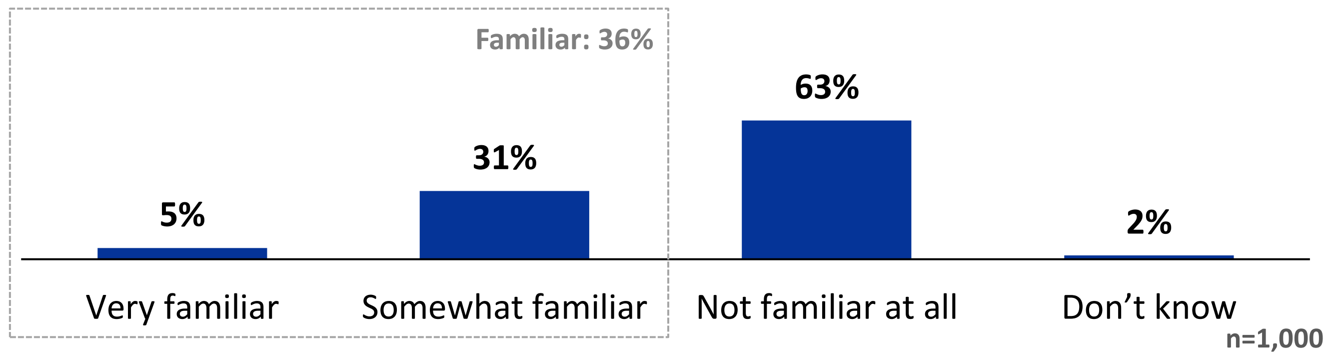
Q Before this survey, how familiar were you with these government programs which apply to rural Algoma Power customers and caps the amount of distribution charges you pay?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Very familiar	5%	5%	8%	8%	4%	5%	3%	6%	6%	5%
Somewhat familiar	30%	32%	33%	37%	29%	28%	29%	32%	34%	28%
Not familiar at all	64%	62%	57%	54%	66%	66%	65%	59%	59%	65%
Don't know	2%	1%	2%	1%	1%	2%	3%	3%	2%	2%
Familiar (Very + Somewhat)	**34%**	**37%**	**41%**	**45%**	**33%**	**33%**	**32%**	**38%**	**40%**	**33%**

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Online Workbook

Setting Priorities within Algoma Power's Plans

Residential

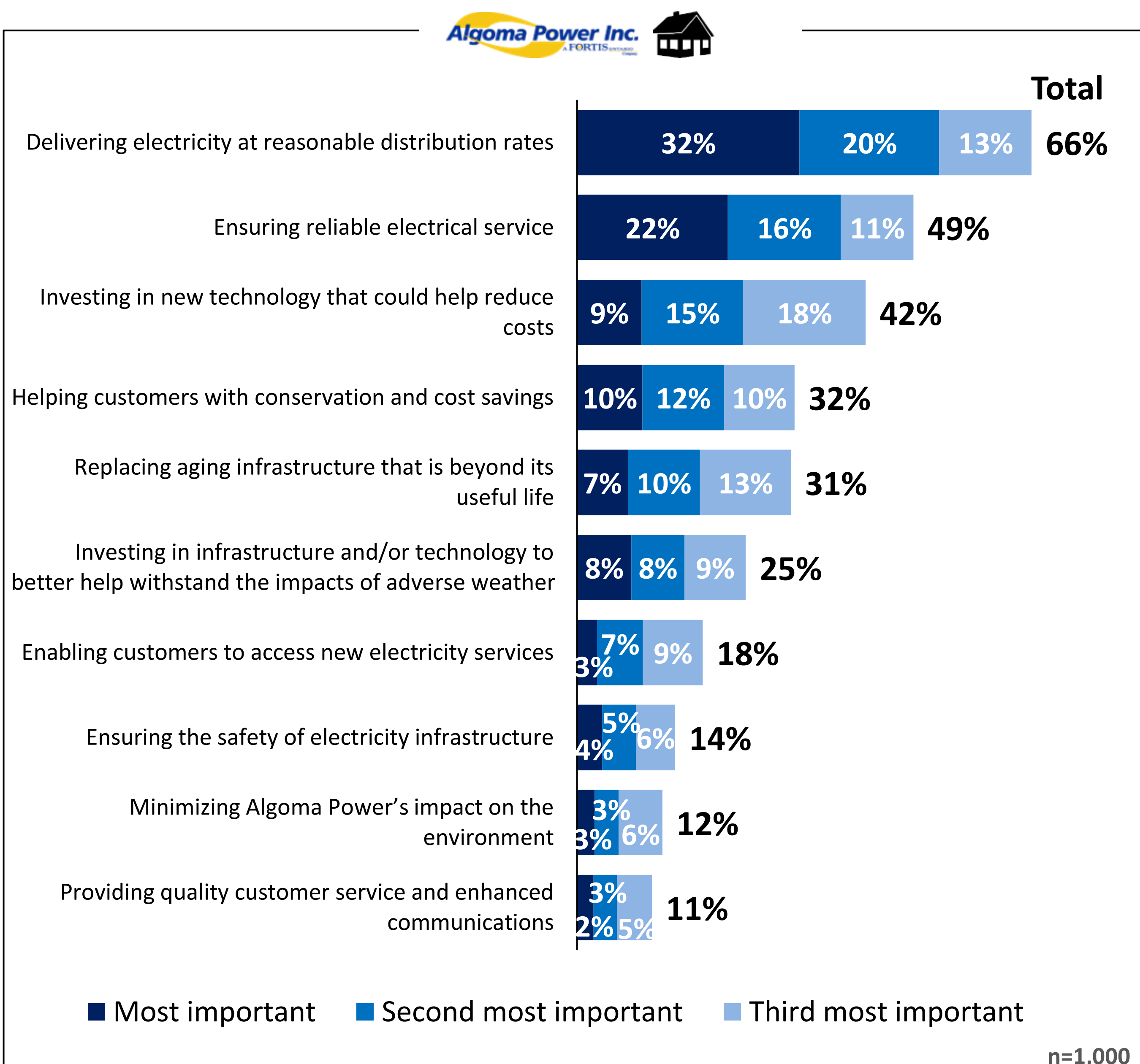
Q

As with all businesses, Algoma Power must make decisions on which areas they are going to prioritize within their business plans.

Based on ongoing conversations with customers, a number of company goals have been identified as priorities for Algoma Power.

Looking at the list below, please rank your top 3 priorities—where "1" would be the most important, "2" the second most important, and "3" the third most important.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, and ending with the third most important.



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Setting Priorities within Algoma Power's Plans

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% Total Important (top three)	Region			Consumption Quartiles			
	North/ West	East	Central	First	Second	Third	Fourth
Delivering electricity at reasonable distribution rates	69%	65%	54%	69%	62%	67%	66%
Ensuring reliable electrical service	46%	57%	42%	50%	50%	50%	45%
Investing in new technology that could help reduce costs	42%	42%	43%	43%	40%	39%	45%
Helping customers with conservation and cost savings	33%	28%	35%	28%	27%	36%	36%
Replacing aging infrastructure	29%	32%	40%	30%	33%	32%	29%
Investing in infrastructure/tech to withstand adverse weather	24%	24%	28%	24%	28%	21%	25%
Enabling customers to access new electricity services	20%	15%	16%	17%	15%	20%	21%
Ensuring the safety of electricity infrastructure	13%	17%	15%	14%	17%	11%	15%
Minimizing Algoma Power's impact on the environment	14%	9%	14%	16%	13%	11%	9%
Providing quality customer service	11%	11%	12%	8%	14%	12%	9%

% Total Important (top three)	LEAP Qualification		
	Yes	No <$52K	No >$52K
Delivering electricity at reasonable distribution rates	64%	63%	65%
Ensuring reliable electrical service	36%	46%	52%
Investing in new technology that could help reduce costs	31%	48%	40%
Helping customers with conservation and cost savings	32%	37%	30%
Replacing aging infrastructure	43%	28%	31%
Investing in infrastructure/tech to withstand adverse weather	31%	22%	25%
Enabling customers to access new electricity services	18%	21%	18%
Ensuring the safety of electricity infrastructure	19%	15%	14%
Minimizing Algoma Power's impact on the environment	15%	13%	13%
Providing quality customer service	11%	8%	12%

Online Workbook

Other Important Priorities

Residential

Q Can you think of any other important priorities that Algoma Power should be focusing on?

Additional Comments	%
Affordability/reducing costs	4.7%
Consider environmental impact/offer alternative energy options	2.4%
The priorities mentioned earlier are all important/all the above	2.3%
Better line maintenance/bury lines	1.7%
Preparing the grid/infrastructure for the future	1.4%
Improving reliability/reducing outages	1.0%
Enhancing outage communication	0.6%
Focus on safety measures/safety of workers	0.5%
Being transparent with customers	0.5%
Helping customers transition to new services	0.4%
Helping seniors/low income customers	0.4%
Educating customers on reducing power consumption	0.3%
Charge seasonal customers equally/stop overcharging seasonal customers	0.3%
Improve meter reading	0.3%
Other	1.5%
None	81.8%

Note: Only responses >0.1% shown

Online Workbook

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Planning for the Future: 2025-2029 Rate Application

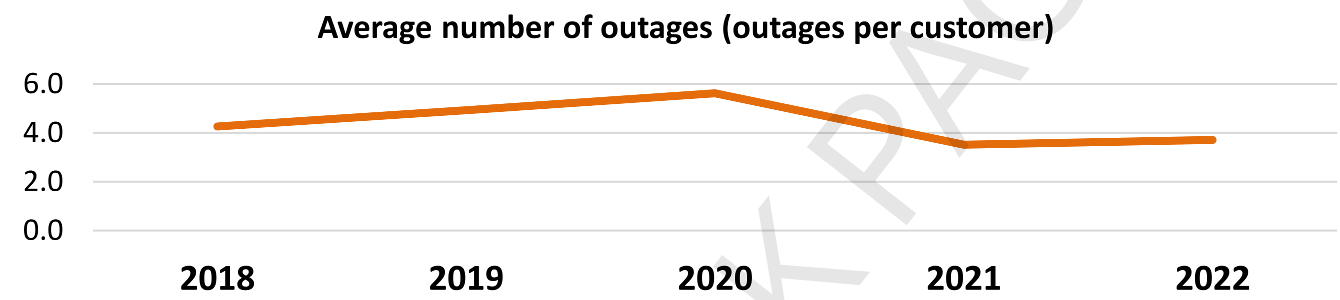
Background Context

Focus on Reliability

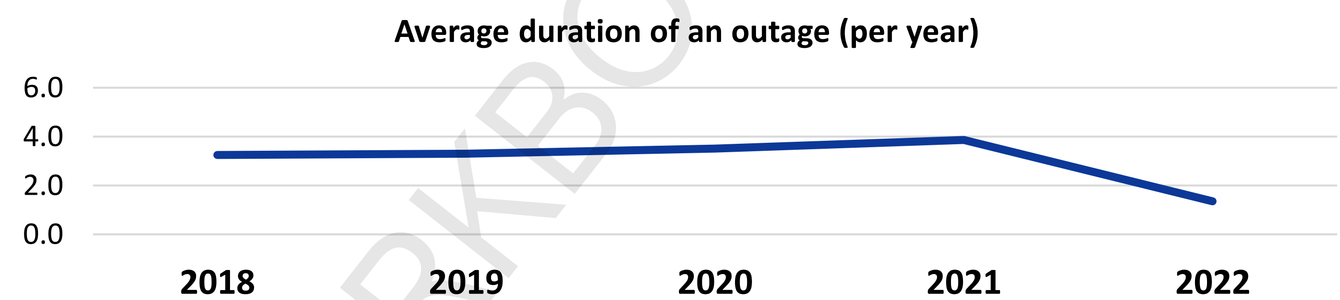
Since reliable electricity service is so important to customers, before we move on, we want to ask you about which specific areas you feel that Algoma Power should focus on over the next five years.

Algoma Power tracks both the **average number of power outages** per customer and **how long those interruptions last**.

Between 2018 and 2022, the typical Algoma Power customer has experienced about **4 and a half outages per year**.



Over the same period, the **average duration of an outage has been about 3 hours**. Meaning, when the power does go out, Algoma Power is typically able to restore power in about three hours.



It's important to keep in mind that these are system averages, and that your actual experience may be different.

- Generally speaking, the further away a customer is from the distribution substation, the more outages the customer will likely experience, as longer distribution lines have a higher probability of being damaged.
- Some customers connected to newer lines may not experience any outages, while others are experiencing more than the average number of outages each year.

The tables and figures above include outages related to extreme weather events and transmission loss of supply events (which Algoma Power has relatively lower ability to control).

Online Workbook

Number of Outages Experienced

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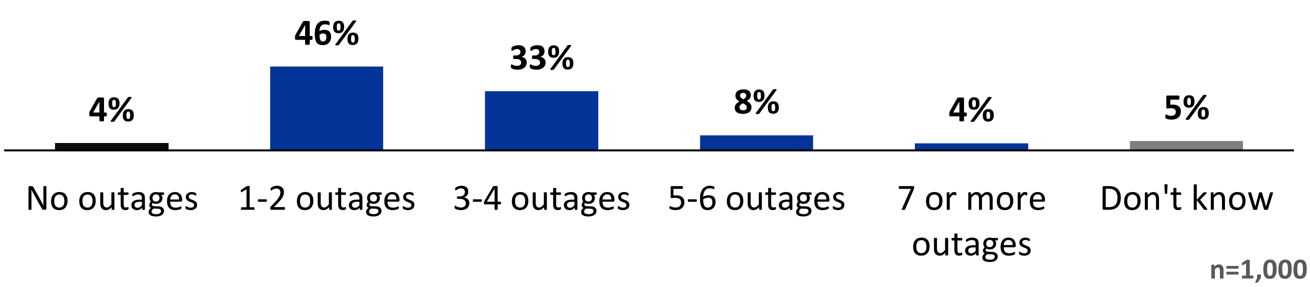
Q Have you experienced any power outages as an Algoma Power customer in the past 12 months which lasted longer than one minute?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
No outages	5%	2%	3%	4%	4%	5%	2%	6%	5%	3%
1-2 outages	48%	42%	51%	46%	53%	40%	45%	47%	48%	45%
3-4 outages	31%	37%	30%	32%	30%	35%	33%	33%	32%	33%
5-6 outages	8%	10%	6%	6%	9%	8%	10%	7%	8%	9%
7 or more outages	4%	5%	--	3%	3%	5%	5%	5%	3%	4%

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Online Workbook

Residential

Planning for the Future: 2025-2029 Rate Application

Background Context

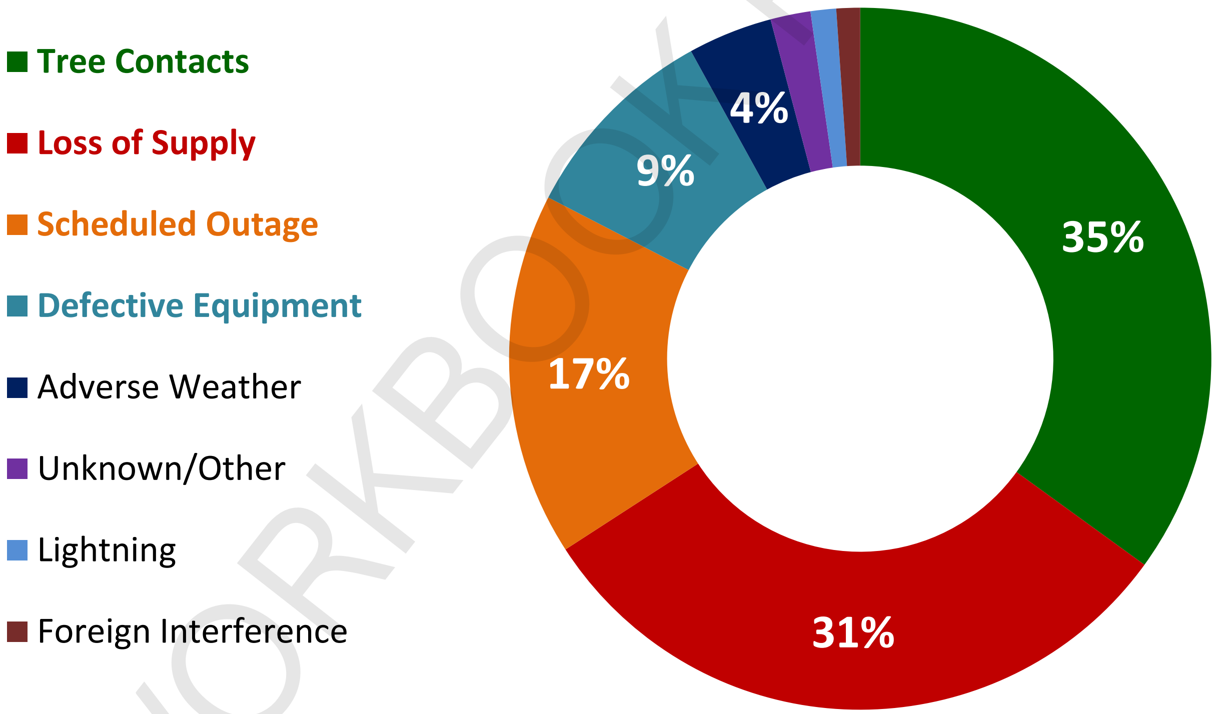
Focus on Reliability

Since 2018, 66% of all outages have been traced back to two causes – tree contacts (35%) and loss of supply from the transmission system (31%) operated by Hydro One.

While transmission system failures are largely out of the control of Algoma Power, there are investments that can be made to attempt to reduce the impacts of tree contacts, defective equipment, and even adverse weather.

Algoma Power has three service centres located in Desbarats, Wawa and Sault Ste. Marie that allow staff to respond to outages throughout the service territory.

Customer Outage Duration (Hours) by Cause 2018-2022



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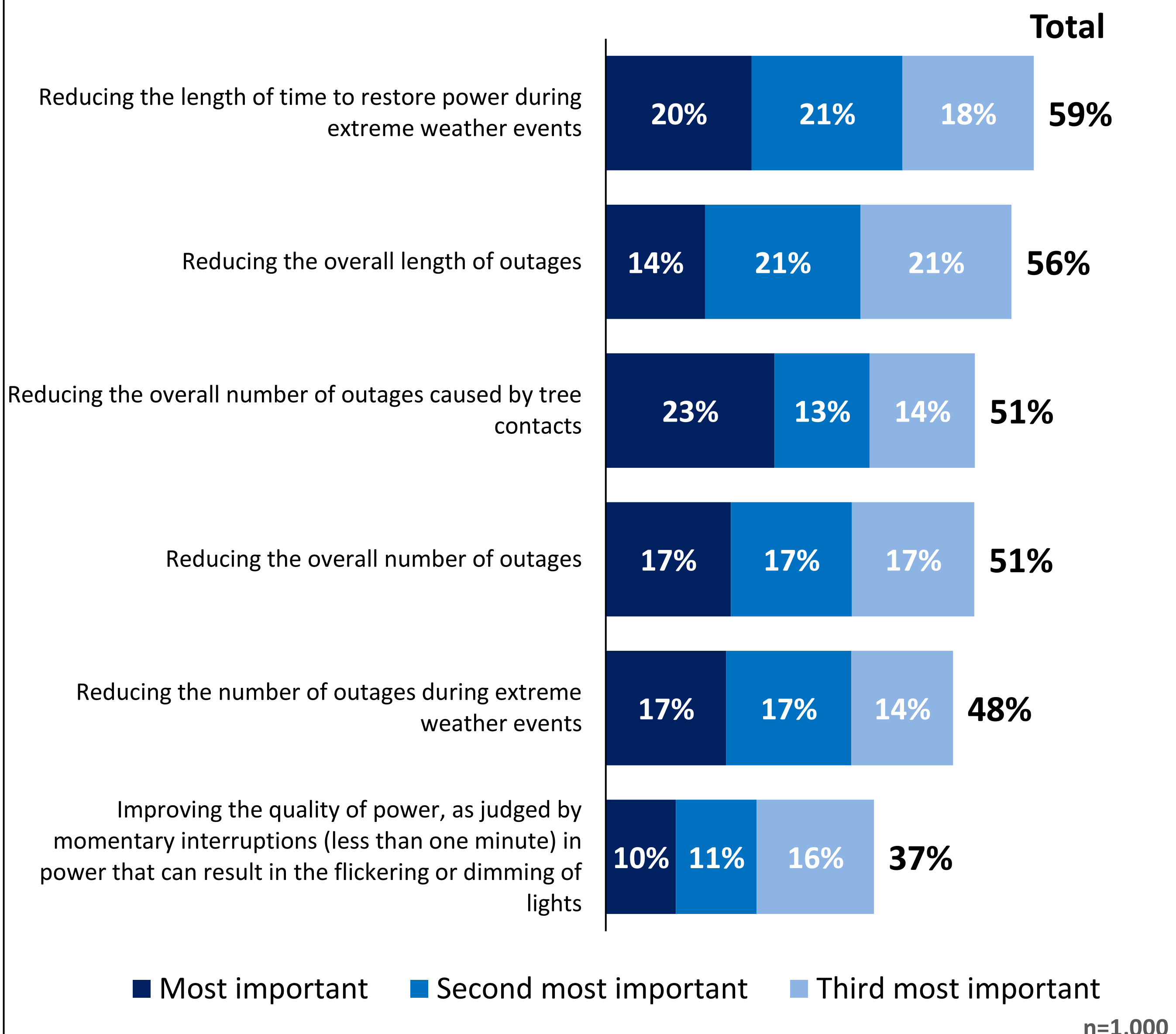
Reliability Priorities

Residential

Q

Since reliable electricity service is so important to customers, before we move on, we want to ask you about which specific areas you feel that Algoma Power should focus on over the next five years.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, and ending with the third most important.



Online Workbook

Reliability Priorities

Residential

% Total Important (top three)	Region			Consumption Quartiles			
	North/ West	East	Central	First	Second	Third	Fourth
Reducing the length of time to restore power during extreme weather events	57%	59%	69%	63%	58%	57%	56%
Reducing the overall length of outages	56%	58%	47%	55%	55%	61%	52%
Reducing the overall number of outages caused by tree contacts	49%	56%	45%	48%	52%	47%	55%
Reducing the overall number of outages	50%	54%	43%	49%	50%	51%	52%
Reducing the number of outages during extreme weather events	50%	39%	57%	47%	51%	48%	44%
Improving the quality of power, as judged by momentary interruptions	37%	35%	38%	37%	34%	35%	41%

% Total Important (top three)	LEAP Qualification		
	Yes	No <$52K	No >$52K
Reducing the length of time to restore power during extreme weather events	56%	57%	61%
Reducing the overall length of outages	56%	57%	56%
Reducing the overall number of outages caused by tree contacts	57%	49%	50%
Reducing the overall number of outages	45%	54%	49%
Reducing the number of outages during extreme weather events	51%	44%	48%
Improving the quality of power, as judged by momentary interruptions	35%	40%	36%

Online Workbook

Residential

Planning for the Future: 2025-2029 Rate Application

Algoma Power Background

How does Algoma Power propose to spend your money?

As mentioned, a portion of all Algoma Power customer bills goes towards operating and maintaining the electricity system. In addition to customer rates, some provincial funding also helps fund the budget which Algoma Power uses to operate its system. Over the five-year period from 2020 to 2024, this has resulted in a 5-year budget of **$146.7 million**.

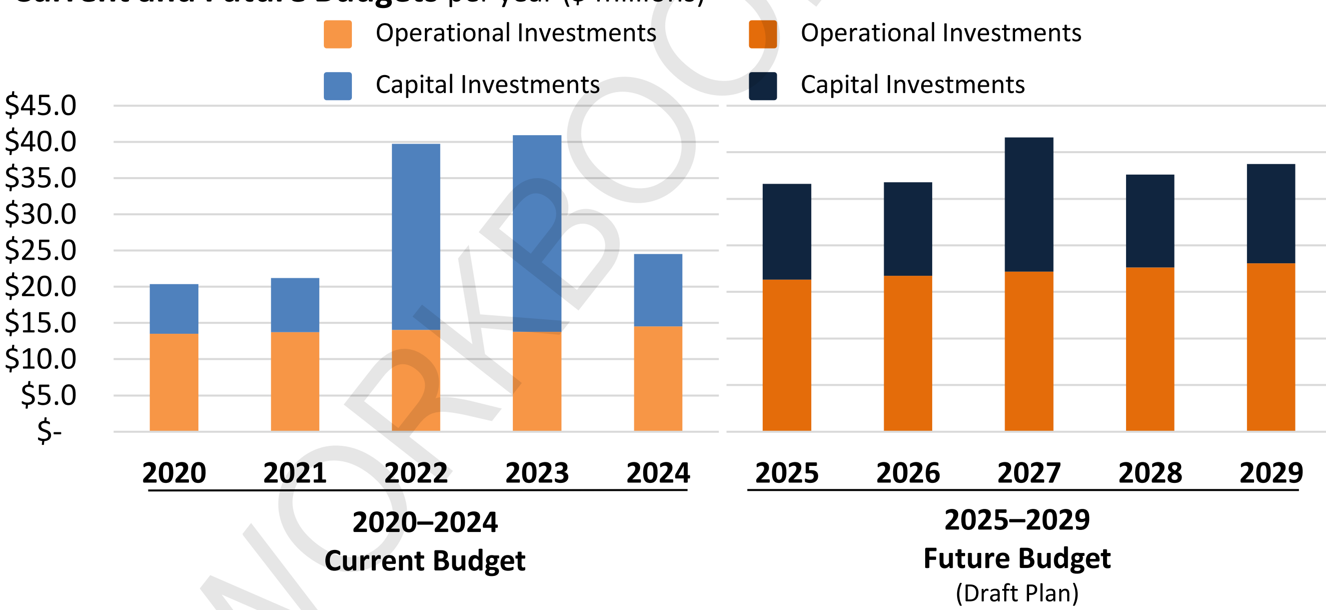
Between 2025 and 2029, Algoma Power is proposing to spend $141.3 million, a 3.7% decrease relative to the past five years.

To run the local grid and serve customers, Algoma Power manages two budgets:

1. A **capital investment** budget which pays for the cost of buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks, and computers.

2. An **operational investment** budget which pays for maintenance, testing, and operation of the equipment, vegetation management, as well as the staff needed to manage the grid and serve customers daily.

Current and Future Budgets per year ($ millions)



The current five-year budget of **$146.7 million** is based on the 2020–2024 plan approved by the OEB in a previous rate application. As mentioned earlier, this amount is funded by your 2020–2024 distribution rates.

The future five-year budget of **$141.3 million** is based on the 2025–2029 draft plan presented in this customer feedback survey. The final budget for this next rate period will be adjusted to reflect customer feedback collected through this engagement and will be subject to extensive OEB review before rates are set for 2025–2029.

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Planning for the Future: 2025-2029 Rate Application

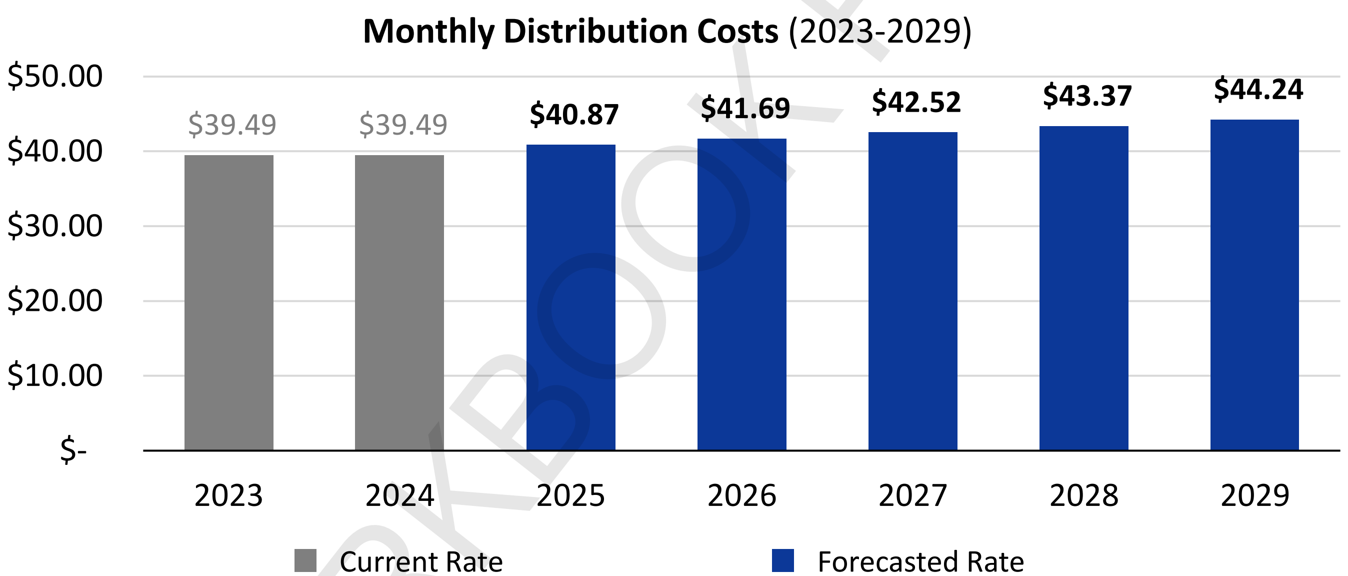
Algoma Power Background

How much will Algoma Power's draft plan cost me?

Your distribution rates are currently capped at **$39.49** by two government programs that are designed to bring the distribution costs for rural and remote customers more in line with what urban customers pay for distribution.

That means, unlike with most other electricity customers in Ontario, the amount Algoma Power spends to operate and maintain the system will not directly impact your bill, but it will for some other customers.

Under this cap, Algoma Power estimates that the distribution rate for a customer like yourself will increase by an average of 2% per year. Meaning that by 2030, assuming there are no changes to these government programs, the distribution portion of your bill will be $4.75 more than it is today.



Estimates are subject to change with factors including inflation, rate design updates, and pass through cost variations. A comprehensive budget for new 2030 projects/rates has not yet been developed.

Online Workbook

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Planning for the Future: 2025-2029 Rate Application

Algoma Power Background

What does Algoma Power want your feedback on?

Today, Algoma Power is seeking your input on its draft plan to ensure it is making the spending decisions that matter to you, the customer.

- The following sections of this workbook will explore 6 choices that Algoma Power needs to make to finalize its plans.
- Algoma Power will need to demonstrate to the OEB both what they heard from customers, as well as how they reflected your feedback in its plans.

How do I make choices?

Each choice has a summary of the options that Algoma Power is considering. In many cases, that includes options that would see Algoma Power ***spend less*** or ***more*** than what is currently being proposed.

- For each option you will be presented with to ***spend more*** or ***less***, Algoma Power has estimated what impact that would have on customer bills.
- These "rate impacts" are for illustrative purposes only. Because you are covered under **rural and distribution rate protections**, these "rate impacts" would not be reflected on your bill, but still represent the true cost of the choices.
- Following each question, you will also have an opportunity to provide additional optional feedback if you choose to.

Now, let's get started with Algoma Power's first decision related to **pole replacement**.

Making Choices (1 of 6)

Pole and Line Replacement

Background: As previously mentioned, Algoma Power has one of the largest (by geography) service territories of any electricity utility in Ontario. As such, Algoma Power operates and maintains 2,108 km of distribution line that is supported by 28,931 poles.

Each year, Algoma Power identifies and prioritizes pole lines for rebuilding based on their condition, age, and the consequences of their potential failure.

A recent assessment showed that about 3% or 972 of Algoma Power's poles were deemed to be in poor or very poor condition. Meaning, while rare, these 972 poles are at increased likelihood of "failing", which would likely cause a power outage for customers supplied by the line.

Current approach: Historically, Algoma Power has proactively replaced 500 poles per year or about 2% of all the poles in the system.

This approach has resulted, in part, in the current levels of reliability that you experience today. If Algoma Power gets too far behind on proactively replacing older poles, it can result in more outages and more costly reactive repairs. One pole can serve as many as 2,000 customers or as few as one.

2025-2029 proposed approach: Each year, as Algoma Power assesses a portion of its poles, some poles that were previously deemed to be in good condition are re-classified as poor or very poor. As such, over the next five years, Algoma Power is proposing to stay on the normal course and proactively replace 500 poles per year. Replacements are always prioritized based on condition and operational effectiveness.

Algoma Power also has an option to do more or less. When less is done, it increases the chances of more outages and more costly reactive repairs, but also pushes some of the associated costs further down the road. When more is done, it can result in some minor improvements to reliability, and get ahead of the curve at an additional cost.

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Choice 1: Pole and Line Replacement

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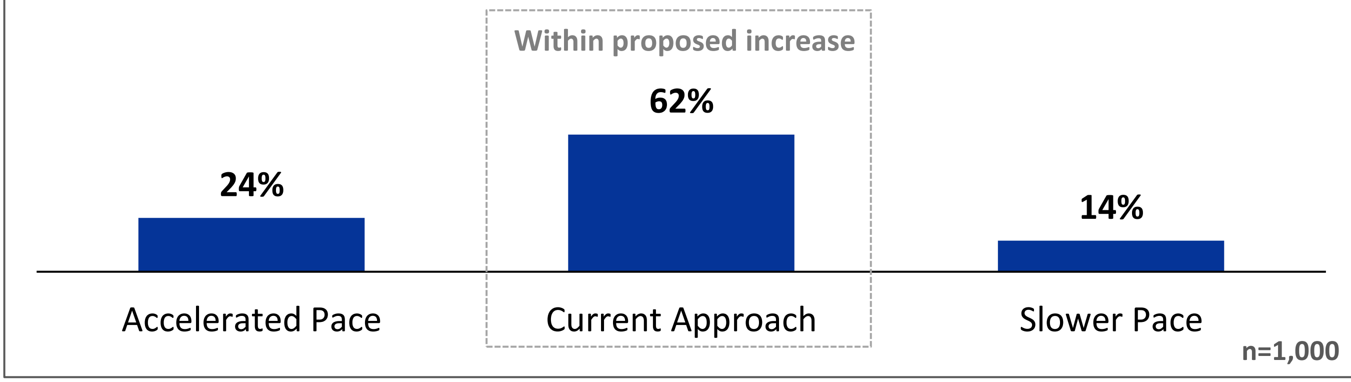
Which of the following options do you prefer?		
Option	Poles Replaced	Expected Outcome
Accelerated Pace ***$1.51*** *<u>more</u> on monthly bill by 2030*	Proactively replace <u>550</u> poles per year for the next five years.	• Increase the current pole replacement pace by 50 per year. • Potentially see reliability improvements due to decreased likelihood of pole failure resulting in outages. • "Get ahead" of pole replacement in subsequent years.
Current Approach *Within proposed rate increase*	Proactively replace <u>500</u> poles per year for the next five years.	• As this is the current approach, Algoma Power customers could expect to see similar reliability as it relates to poles (understanding that this is just one part of the system).
Slower Pace ***$1.51*** *<u>less</u> on monthly bill by 2030*	Proactively replace <u>450</u> poles per year for the next five years.	• Reduce the current pole replacement pace by 50 per year. • Potentially see an increased risk of failures resulting in outages. • Would reduce costs now but could result in increased costs in future years as more poles need to be replaced.
Additional Feedback (Optional)		

Online Workbook

Choice 1: Pole and Line Replacement

Residential

Q Which of the following options do you prefer?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Accelerated Pace	22%	28%	26%	22%	23%	24%	28%	21%	24%	27%
Current Approach	63%	60%	61%	65%	66%	59%	57%	63%	61%	61%
Slower Pace	15%	12%	12%	13%	11%	17%	15%	16%	15%	13%

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Online Workbook

Choice 1: Pole and Line Replacement

Residential

Q Which of the following options do you prefer?

Additional Comments	%
Instead of replacing poles, bury lines underground	1.4%
Willing to pay more for reliable service	0.8%
Lower rates/no increase/cost too high already/keep it affordable	0.7%
Prioritize replacement/depending on analysis of pole conditions	0.7%
Need more information/have questions	0.6%
Replace poles now to avoid future cost increases	0.5%
Replace as quick as possible	0.5%
Find efficiencies from within/upgrades should have been planned into budget	0.4%
Focus on infrastructure instead of replacing poles	0.3%
Possibility of acquiring old poles	0.3%
Only replace when needed	0.3%
Poles do not seem to be the issue	0.3%
Small price to pay/rate increase reasonable/get it done	0.2%
Reliability is acceptable	0.2%
More sustainable material for poles/not using wood/alternatives	0.2%
Focus on downed trees	0.1%
Other	0.2%
No answer	92.4%

Note: Only responses >0.1% shown

Online Workbook

Residential

Planning for the Future: 2025-2029 Rate Application

Making Choices (2 of 6)

Substation Rebuild

Background: Algoma Power owns and operates 9 substations. These substations, as pictured below, are used to "step down" the voltage supplied from Hydro One prior to distribution to customers. The equipment contained within these substations is critical and has a typical useful life of 50 years. The substation pictured below is in the town of Wawa and was built more than 50 years ago. Algoma Power has historically replaced substations as their age and condition requires it, for example a project is currently underway for a substation replacement in Bruce Mines this year.

The town of Wawa, with a population of 2,705 (2021 Census) is served by two substations. If one substation were to fail, the other would be able to back it up for a period, but not as a long-term solution.

As more customers start getting electric vehicles, solar panels, or just generally continue to use more electricity as an alternative to gas and other fuel sources, Algoma Power must right-size the substation transformer capacity to accommodate these increases in electrical demand. If electricity demand exceeds the transformer capacity, this could result in higher costs in the future.

Current approach: The lead time to replace the critical equipment within a substation can be anywhere from 1 to 3 years. In this case, if one of the substations servicing the town of Wawa were to fail, the entire community could be left without backup for years.

As such, when substation equipment is assessed in poor condition, Algoma Power typically starts planning to rebuild that substation, knowing that it can take years to plan, design and construct the rebuild.

2025-2029 proposed approach: In this upcoming plan, the question is not whether this substation in the town of Wawa needs to be rebuilt, but rather if Algoma Power uses this opportunity to update the equipment to prepare for growth in the community and the associated increase in electricity demand.

The "like-for-like" replacement option would see Algoma Power installing similar equipment to what has been in place for more than 50 years. This has served customers well for many years; however, in this case, Algoma Power is proposing to upgrade the equipment to be better prepared for community growth.

Online Workbook

Choice 2: Substation Rebuild

Residential

Which of the following options do you prefer?

Option	Transformer Size	Expected Outcome
Like-for-like capacity ***$0.17*** *less on monthly bill by 2030*	Procure and install a power transformer that is similar in capacity to the existing transformer.	Increased risk of premature transformer replacement as electricity uses increases as a result of overall home and business electrification.
50% capacity increase *Within proposed rate increase*	Procure and install a power transformer with a capacity that is 50% larger than the existing transformer.	Transformer capacity is sized in accordance with projected load increases associated with overall home and business electrification.
100% capacity increase ***$0.16*** *more on monthly bill by 2030*	Procure and install a power transformer with a capacity that is 100% larger than the existing transformer.	Larger transformer capacity would support increased electricity usage beyond the projected load increases.

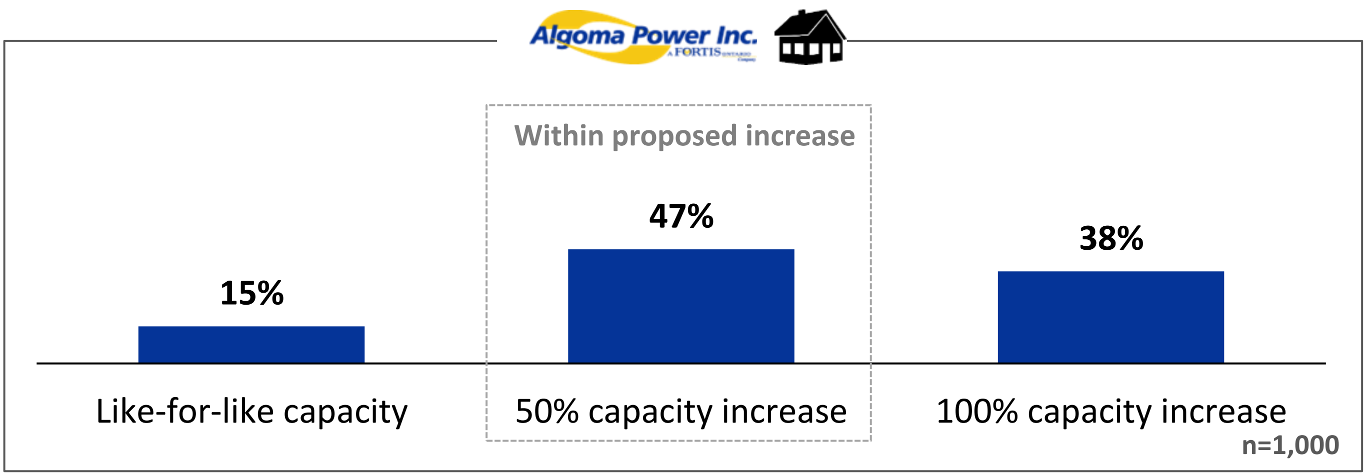
Additional Feedback (Optional)

Online Workbook

Choice 2: Substation Rebuild

Residential

Q Which of the following options do you prefer?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Like-for-like capacity	16%	15%	11%	15%	15%	16%	15%	26%	13%	13%
50% capacity increase	47%	48%	43%	52%	44%	48%	43%	43%	51%	47%
100% capacity increase	37%	37%	46%	33%	41%	36%	41%	31%	37%	40%

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Online Workbook

Choice 2: Substation Rebuild

Residential

Q Which of the following options do you prefer?

Additional Comments	%
Replace now to prepare for population growth/demands	2.0%
Skeptical of significant demand growth	1.0%
Support gradual approach/replace oldest first	0.7%
Depends on the growth in the community	0.7%
Need more information/have questions/not enough details	0.6%
The capacity increase is necessary	0.5%
Be proactive with the replacements	0.3%
Customers not qualified to decide/professional assessments required	0.2%
Not all customers should pay for specific upgrades/area based	0.2%
Costs need to be lower	0.2%
Government should cover costs	0.2%
Replace now to avoid future cost increases	0.1%
Lack of planning/foresight/costs should not be passed onto customers	0.1%
Small price to pay/rate increase reasonable/get it done	0.1%
Transition to EV/alternatives not practical in the area	0.1%
Other	0.5%
No answer	92.4%

Note: Only responses >0.1% shown

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Residential

Making Choices (3 of 6)

Voltage Conversion

Background: Much of Algoma Power's service territory is serviced by low-voltage distribution lines. These lines have much less capacity than modern lines. Meaning, that as demand for electricity increases, these lines struggle to distribute the constant flow of electricity that customers expect.

Current approach: These low-voltage distribution lines have historically served customers well, and in most cases will continue to do so. As such, upgrading these lines has not been a priority for Algoma Power in the past. However, in the future, increased demand for electricity means some of these lines are more likely to either fail or result in electricity flickering. When electricity flickers, it can result in homes and businesses having to re-set appliances or equipment, the clock on your stove, or other power quality issues. For local businesses, this can be particularly disruptive as machines and processes may be disrupted. This is more likely to occur in parts of the service territory where electricity demand increases more rapidly.

2025-2029 proposed approach: Starting in 2025, Algoma Power is proposing line upgrades to start mitigating some of the risks associated with these lower voltage lines.

Algoma Power has identified portions of the distribution system in the Goulais River and Batchawana Bay areas that serve 3,980 customers and are at risk of decreasing voltage reliability and power quality as the system load increases. To mitigate this risk, Algoma Power has proposed to convert the system voltage to a higher level.

Algoma Power is contemplating three pacing options to complete the voltage conversion in the Goulais River and Batchawana Bay areas - a minimum-level, mid-level and full-level voltage conversion plan. What isn't completed in this upcoming 5-year period will need to be completed in the next cycle. Doing more in the next 5-years will reduce the risk of equipment failure and power quality issues but increase the price you pay over this period. While the question requests your feedback on a project in a specific area, Algoma Power will take your feedback into account when looking at voltage conversion in other areas of the system.

Online Workbook

Choice 3: Voltage Conversion

Residential

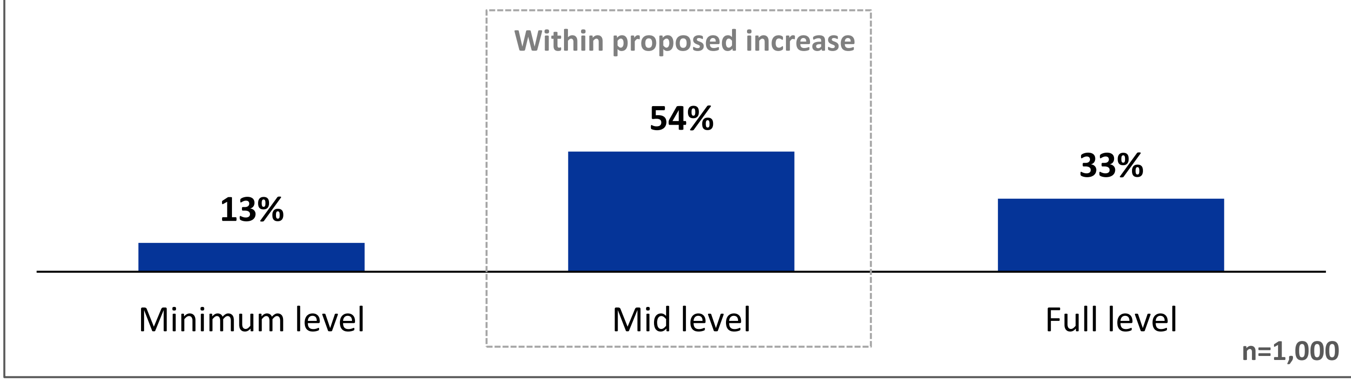
Which of the following options do you prefer?		
Option	% Upgraded	Expected Outcome
Minimum Level ***$0.13*** *less on monthly bill by 2030*	Upgrade and convert approximately 25% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 995 customers. • Lower cost now, but more will need to be deferred to the next cycle.
Mid Level *Within proposed rate increase*	Upgrade and convert approximately 50% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 1,990 customers. • Lower cost now, but some will need to be deferred to the next cycle.
Full Level ***$1.27*** *more on monthly bill by 2030*	Upgrade and convert approximately 100% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 3,980 customers. • Higher cost now, but none will need to be deferred to the next cycle.
Additional Feedback (Optional)		

Online Workbook

Choice 3: Voltage Conversion

Residential

Q Which of the following options do you prefer?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Minimum level	13%	12%	16%	12%	12%	15%	13%	24%	13%	11%
Mid level	55%	53%	52%	60%	55%	54%	47%	52%	53%	54%
Full level	32%	35%	32%	28%	33%	31%	40%	24%	34%	35%

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Online Workbook

Choice 3: Voltage Conversion

Residential

Q Which of the following options do you prefer?

Additional Comments	%
Willing to pay more for reliable service	0.8%
Be proactive with the replacements	0.7%
Replace as quick as possible	0.4%
Not all customers should pay for specific upgrades/area based	0.3%
Updating the system	0.2%
Lower rates/no increase/cost too high already/keep it affordable	0.2%
Don't know enough to make the decision/leave it to the experts	0.2%
Underground lines	0.2%
Government should cover costs	0.1%
Doesn't apply to me	0.1%
Skeptical of EV increases in the area	0.1%
Other	0.3%
No answer	96.4%

Note: Only responses >0.1% shown

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Making Choices (4 of 6)

Preparing for increased electricity demand

Background: Transformers are a critical piece of equipment that reduces the voltage of electricity before it enters your home or business. These transformers 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. That means a business using lots of electricity will generally have a larger transformer serving it than a typical 2- or 3-bedroom home.

But today, the "smaller" transformers that have historically served residential homes are increasingly struggling to keep up with increased demand. That means, today, when a transformer fails, it's replaced with a "larger" one to accommodate the increased demand for electricity.

Current approach: Currently, as is the case with most electricity utilities in Ontario, Algoma Power operates its transformers until they fail. When a transformer does fail, it typically takes between 2 and 4 hours to replace it and get the power back on for the customers that it serves.

However, as more customers start getting electric vehicles, solar panels, or just generally continue to use more electricity as an alternative to gas and other fuel sources, Algoma Power is projecting that more and more transformers will need to be upgraded to accommodate these changes. If demand increases quicker than Algoma Power can upgrade transformers, this could lead to transformers failing more frequently.

2025-2029 proposed approach : Over the next five years, Algoma Power is proposing a similar approach to what has been done in the past. That is, run the transformers until they fail and replace them with "larger" transformers to accommodate increased electricity usage.

However, depending on what customers value, Algoma Power is considering a new program that would identify areas in the community with the greatest increase in demand, and proactively swapping out the smaller transformers for larger ones to avoid potential failures. This new program wouldn't have a significant impact on current reliability but would help ensure that when the time comes, customers will have access to the electricity they want to meet their growing and changing needs.

If demand for electricity from customers increases more rapidly than expected, Algoma Power may have to cancel or delay other planned projects to accommodate these newer transformers that aren't budgeted for.

Online Workbook

Residential

Choice 4: Preparing for increased electricity demand

Which of the following options do you prefer?

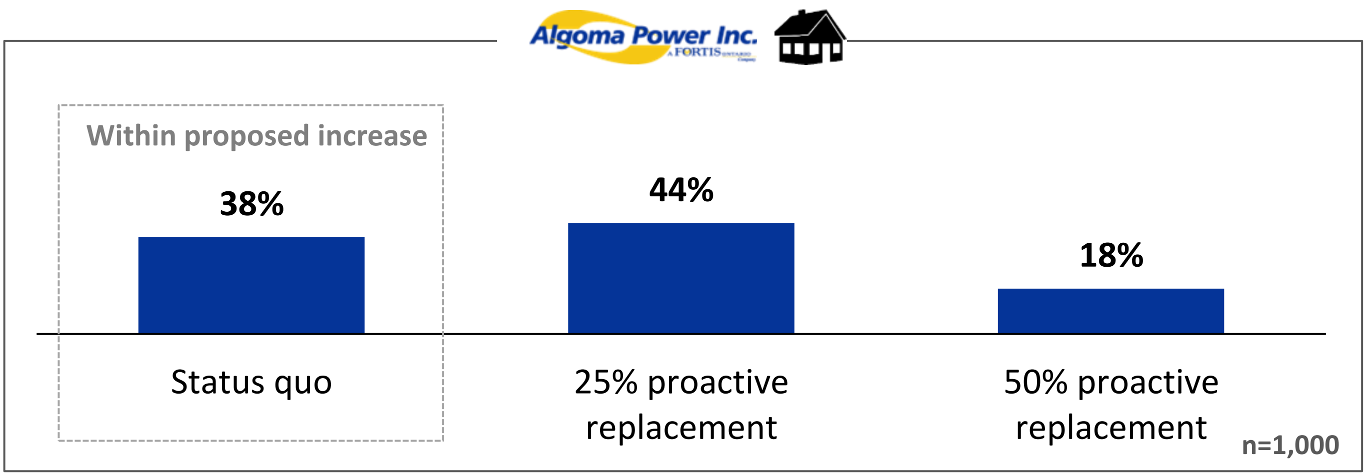
Option	Transformers Replaced	Expected Outcome
Status Quo *Within proposed rate increase*	Based on historical data, reactively replace approximately 12 transformers per year as they fail.	• Maximize the useful life of current transformers. • Potential for higher levels of unplanned outages due to transformer failures.
25% proactive replacement ***$0.77** more on monthly bill by 2030*	Proactively replace 275 transformers by 2029 (55 per year).	• Accelerate transformer changes to meet anticipated demand for electricity. • Potential for reduced rate of unplanned outages due to transformer failures.
50% proactive replacement ***$1.53** more on monthly bill by 2030*	Proactively replace 550 transformers by 2029 (110 per year).	• Further accelerate transformer changes to meet anticipated demand for electricity. • Potential for reduced rate of unplanned outages due to transformer failures.
Additional Feedback (Optional)		

Online Workbook

Residential

Choice 4: Preparing for increased electricity demand

Q Which of the following options do you prefer?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Status quo	41%	36%	32%	39%	36%	41%	37%	46%	37%	36%
25% proactive replacement	44%	43%	45%	46%	47%	42%	40%	35%	45%	45%
50% proactive replacement	16%	21%	22%	15%	17%	17%	23%	18%	18%	19%

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Online Workbook

Residential

Choice 4: Preparing for increased electricity demand

Q Which of the following options do you prefer?

Additional Comments	%
Only replace when needed	0.9%
Not all customers should pay for specific upgrades/area based	0.7%
Be proactive with the replacements	0.6%
Transition to EV/alternatives not practical in the area	0.5%
Need more information/have questions	0.5%
Find efficiencies from within/upgrades should have been planned into budget	0.4%
Small price to pay/rate increase reasonable/get it done	0.2%
Lower rates/no increase/cost too high already/keep it affordable	0.2%
Greener alternatives/environmental implications	0.2%
Length of outage is fine	0.1%
Biased survey/designed to illicit specific responses	0.1%
Other	0.3%
None	95.2%

Note: Only responses >0.1% shown

Online Workbook

Residential

Planning for the Future: 2025-2029 Rate Application

Making Choices (5 of 6)

Automated "intelligent" switches

Background: Technology has changed the way that Algoma Power can manage and monitor the distribution system.

Strategically located automated switches can help Algoma Power remotely monitor and trace power outages and re-route electricity from a control room rather than sending a repair crew to patrol the lines. This is made possible by both a) a physical automated "switch" often mounted on a pole that allows Algoma Power to easily locate an outage and b) computer software that allows that automated "switch" to be flipped remotely and re-route power.

Current Approach: Currently, Algoma Power has strategically employed "intelligent" automated switches in various parts of its service territory. When an outage occurs in an area without this automated technology, it can take crews between 4 and 8 hours to locate the issue, fix it and restore power.

By installing only an automated switch in an area, outage restoration times can be reduced by nearly half.

When an automated switch and the accompanying software is installed, an outage that would otherwise take 4-8 hours to restore could be reduced to less than one hour.

As with anything, there are costs associated with rolling out this technology more broadly.

2025-2029 proposed approach: In its current draft plan, Algoma Power is proposing to roll out the installation of automated switches and the associated software along a major line that serves approximately 6,200 customers east of Sault Ste. Marie.

That said, depending on customer feedback, Algoma Power could continue with the status quo and install no new additional switches, or they could defer some of the software upgrades to a later period, therefore reducing the bill impact for customers.

Online Workbook

Residential

Choice 5: Automated "intelligent" switches

Which of the following options do you prefer?

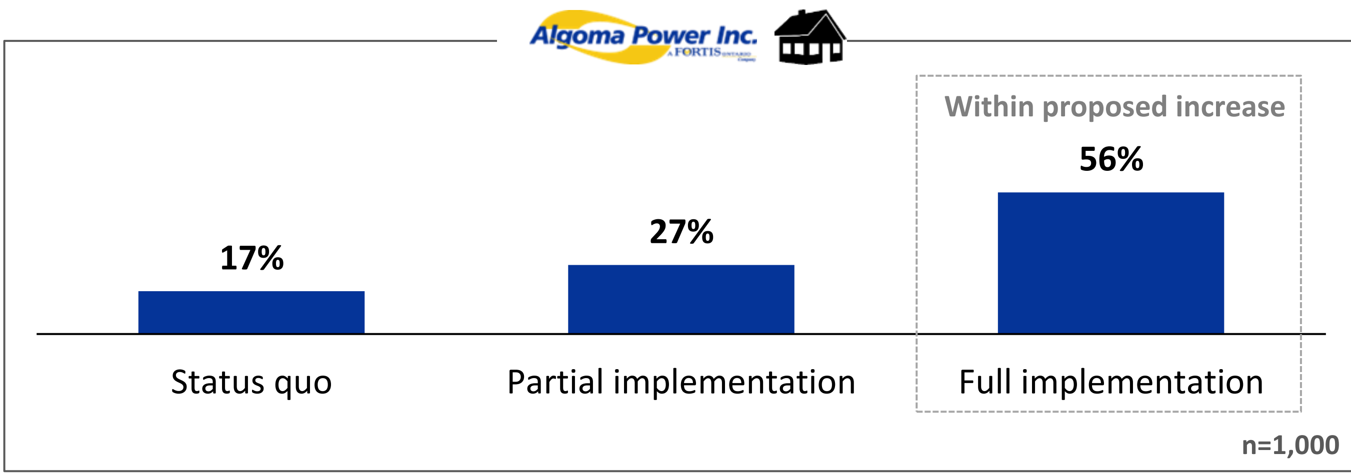
Option	Automated Switches	Expected Outcome
Status Quo ***$0.67*** *<u>less</u> on monthly bill by 2030*	No additional automated switches or software purchased and installed.	Across this stretch of the system, Algoma Power continues to manually locate outages and restore power, typically taking between 4 and 8 hours on average.
Partial Implementation ***$0.33*** *<u>less</u> on monthly bill by 2030*	• Install remotely controllable automated switches on a major line east of Sault Ste. Marie that serves 6,200 customers. • Defer the purchase and installation of software to 2030 and beyond.	Across this stretch of line, Algoma Power will be able to remotely locate an outage, improving average estimated restoration times by about 50%.
Full Implementation *Within proposed rate increase*	• Install both the remotely controllable automated switches and associated software on the major line east of Sault Ste. Marie. • Once software has been installed once, it can be rolled out across the system in the future.	Same benefits of partial implementation, however, outage restoration times are reduced even further because power can be restored remotely.
Additional Feedback (Optional)		

Online Workbook

Choice 5: Automated “intelligent” switches

Residential

Q Which of the following options do you prefer?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Status quo	20%	12%	16%	16%	13%	19%	19%	23%	17%	15%
Partial implementation	28%	27%	27%	29%	31%	27%	23%	22%	28%	26%
Full implementation	53%	62%	57%	56%	56%	53%	58%	55%	55%	59%

Online Workbook

Choice 5: Automated "intelligent" switches

Residential

Q Which of the following options do you prefer?

Additional Comments	%
Willing to pay more for reliable service	0.8%
Lower rates/no increase/cost too high already/keep it affordable	0.4%
Try to prevent job losses	0.3%
Encourage implementation of new technology	0.2%
Be proactive with the replacements	0.2%
Need more information/have questions	0.2%
Only those customers/areas affected should pay the cost	0.1%
Against the installation of automated switches	0.1%
Other	0.2%
No answer	97.5%

Note: Only responses >0.1% shown

Online Workbook

Residential

Planning for the Future: 2025-2029 Rate Application

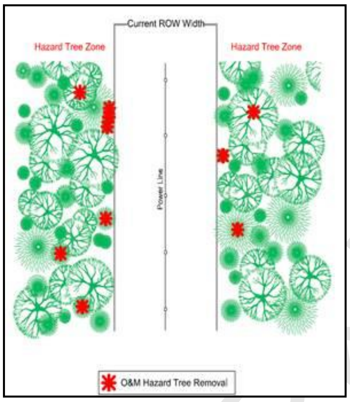
Making Choices (6 of 6)

Vegetation Management

Background: Between 2018 and 2022, tree contacts have contributed to 35% of all customer outages, as measured by the total number of hours without power. While tree caused outages have significantly declined over the years through Algoma Power's Vegetation Management Program (VMP), trees remain the biggest contributor to customer power outages. As 85% of Algoma Power's powerlines have a treed (forested) edge, the most common cause of power interruptions are tree related and require crews to be dispatched to make repairs and restore power.

Current approach: Algoma Power continues to manage vegetation in proximity to powerlines to reduce the risk of tree exposure and limit the occurrence of tree caused outages. Work activities including trimming and removal of trees are part of scheduled maintenance practices used to manage vegetation (trees and brush) that can fall or grow into the powerlines.

To mitigate these risks, Algoma Power's VMP takes a preventative approach using condition assessments to determine priority work. Priority work is largely based on tree health, growth, and impact to service interruptions. To date, priority work is a main contributor to the reduction in tree caused outages, particularly within the hazard tree zone (see diagram below).



2025-2029 proposed approach: In its current draft plan, Algoma Power is proposing to continue with its historical approach of preventative maintenance to reduce the potential of tree caused outages across the service territory. While this would result in similar reliability outcomes to the past, the rapid improvements to reliability would likely slow down.

To further reduce costs, Algoma Power is also considering reducing the frequency of assessing and removing declining trees that occurs within this "hazard tree zone". Reducing this assessment would ultimately increase the risk that a tree in poor condition is missed and could therefore come into contact with a powerline.

On the other hand, Algoma Power could also increase its assessment in this area, further reducing the likelihood of a tree contact, even relative to today's standards. This is where Algoma Power wants to hear from you.

Online Workbook

Choice 6: Vegetation Management

Residential

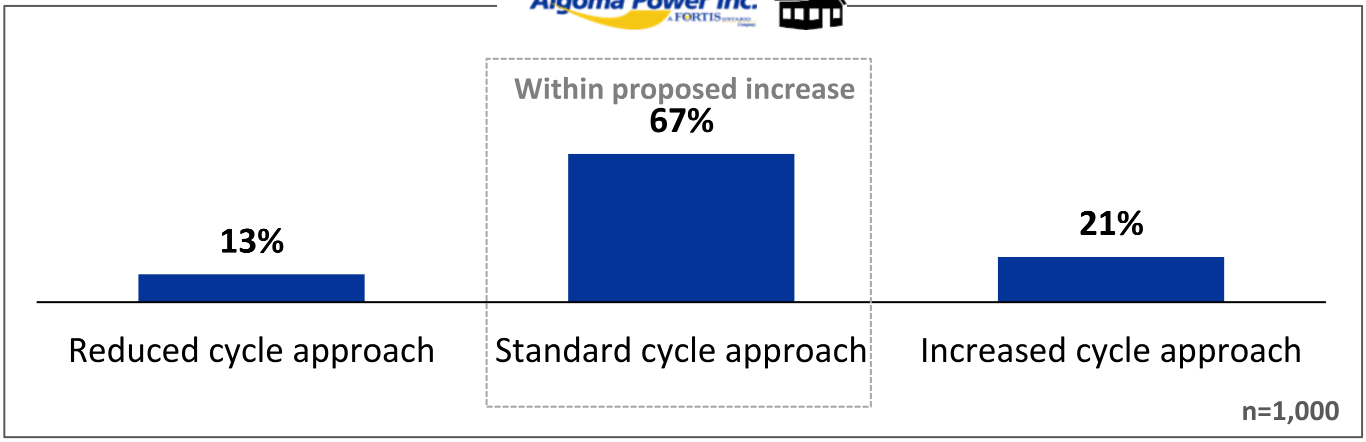
Which of the following options do you prefer?		
Option	Approach	Expected Outcome
Reduced Cycle Approach ***$1.43** <u>less</u> on monthly bill by 2030*	Reduce the level of "hazard tree zone" monitoring by 300 km per year.	• Increased exposure of hazard trees to the powerlines • Potential for decreased reliability resulting from increased exposure of the hazard trees.
Standard Cycle Approach *Within proposed rate increase*	Status Quo, continue with historical approach.	• Similar trend in reliability performance relative to the past 5 years
Increased Cycle Approach ***$1.43** <u>more</u> on monthly bill by 2030*	Increase the level of "hazard tree zone" monitoring by 300 km per year.	• Decreased exposure of hazard trees to the powerlines • Potential for increased reliability performance resulting from reduced exposure of the hazard trees.
Additional Feedback (Optional)		

Online Workbook

Choice 6: Vegetation Management

Residential

Q Which of the following options do you prefer?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Reduced cycle approach	13%	12%	10%	13%	9%	14%	14%	17%	9%	11%
Standard cycle approach	68%	66%	62%	68%	70%	66%	63%	62%	67%	69%
Increased cycle approach	18%	22%	29%	20%	20%	20%	23%	21%	24%	20%

Online Workbook

Choice 6: Vegetation Management

Residential

Q Which of the following options do you prefer?

Additional Comments	%
Preventative maintenance of trees helps with outages	1.5%
Consider other approaches (tree topping)	1.4%
Against healthy tree removals/cutting	1.4%
Bury lines underground	0.7%
Customers to alert Algoma Power of tree issues/hazards	0.5%
Lower rates/no increase/cost too high already/keep it affordable	0.3%
Willing to pay more for reliable service	0.2%
Find efficiencies from within/upgrades should have been planned into budget	0.1%
Other	0.2%
No answer	93.8%

Note: Only responses >0.1% shown

Impact of Choices

Do You Want to Change Your Choices?

Residential

Impact of Choices

Investment alternative summary

Throughout this workbook, you have been asked about 6 key choices. Below is a summary of your answers to those questions.

At the bottom of this page, you will find the cumulative impact of your choices.

These “rate impacts” are for illustrative purposes only. Because you are covered under rural and distribution rate protections, these “rate impacts” would not be reflected on your bill, but still represent the true cost of the choices.

Having seen the total impact of your choices, please review your answers and change your responses if you desire; the impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you’ve reached the best balance for you.

Residential Customer Bill Impact Change and Magnitude of Bill Impact **(MEAN)**

Range of Impacts

-$3.91 to +$5.90

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 **$5.90 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 **$3.91** less per month by 2030 when compared to the draft plan.

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Impact of Choices

Do You Want to Change Your Choices?

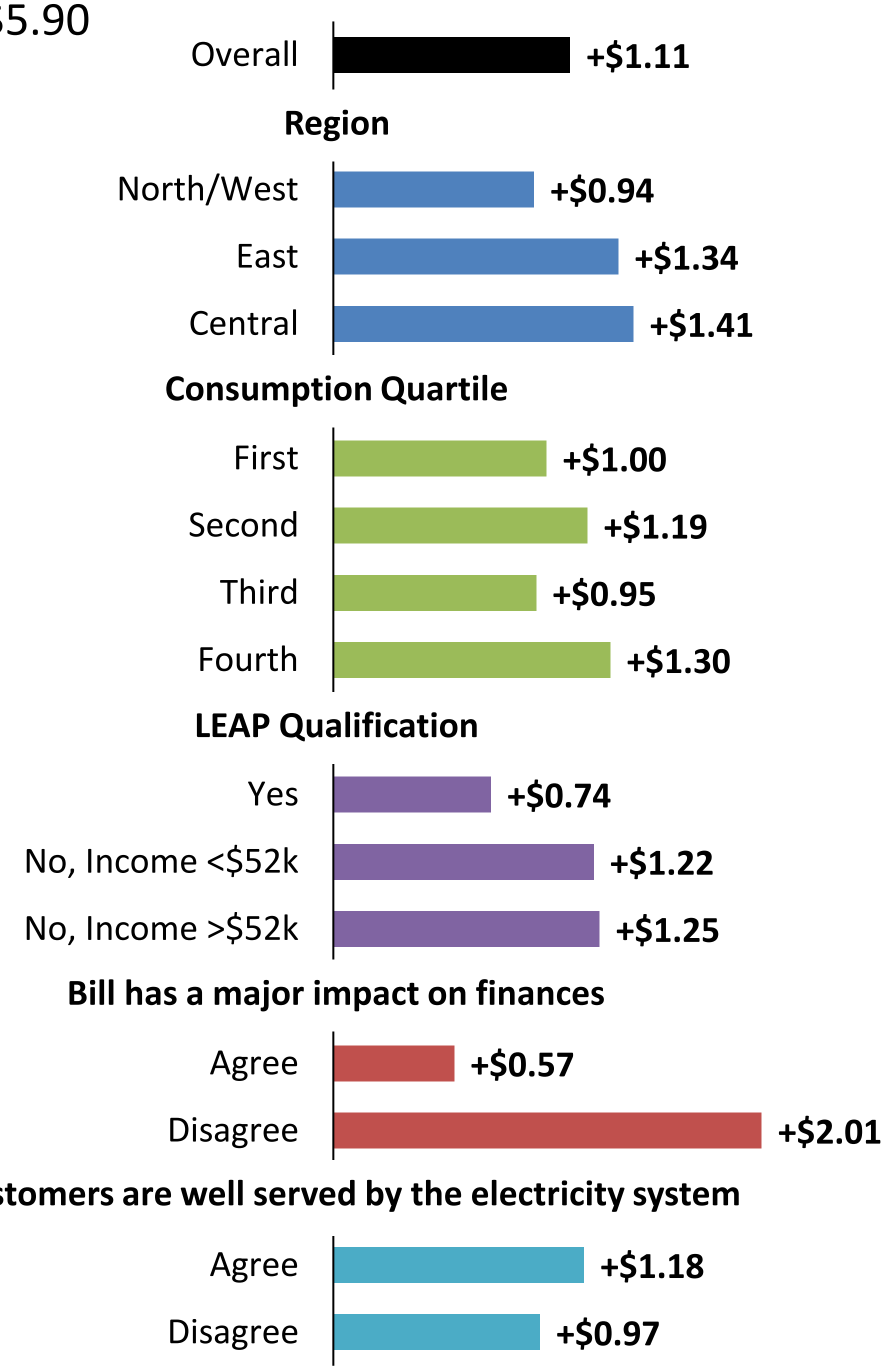
Residential

Impact of Choices

Investment alternative summary

Residential Customer Final Magnitude of Bill Impact BY key segments **(MEAN)**

Range of Impacts
-$3.91 to +$5.90

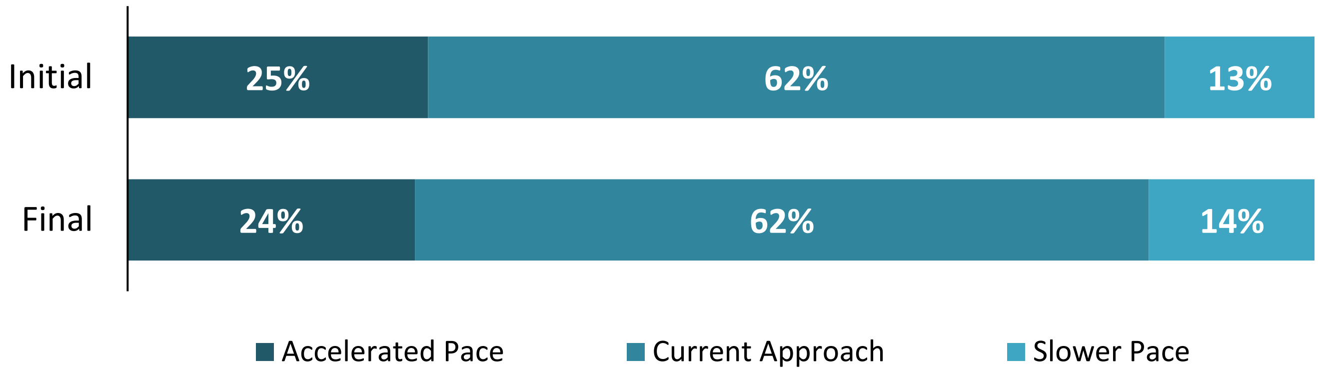


Making Choices

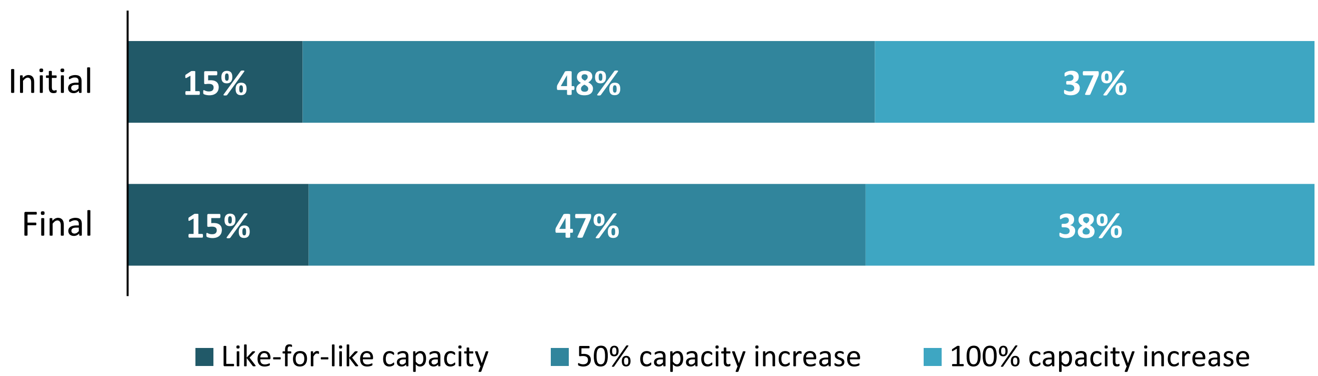
Impact of Choices

Residential

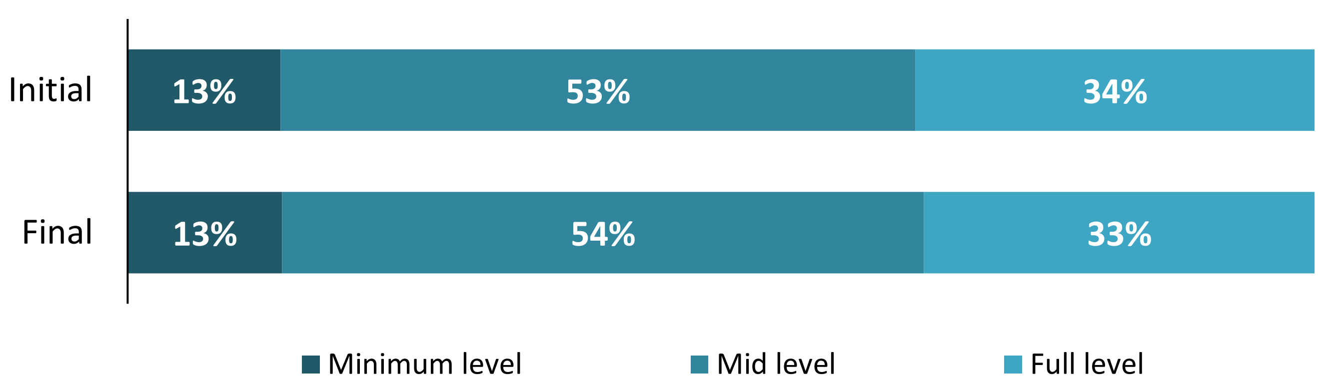
Pole and Line Replacement



Substation Rebuild



Voltage Conversion

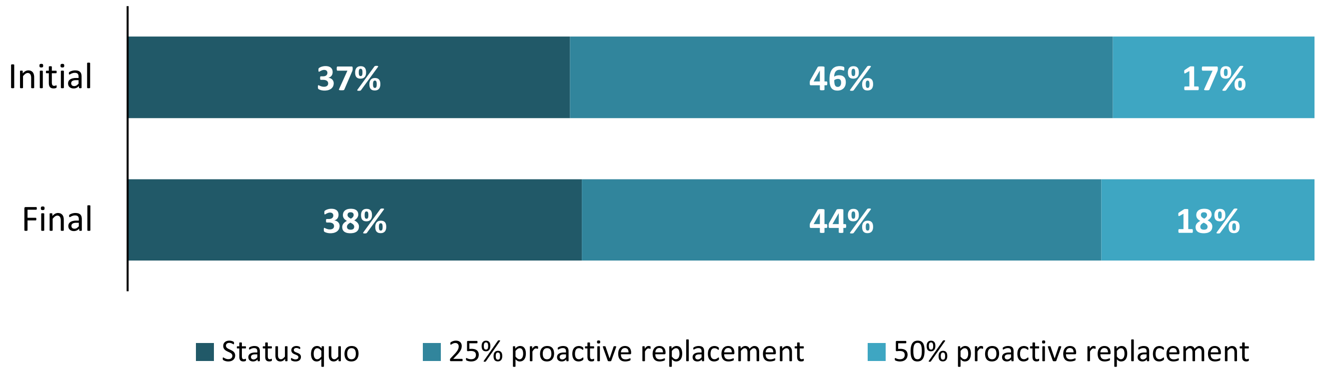


Making Choices

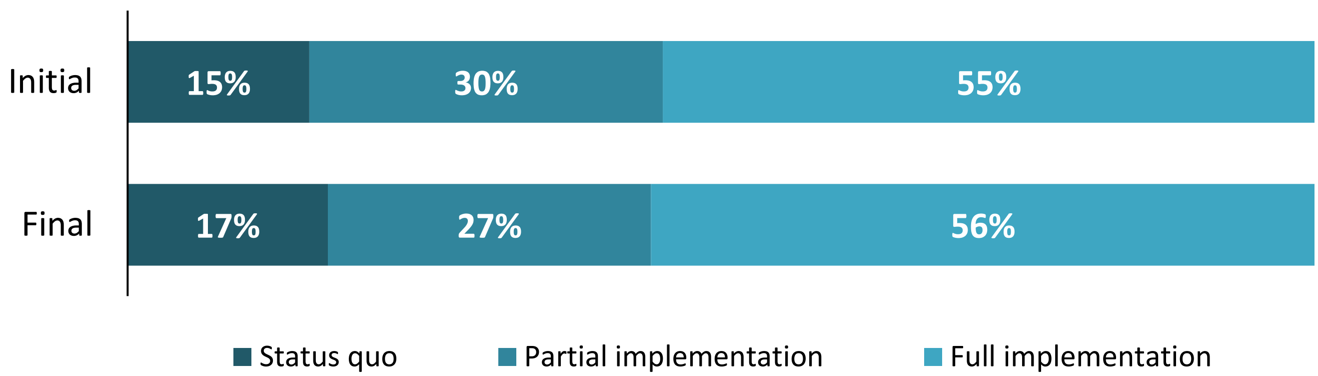
Impact of Choices

Residential

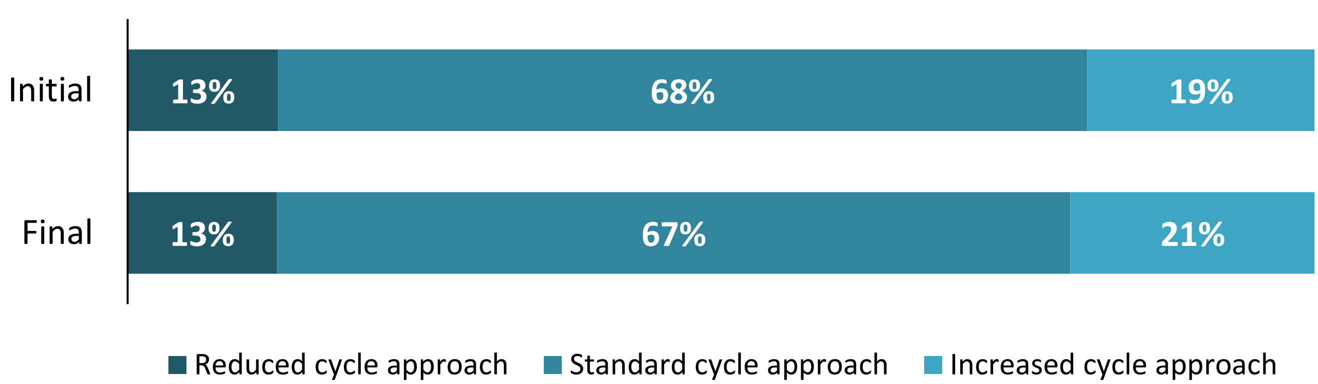
Preparing for increased electricity demand



Automated “intelligent” switches



Vegetation Management



INNOVATIVE RESEARCH GROUP

Online Workbook

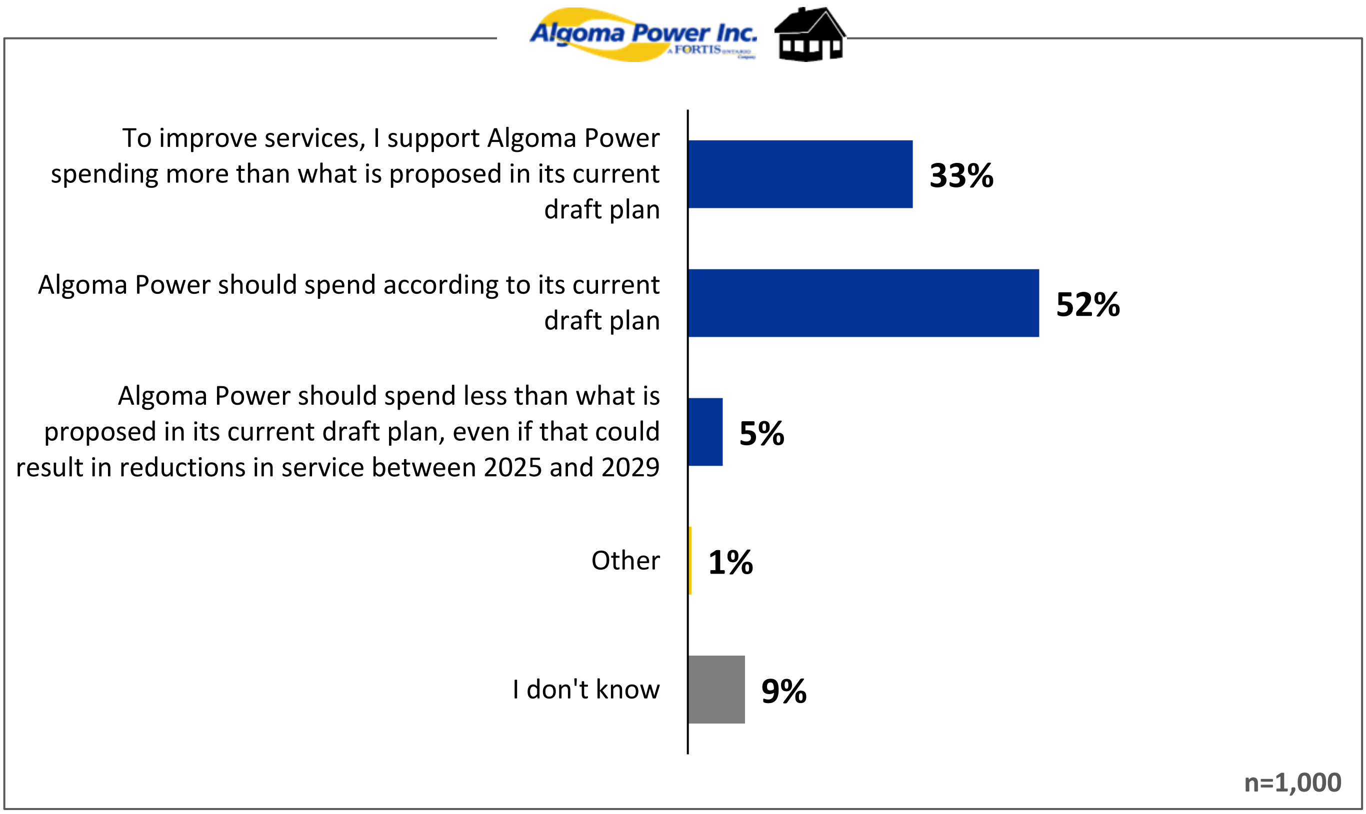
Overall Plan Evaluation

Residential

Q

Algoma Power has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Algoma Power would like to know how you feel about the draft plan.

Considering what you have learned about Algoma Power's 2025–2029 draft plan, which of the following best represents your point of view?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Spend more	30%	37%	43%	30%	35%	37%	30%	30%	35%	37%
Spend according to plan	55%	47%	48%	52%	49%	53%	52%	52%	49%	53%
Spend less	6%	6%	--	4%	3%	5%	4%	4%	3%	5%

Online Workbook

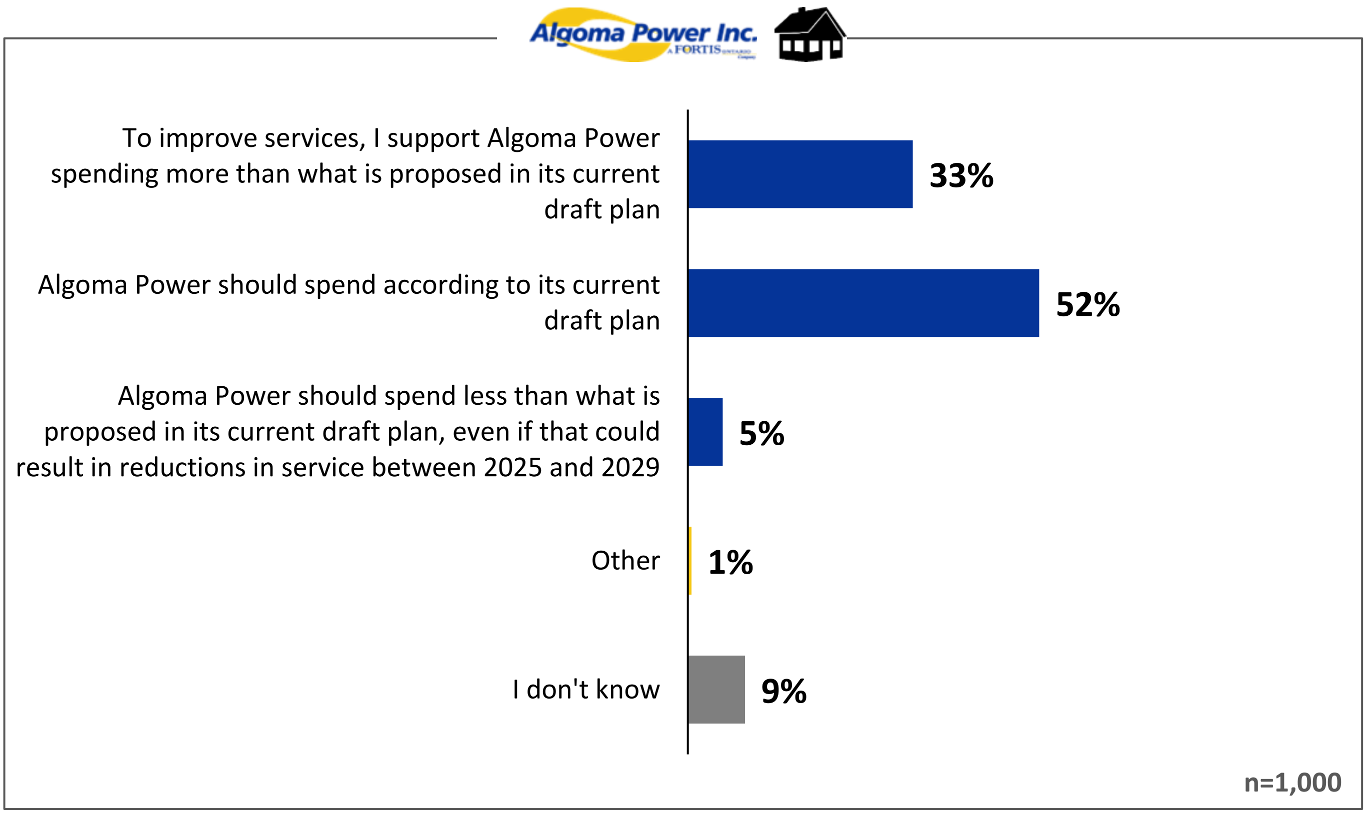
Overall Plan Evaluation

Residential

Q

Algoma Power has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Algoma Power would like to know how you feel about the draft plan.

Considering what you have learned about Algoma Power's 2025–2029 draft plan, which of the following best represents your point of view?



	Bill has a major impact on finances		Customers are well served by the electricity system	
	Agree	Disagree	Agree	Disagree
Spend more	24%	47%	34%	27%
Spend according to plan	56%	46%	52%	53%
Spend less	8%	1%	5%	7%

Online Workbook

Residential

Final Comments about Algoma Power's draft plan for 2025–2029

Q Do you have any final comments regarding Algoma Power's draft plan for 2025–2029 and the proposed rate increase?

Additional Comments	%
Draft plan/approach is reasonable	1.6%
Be proactive/responsible/prepare for the future/improve grid	1.5%
Support the proposed rate increase/investments are necessary	1.5%
Affordability/Keep cost low	1.3%
Satisfied with service/Great work	1.1%
Focus on environmental/sustainable concerns/practices	0.9%
Concerns/skeptical about the draft plan/choices/survey	0.9%
Concerns of increases due to the high cost of living/inflation	0.8%
Need more information/answer questions/concerns	0.7%
Government should cover costs/contribute towards proposed rate increases	0.7%
Appreciate informing/educating customers of the plan/approaches/choices	0.6%
Decrease distribution/delivery charges/high rates/costs	0.3%
Algoma Power will do what they want/won't listen to customers	0.3%
Inform customers before cutting/removing trees	0.2%
Discounts for seniors/low-income/long time customers	0.2%
Increases should improve service, not CEO's/upper management salaries	0.2%
Find efficiencies from within/upgrades should have been planned into budget	0.2%
Concerns with seasonal rates/same rate across all customers	0.1%
Be transparent/communicative with customers about the proposed rate increases	0.1%
Other	1.1%
None	85.8%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

INNOVATIVE RESEARCH GROUP

Residential Customers

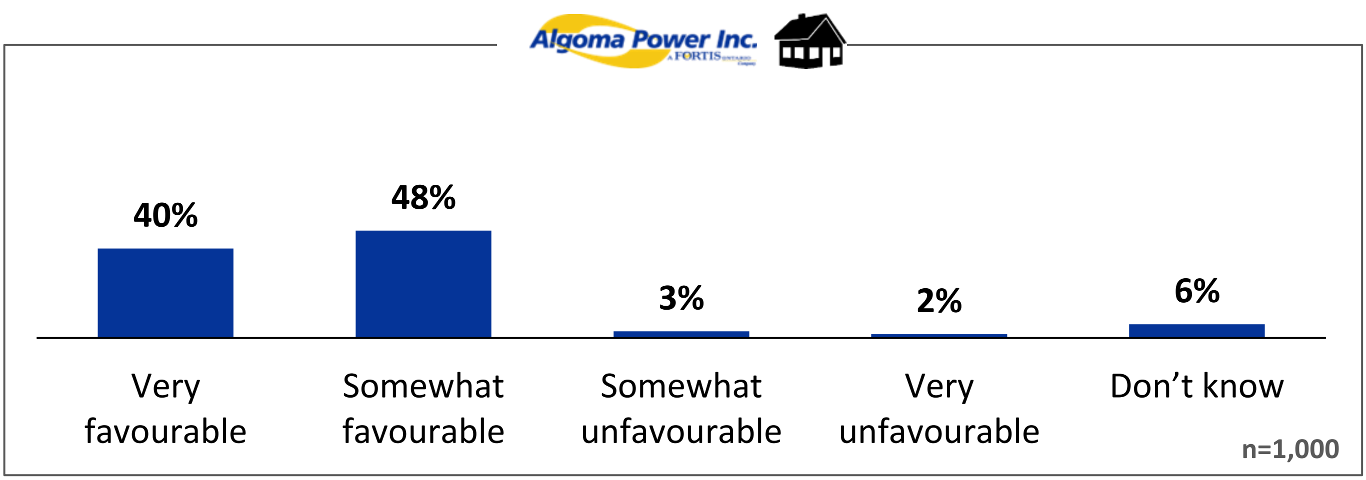
Workbook Diagnostics

Online Workbook

Workbook Impression

Residential

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Very favourable	40%	41%	41%	43%	44%	35%	39%	40%	36%	45%
Somewhat favourable	49%	48%	49%	50%	46%	47%	50%	46%	54%	46%
Somewhat unfavourable	3%	3%	3%	3%	3%	4%	2%	5%	4%	3%
Very unfavourable	2%	2%	--	2%	1%	2%	2%	2%	--	2%
Don't know	6%	6%	8%	2%	5%	11%	7%	8%	6%	5%
Favourable (Very + Somewhat)	**89%**	**89%**	**90%**	**93%**	**91%**	**83%**	**89%**	**86%**	**90%**	**91%**
Unfavourable (Very + Somewhat)	**5%**	**4%**	**3%**	**5%**	**4%**	**7%**	**4%**	**6%**	**4%**	**4%**

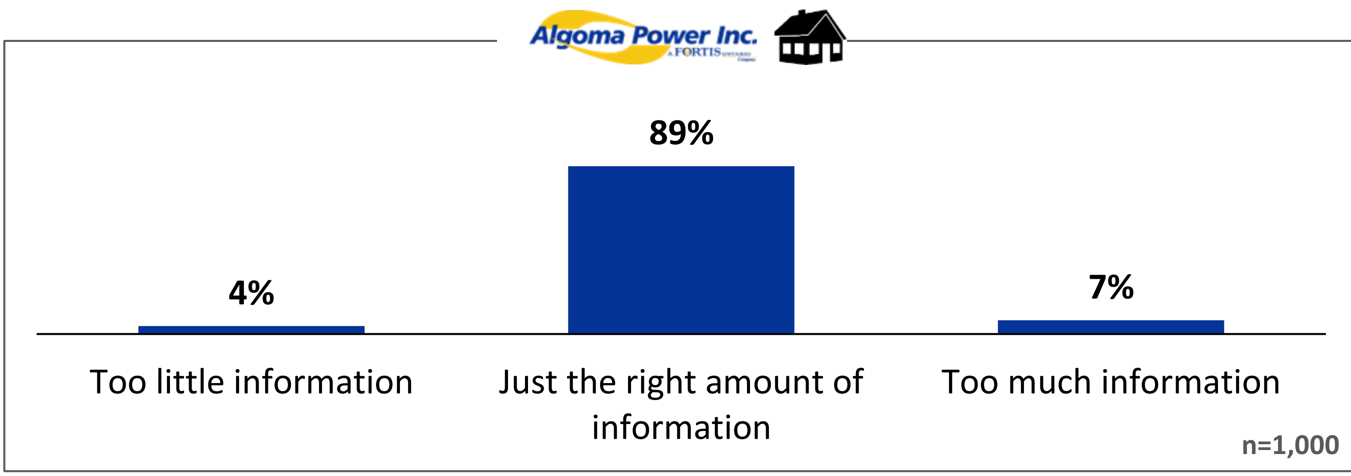
INNOVATIVE RESEARCH GROUP

Online Workbook

Amount of Information

Residential

Q In this customer engagement, do you feel that Algoma Power provided too much information, not enough, or just the right amount?



	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Too little information	4%	4%	4%	4%	4%	6%	3%	4%	3%	3%
Just the right amount	88%	89%	91%	90%	91%	85%	89%	90%	92%	89%
Too much information	8%	7%	5%	6%	6%	9%	8%	6%	5%	8%

Online Workbook

Content Missing from Engagement

Residential

Q Was there any content missing that you would have liked to have seen included in this customer engagement?

Additional Comments	%
Breakdown/clear explanation of charges/rates/comparison to other utilities	1.2%
Survey issues - too long/too many words/complicated language/more videos	1.1%
More information/details/statistics	1.0%
Survey was educatonal/informative	0.8%
Transparency on operations/revenue/spending/management salaries/investments	0.6%
Consumption/conservation efforts information/incentives	0.5%
Information on transformers/capacity	0.5%
Plans to reduce/lower consumer cost/rates/fees	0.5%
Appreciative of being heard/wanting customer input	0.4%
Alternative/green energy plans/info - solar, wind effectiveness/costs	0.4%
Replacing poles vs putting lines underground	0.4%
Impact of EV on the grid/explanation of increased demands	0.2%
Better outage communication/information	0.2%
Addressing seasonal rates/costs/concerns	0.1%
Government interference/involvement	0.1%
Environmental consideration	0.1%
Other	0.9%
Don’t know	89.7%
None	1.2%

Note: Only responses >0.1% shown

Seasonal Customers

Online Workbook Results

Online Workbook

Survey Design & Methodology

Seasonal

INNOVATIVE was engaged by Algoma Power Inc. to gather input on their proposed draft 2025-2029 business plan. Throughout this report, actual pages of the workbook that customers completed are included in the order that they were seen and are indicated by a watermark that says, "workbook page".

Field Dates & Workbook Delivery

The **Seasonal Online Workbook** was sent to all Algoma Power seasonal customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **December 7th, 2023 and January 1st, 2024**.

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

In total, the seasonal workbook was sent to **1,649** customers via e-blast from INNOVATIVE.
Two additional reminder emails were sent to those who had not yet completed the workbook in order to encourage participation and maximize response.

Seasonal

A total of **363** (unweighted) Algoma Power seasonal customers completed the online workbook via a unique URL.

Sample Weighting

The seasonal online workbook sample has been weighted proportionately by consumption quartiles and region in order to be representative of the broader Algoma Power service territory.

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

	Consumption Quartiles				Total
	First	Second	Third	Fourth	
North/West	38 (49)	41 (50)	52 (50)	67 (46)	198 (195)
East	16 (33)	33 (34)	42 (34)	56 (39)	147 (139)
Central	5 (6)	3 (3)	7 (4)	3 (3)	18 (16)
Total	59 (88)	77 (88)	101 (87)	126 (87)	363 (350)

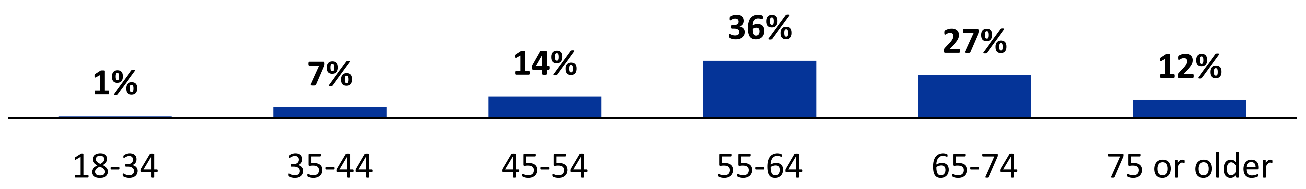
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Workbook

Demographic breakdown

Seasonal

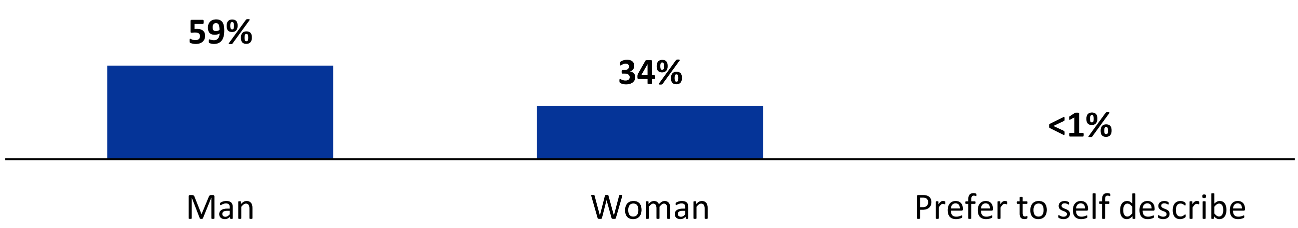
Q Age



“Prefer not to say”(3%) not shown.

n=350

Q Gender



“Prefer not to say”(7%) not shown.

n=350

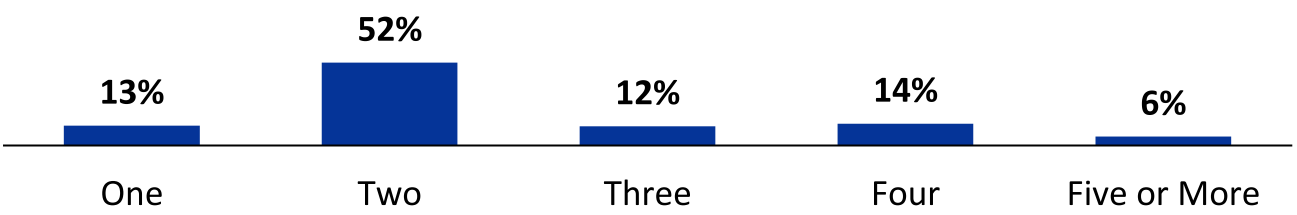
INNOVATIVE RESEARCH GROUP

Online Workbook

Demographic breakdown

Seasonal

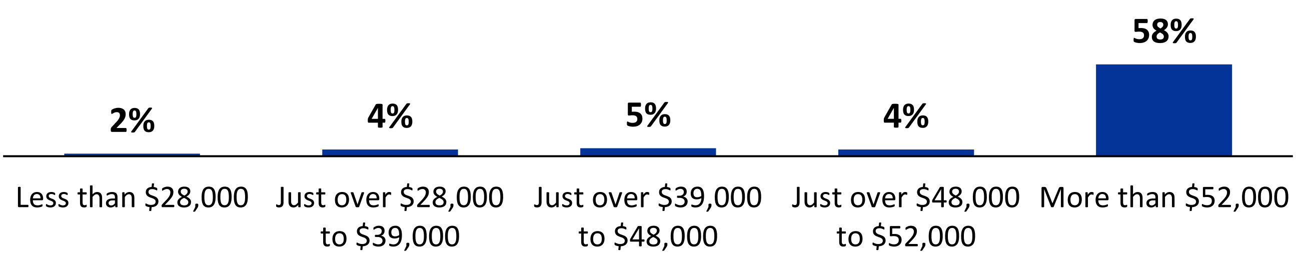
Q Household Size



“Prefer not to say” (3%) not shown.

n=350

Q After Tax Household Income



“Prefer not to say” (27%) not shown.

n=350

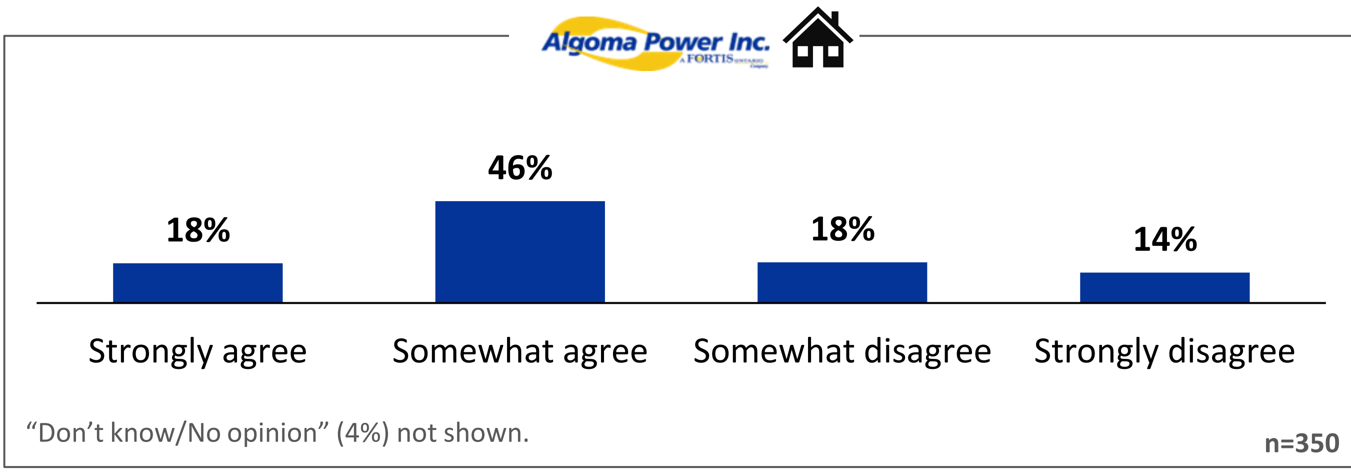
Online Workbook

Environmental Controls

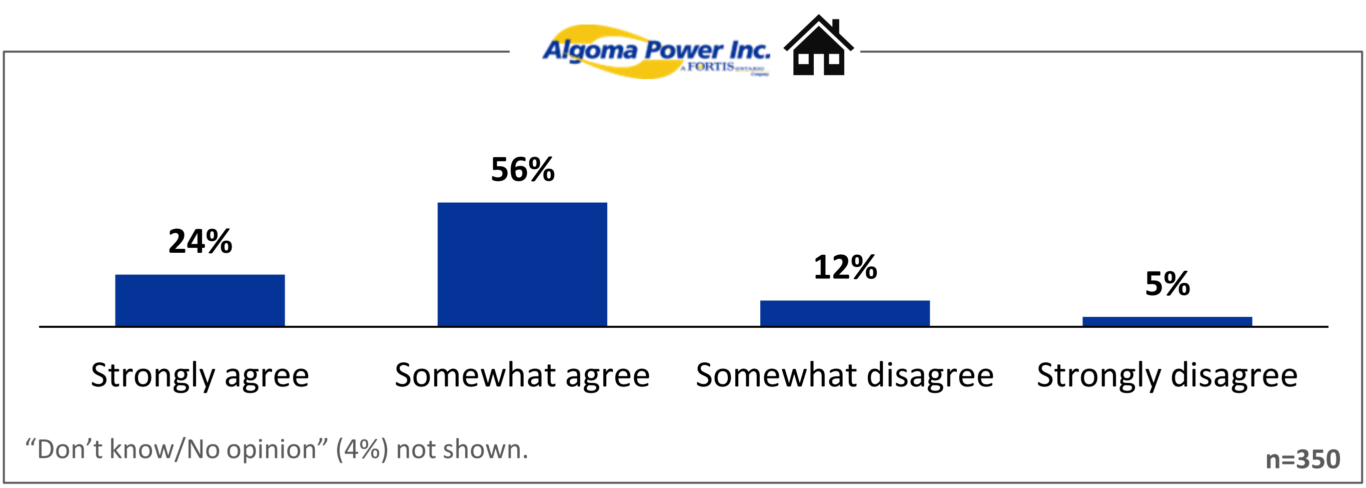
Seasonal

Now we would like to shift the focus and ask you some general questions about the electricity system in Ontario. 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.



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



Online Workbook

Seasonal

Planning for the Future: 2025-2029 Rate Application

About this Customer Engagement

Welcome to Algoma Power's customer engagement survey!

Over the course of the past year, Algoma Power has been developing its 2025-2029 business plan.

- **Today, Algoma Power is looking for your input on its draft plan** to ensure it is making spending decisions that matter to you, the customer.
- **In early 2024, Algoma Power plans to justify and present** its business plans to the public regulator, the Ontario Energy Board (OEB).
- **Beginning in 2025, based on the OEB's approval, Algoma Power will be updating the rate that you pay** for the delivery of electricity to your home or business.

This survey will take approximately 20 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved and you can return to the customer engagement at any time.

Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback and protect your confidentiality.

Those who complete the questions that follow will be invited to enter a draw to win one (1) of two (2) $500 VISA gift cards.

We thank you for your valuable time.

While the survey can be completed on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop computer, or laptop instead so that it is easier for you to read.

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Seasonal

About this Customer Engagement

What do we want to talk about?

Today's engagement will focus on two key areas while also allowing you to "colour outside the lines" and tell us what you think more broadly.

1. First, this engagement will seek to understand **what you feel Algoma Power should be prioritizing** over the next five years.

2. Next, you will be asked some questions about **specific investment decisions Algoma Power needs to make** related to overhead poles, wire, and other critical infrastructure.

But first, we need to ensure that we are all on the same page regarding Algoma Power's role in the broader electricity system, how much of your bill goes to Algoma Power, and where that money goes.

Online Workbook

Seasonal

Planning for the Future: 2025-2029 Rate Application

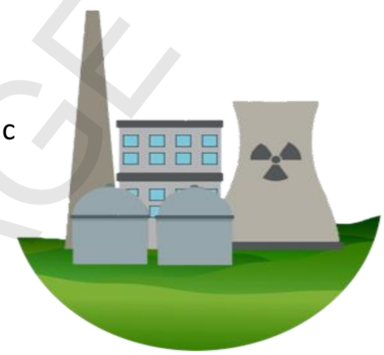
Electricity 101

Algoma Power's role in Ontario's electricity system

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

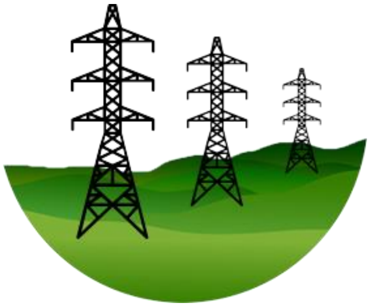


Ontario gets its electricity from a mix of energy sources. More than half comes from nuclear power. The remainder comes from a mix of hydroelectric and natural gas, and to a lesser extent, wind and solar.

Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from multiple generators who have contracts with the grid operator to provide power from a variety of sources.

Transmission

How electricity travels across Ontario



Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which are owned and operated by Hydro One.

Local Distribution

How electricity is delivered to the end-consumer

Algoma Power is responsible for the last step of the journey: distributing electricity to customers through its distribution system.

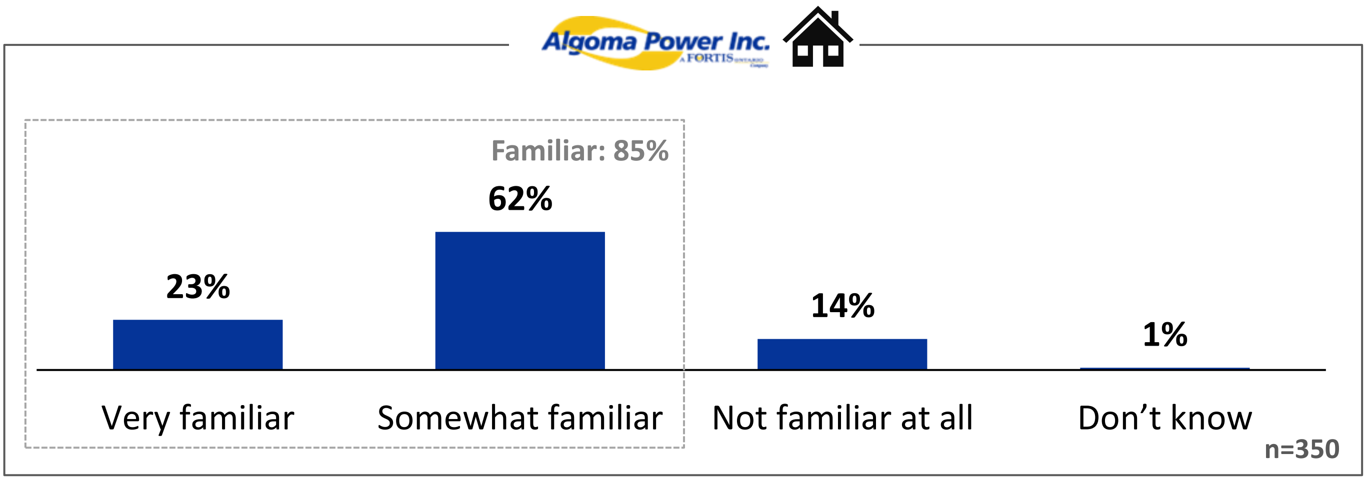
- Algoma Power manages all aspects of the electricity distribution business throughout the Algoma District of northern Ontario.
- In your community, amongst other functions, Algoma Power is responsible for:
  - Building and maintaining the local electricity distribution system
  - Responding to outage calls 24/7
  - Reading meters
  - Producing bills and accepting bill payments

Online Workbook

Familiarity with Algoma Power

Seasonal

Q Before this survey, how familiar would you say you were with Algoma Power and the role it plays in Ontario's electricity system?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Very familiar	22%	24%	18%	22%	23%	27%
Somewhat familiar	63%	61%	69%	59%	61%	60%
Not familiar at all	14%	14%	11%	16%	16%	13%
Don't know	1%	1%	1%	3%	--	--
Familiar (Very + Somewhat)	**85%**	**85%**	**87%**	**81%**	**84%**	**87%**

Online Workbook

Seasonal

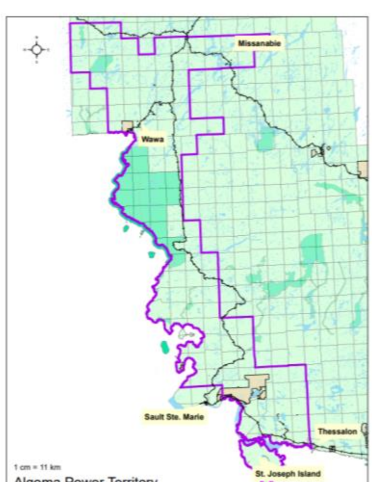
Planning for the Future: 2025-2029 Rate Application

Electricity 101

Who is Algoma Power?

Algoma Power services in the remote areas of Northern Ontario, extending 93 km east and approximately 340 km north of the City of Sault Ste. Marie, for a total of 14,200 km^2 of service territory, the second largest in Ontario.

- **Algoma Power does not generate or transmit electricity** — it owns and operates the local electricity system.
- **Algoma Power services about 12,000 customers,** over 14,200 km^2, making it the lowest-density distributor in Ontario. As a result of the low number of customers in such a large area, the cost to provide service to each customer on average is higher, as Algoma Power must install more equipment (ex: longer lines) to provide service to each customer.
- **Historically, much of Algoma Power's distribution system was built to service the resource sector and the communities that developed around those enterprises**. As a number of those industries declined or relocated, the result is a sparsely populated service territory with predominantly Seasonal and seasonal customers.
- **As with all other local distribution companies in Ontario, Algoma Power is funded by the distribution rates that you pay on your electricity bill**. Unlike most other utilities, a portion of this funding is recovered through other provincial funds intended to manage the affordability of distribution rates for rural and remote customers.
- As a local distribution company (LDC) and regulated entity, **Algoma Power can only charge the rates the regulator approves to charge for its services.**
- **The OEB runs an open and transparent review process** where experts from the regulator and intervenor groups review and challenge Algoma Power's analyses and assessments.



Algoma Power Territory

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Seasonal

Electricity 101

How much of my electricity bill goes to Algoma Power?

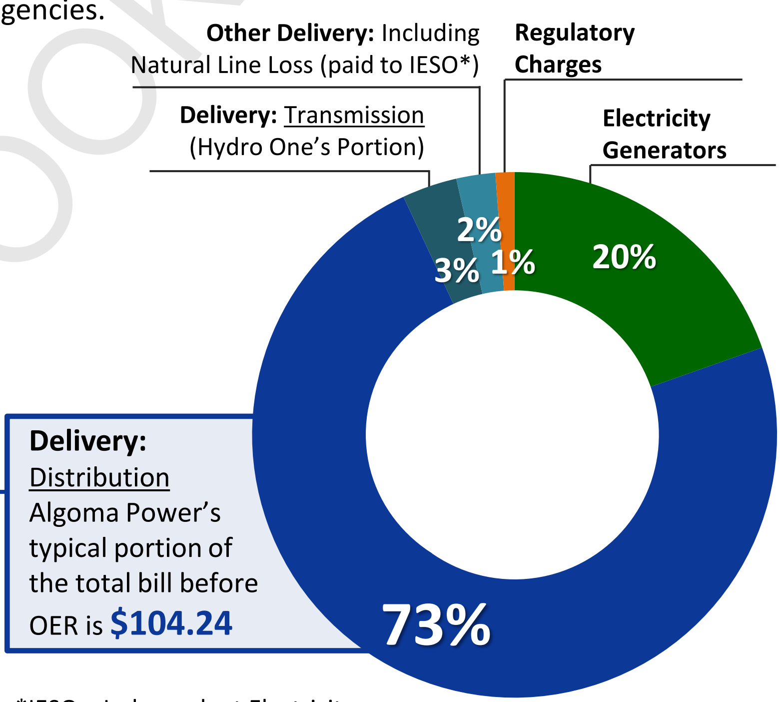
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While Algoma Power is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge. The delivery charge also includes Hydro One transmission costs and system losses.
- **Distribution makes up about 73% of the typical seasonal customer's bill, excluding the Ontario Electricity Rebate (OER) and Harmonized Sales Tax (HST).**
- The distribution portion of your bill, which goes towards operating and maintaining Algoma Power's distribution system, is largely fixed. Meaning, it does not change depending on how much electricity you use.
- The rest of your bill payment is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

Sample Algoma Power Monthly Bill
(based on consumption of 250 kWh as of Nov. 1, 2023)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 18.2 c/kWh	**8.65**
Mid-Peak (mid price) @ 12.2 c/kWh	**5.49**
Off-Peak (lowest price) @ 8.7 c/kWh	**13.70**
Delivery	**112.46**
Regulatory Charges	**1.66**
Total Electricity Charges	**$141.96**
HST	**18.45**
Ontario Electricity Rebate	**(-$27.40)**
Total Amount	**$133.01**



*IESO = Independent Electricity System Operator

Chart is based on total bill of $141.96 excluding the Ontario Electricity Rebate and HST. Chart may not total 100% due to rounding.

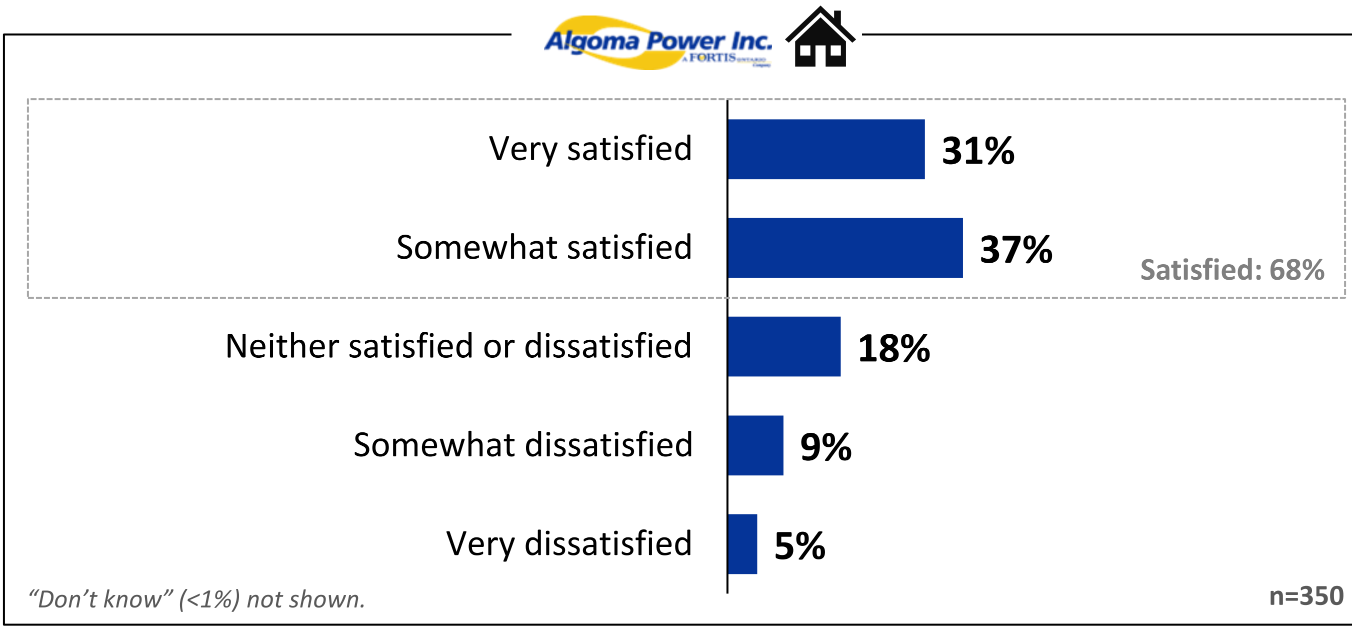
The sample bill above uses an average consumption level of 250kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

Online Workbook

Familiarity with Algoma Power

Seasonal

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



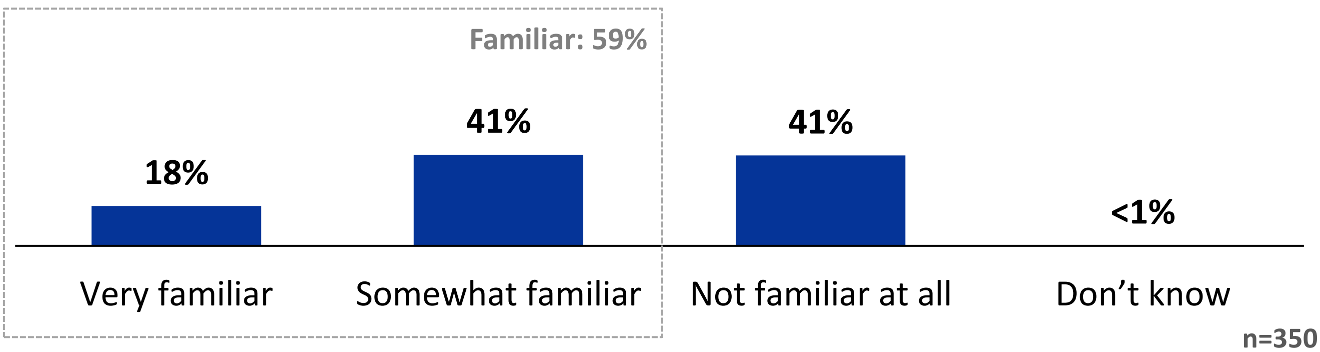
	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Very satisfied	34%	28%	33%	30%	35%	27%
Somewhat satisfied	37%	37%	35%	39%	32%	42%
Neither satisfied nor dissatisfied	19%	17%	20%	15%	21%	16%
Somewhat dissatisfied	6%	13%	10%	9%	5%	11%
Very dissatisfied	4%	6%	1%	7%	6%	4%
Don't know	1%	--	--	--	1%	1%
Satisfied (Very + Somewhat)	**71%**	**65%**	**69%**	**69%**	**67%**	**68%**
Dissatisfied (Very + Somewhat)	**9%**	**19%**	**11%**	**16%**	**11%**	**15%**

Online Workbook

Seasonal

Familiarity with the Percentage of Bill Remitted to Algoma Power

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



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Very familiar	17%	19%	10%	15%	23%	24%
Somewhat familiar	43%	39%	42%	42%	33%	47%
Not familiar at all	40%	42%	48%	43%	44%	28%
Don't know	--	<1%	--	--	--	1%
Familiar (Very + Somewhat)	**60%**	**57%**	**52%**	**57%**	**56%**	**71%**

Online Workbook

Seasonal

How Algoma Power can Improve Services to Customers

Q Is there anything in particular you would like Algoma Power to do to improve its services to you?

Additional Comments	%
Lower cost/rates/delivery charge	16.5%
Adjust rates for seasonal properties/properties that consume no power some of the time	16.2%
Improve pole/line maintenance/better tree clearing/bury lines	5.8%
Improve infrastructure/grid/reliability/power quality/number of outages	3.1%
Improve communication for planned/unplanned outages	2.3%
Satisfied with service/no improvements necessary	1.4%
Improve billing issues - clarity/explain costs/accuracy/payment methods/consistency	0.5%
Offer more alternative/green energy sources/less fossil fuels	0.4%
Improve customer service/administrative processes	0.2%
Improve online resources/website/portal	0.2%
Improve communication/transparency with customers	0.2%
Other	0.3%
Don't know	0.9%
None	52.1%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Online Workbook

Setting Priorities within Algoma Power's Plans

Seasonal

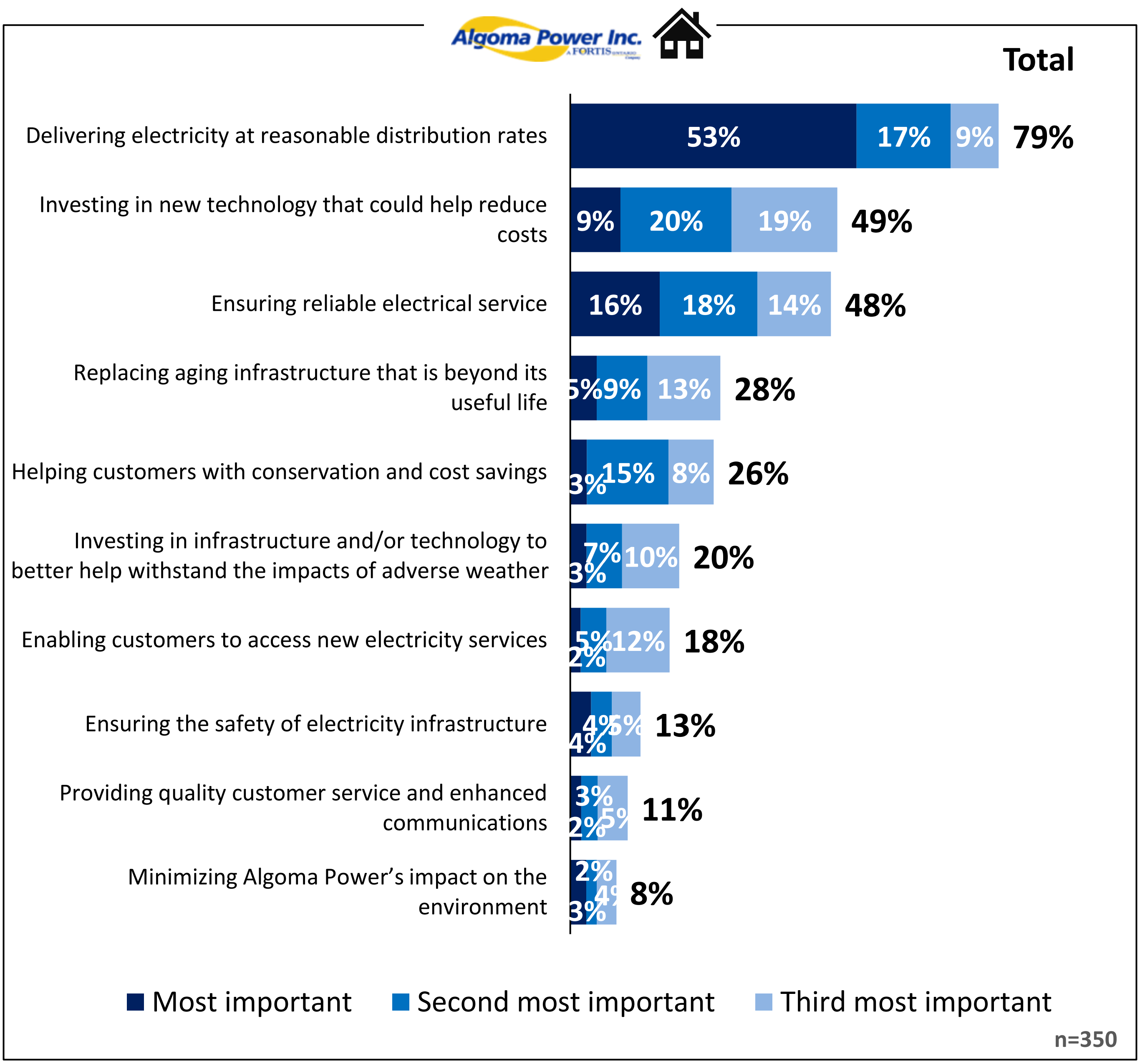
Q

As with all businesses, Algoma Power must make decisions on which areas they are going to prioritize within their business plans.

Based on ongoing conversations with customers, a number of company goals have been identified as priorities for Algoma Power.

Looking at the list below, please rank your top 3 priorities—where "1" would be the most important, "2" the second most important, and "3" the third most important.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, and ending with the third most important.



Online Workbook

Seasonal

Setting Priorities within Algoma Power's Plans

% Total Important (top three)	Region	
	North/West	Central/East
Delivering electricity at reasonable distribution rates	78%	80%
Investing in new technology that could help reduce costs	48%	50%
Ensuring reliable electrical service	49%	47%
Replacing aging infrastructure	31%	23%
Helping customers with conservation and cost savings	29%	24%
Investing in infrastructure/tech to withstand adverse weather	17%	24%
Enabling customers to access new electricity services	16%	21%
Ensuring the safety of electricity infrastructure	14%	12%
Providing quality customer service	9%	12%
Minimizing Algoma Power's impact on the environment	9%	7%

% Total Important (top three)	Consumption Quartiles			
	First	Second	Third	Fourth
Delivering electricity at reasonable distribution rates	83%	80%	80%	72%
Investing in new technology that could help reduce costs	56%	48%	49%	44%
Ensuring reliable electrical service	50%	44%	47%	51%
Replacing aging infrastructure	32%	25%	21%	32%
Helping customers with conservation and cost savings	17%	26%	34%	28%
Investing in infrastructure/tech to withstand adverse weather	19%	20%	15%	26%
Enabling customers to access new electricity services	18%	19%	14%	22%
Ensuring the safety of electricity infrastructure	16%	13%	11%	11%
Providing quality customer service	6%	9%	20%	7%
Minimizing Algoma Power's impact on the environment	3%	15%	9%	8%

Online Workbook

Other Important Priorities

Seasonal

Q Can you think of any other important priorities that Algoma Power should be focusing on?

Additional Comments	%
Affordability/reducing costs	6.1%
Charge seasonal customers equally/stop overcharging seasonal customers	5.2%
The priorities mentioned earlier are all important/all the above	3.2%
Preparing the grid/infrastructure for the future	1.8%
Consider environmental impact/offer alternative energy options	1.6%
Better line maintenance/bury lines	1.5%
Improving reliability/reducing outages	0.9%
Being transparent with customers	0.8%
Focus on safety measures/safety of workers	0.4%
Educating customers on reducing power consumption	0.4%
Helping seniors/low income customers	0.2%
Other	2.2%
None	75.4%

Note: Only responses >0.1% shown

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Seasonal

Background Context

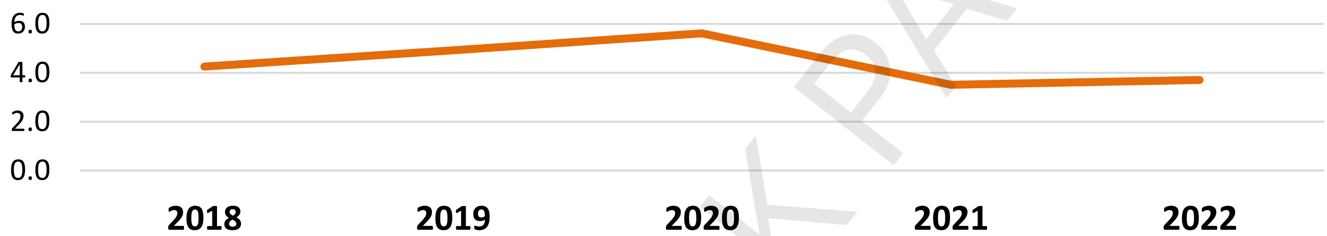
Focus on Reliability

Since reliable electricity service is so important to customers, before we move on, we want to ask you about which specific areas you feel that Algoma Power should focus on over the next five years.

Algoma Power tracks both the **average number of power outages** per customer and **how long those interruptions last**.

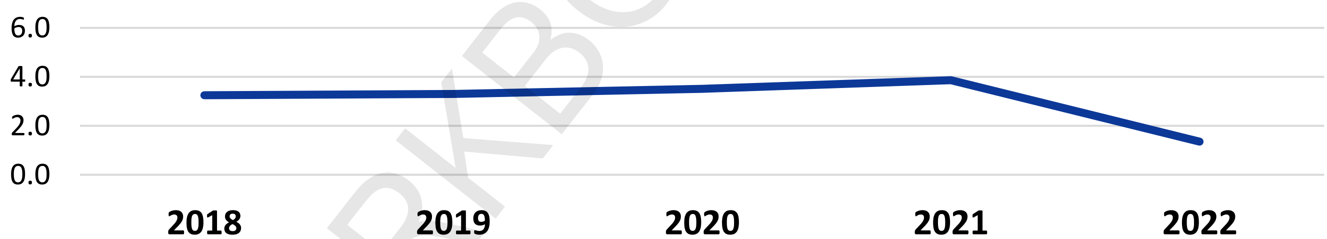
Between 2018 and 2022, the typical Algoma Power customer has experienced about **4 and a half outages per year**.

Average number of outages (outages per customer)



Over the same period, the **average duration of an outage has been about 3 hours**. Meaning, when the power does go out, Algoma Power is typically able to restore power in about three hours.

Average duration of an outage (per year)



It's important to keep in mind that these are system averages, and that your actual experience may be different.

- Generally speaking, the further away a customer is from the distribution substation, the more outages the customer will likely experience, as longer distribution lines have a higher probability of being damaged.
- Some customers connected to newer lines may not experience any outages, while others are experiencing more than the average number of outages each year.

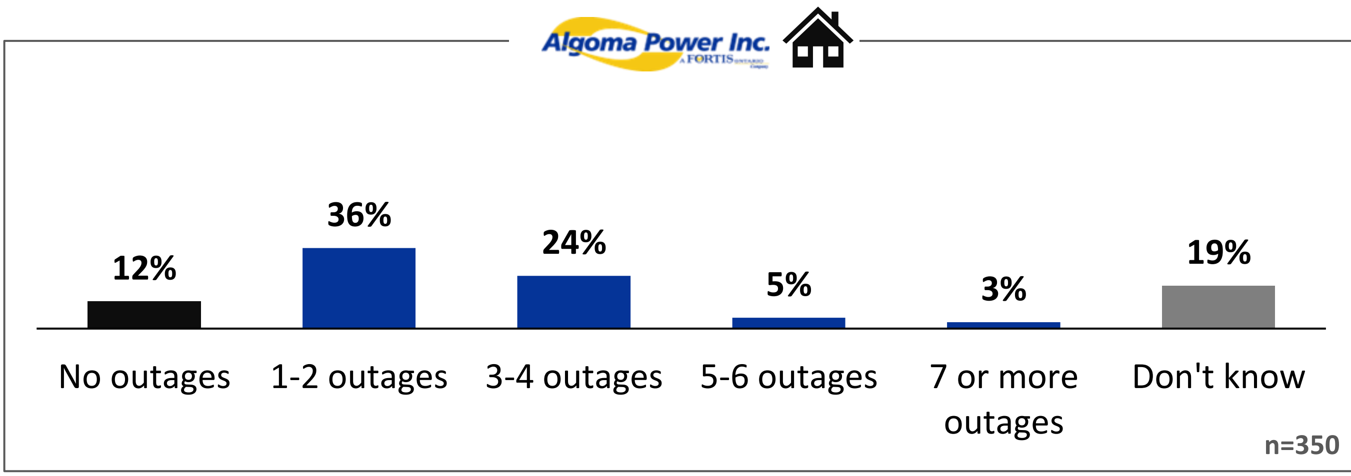
The tables and figures above include outages related to extreme weather events and transmission loss of supply events (which Algoma Power has relatively lower ability to control).

Online Workbook

Number of Outages Experienced

Seasonal

Q Have you experienced any power outages as an Algoma Power customer in the past 12 months which lasted longer than one minute?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
No outages	15%	8%	23%	8%	11%	7%
1-2 outages	34%	39%	37%	39%	38%	32%
3-4 outages	23%	25%	16%	26%	24%	29%
5-6 outages	4%	6%	--	4%	6%	10%
7 or more outages	--	7%	2%	1%	2%	6%

Online Workbook

Seasonal

Planning for the Future: 2025-2029 Rate Application

Background Context

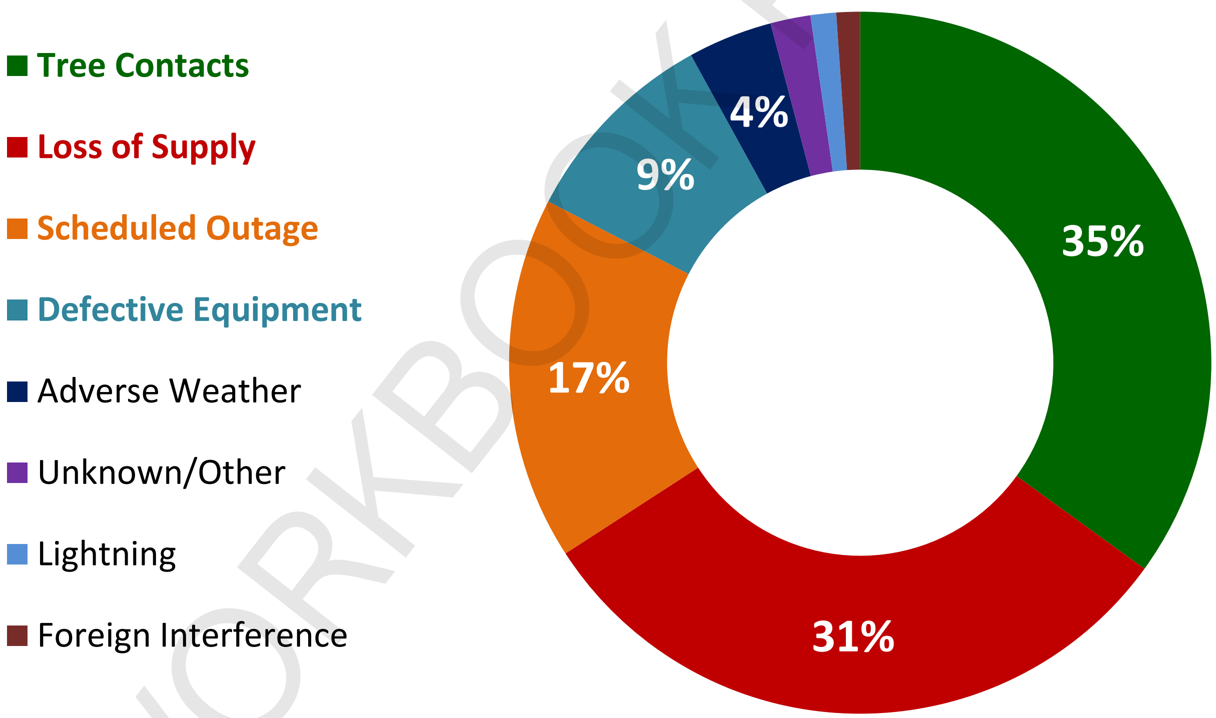
Focus on Reliability

Since 2018, 66% of all outages have been traced back to two causes – tree contacts (35%) and loss of supply from the transmission system (31%) operated by Hydro One.

While transmission system failures are largely out of the control of Algoma Power, there are investments that can be made to attempt to reduce the impacts of tree contacts, defective equipment, and even adverse weather.

Algoma Power has three service centres located in Desbarats, Wawa and Sault Ste. Marie that allow staff to respond to outages throughout the service territory.

Customer Outage Duration (Hours) by Cause 2018-2022



Online Workbook

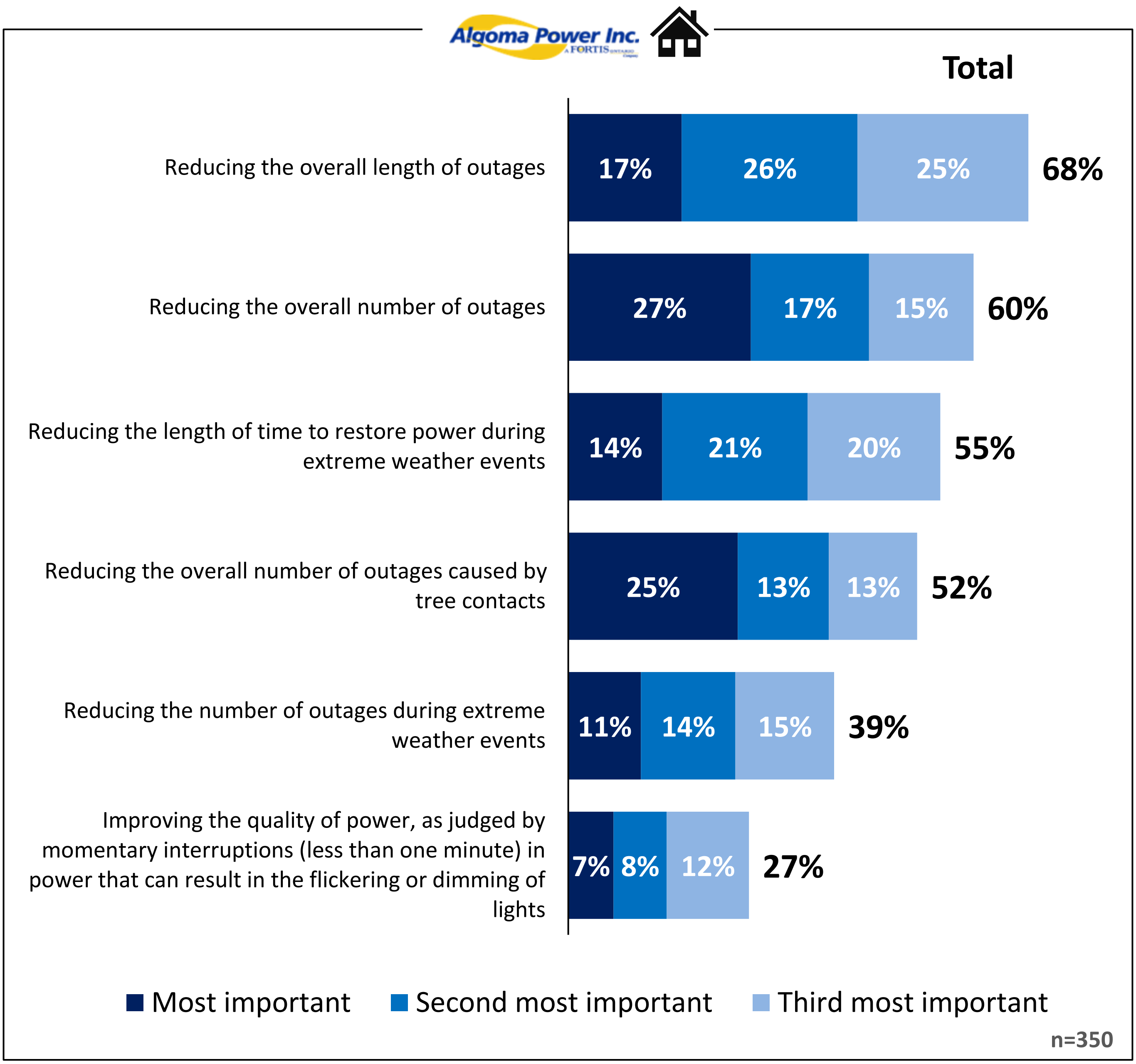
Reliability Priorities

Seasonal

Q

Since reliable electricity service is so important to customers, before we move on, we want to ask you about which specific areas you feel that Algoma Power should focus on over the next five years.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, and ending with the third most important.



Online Workbook

Reliability Priorities

Seasonal

% Total Important (top three)	Region	
	North/West	Central/East
Reducing the overall length of outages	69%	67%
Reducing the overall number of outages	59%	61%
Reducing the length of time to restore power during extreme weather events	52%	58%
Reducing the overall number of outages caused by tree contacts	51%	52%
Reducing the number of outages during extreme weather events	40%	38%
Improving the quality of power, as judged by momentary interruptions	29%	24%

% Total Important (top three)	Consumption Quartiles			
	First	Second	Third	Fourth
Reducing the overall length of outages	62%	71%	71%	67%
Reducing the overall number of outages	54%	59%	65%	61%
Reducing the length of time to restore power during extreme weather events	52%	48%	62%	58%
Reducing the overall number of outages caused by tree contacts	49%	52%	52%	53%
Reducing the number of outages during extreme weather events	55%	37%	27%	38%
Improving the quality of power, as judged by momentary interruptions	28%	33%	23%	23%

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Seasonal

Algoma Power Background

How does Algoma Power propose to spend your money?

As mentioned, a portion of all Algoma Power customer bills goes towards operating and maintaining the electricity system. In addition to customer rates, some provincial funding also helps fund the budget which Algoma Power uses to operate its system. Over the five-year period from 2020 to 2024, this has resulted in a 5-year budget of **$146.7 million**.

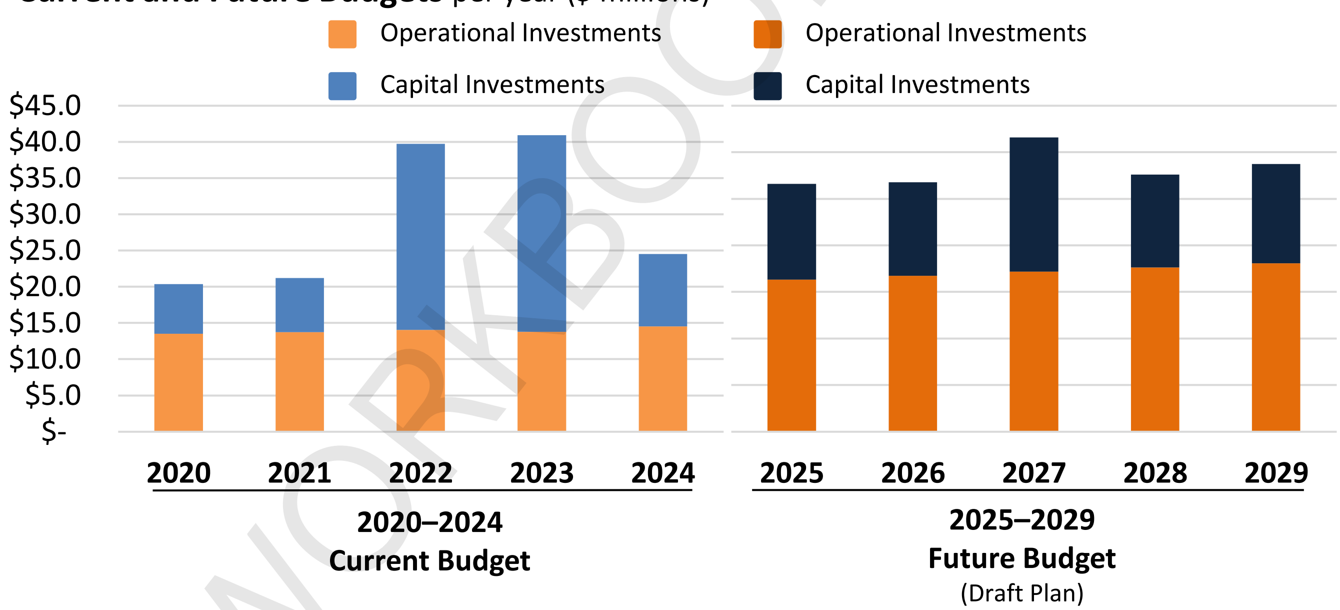
Between 2025 and 2029, Algoma Power is proposing to spend $141.3 million, a 3.7% decrease relative to the past five years.

To run the local grid and serve customers, Algoma Power manages two budgets:

1. A **capital investment** budget which pays for the cost of buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks, and computers.

2. An **operational investment** budget which pays for maintenance, testing, and operation of the equipment, vegetation management, as well as the staff needed to manage the grid and serve customers daily.

Current and Future Budgets per year ($ millions)



The current five-year budget of **$146.7 million** is based on the 2020–2024 plan approved by the OEB in a previous rate application. As mentioned earlier, this amount is funded by your 2020–2024 distribution rates.

The future five-year budget of **$141.3 million** is based on the 2025–2029 draft plan presented in this customer feedback survey. The final budget for this next rate period will be adjusted to reflect customer feedback collected through this engagement and will be subject to extensive OEB review before rates are set for 2025–2029.

Online Workbook

Seasonal

Planning for the Future: 2025-2029 Rate Application

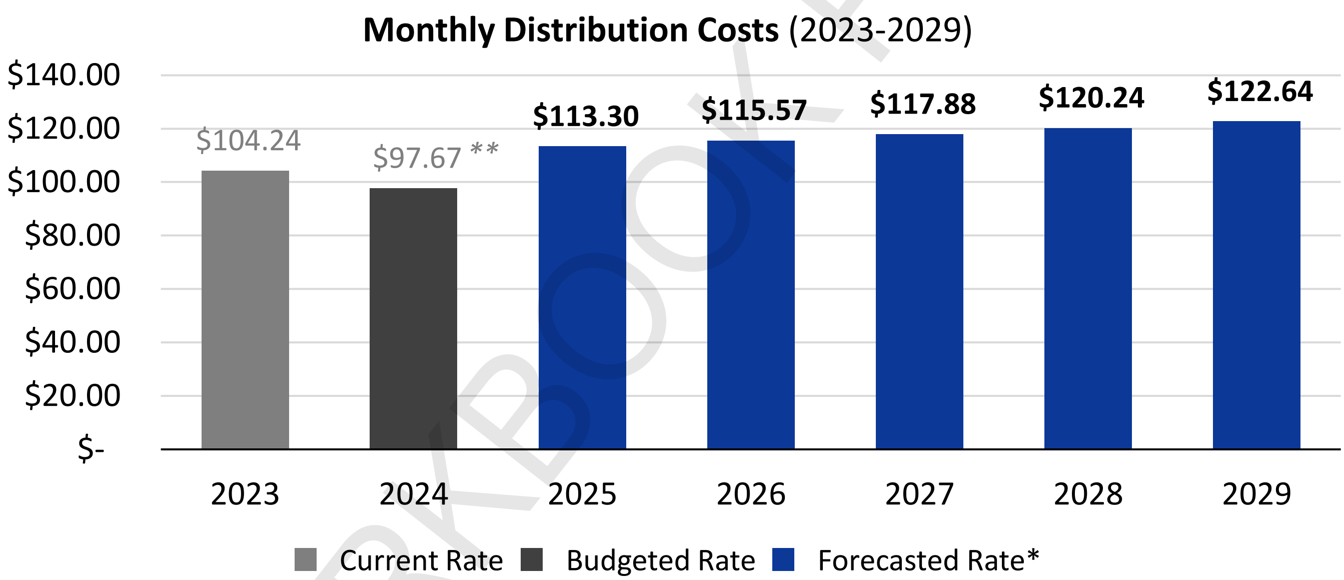
Algoma Power Background

How much will Algoma Power's draft plan cost me?

It is estimated that if Algoma Power continues with its draft plan, the distribution portion of the bill will be **$113.30 in 2025**, an increase of $15.63 per month compared to the budgeted **$97.67 in 2024**.

- For the period of 2025-2029, the annual bill increase is limited by the Ontario Energy Board (OEB) to an amount less than the rate of inflation with the exception of any one-time capital expenditures.
- As a result, over the 2025-2029 period, the distribution portion of the bill is forecasted to increase by an average of 2% per year.

Under this draft plan, by 2030, the typical seasonal customer will be paying an estimated $18.40 more on the distribution portion of their bill compared to today.



** These estimates are preliminary and are subject to your feedback as the business plan is finalized.*

*** Reduction in 2024 is due to expiry of a historical rate.*

Estimates are subject to change with factors including inflation, rate design updates, and pass through cost variations. A comprehensive budget for new 2030 projects/rates has not yet been developed.

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Seasonal

Algoma Power Background

What does Algoma Power want your feedback on?

Today, Algoma Power is seeking your input on its draft plan to ensure it is making the spending decisions that matter to you, the customer.

- The following sections of this workbook will explore 6 choices that Algoma Power needs to make to finalize its plans.
- Algoma Power will need to demonstrate to the OEB both what they heard from customers, as well as how they reflected your feedback in its plans.

How do I make choices?

Each choice has a summary of the options that Algoma Power is considering. In many cases, that includes options that would see Algoma Power ***spend less*** or ***more*** than what is currently being proposed.

- For each option you will be presented with to ***spend more*** or ***less***, Algoma Power has estimated what impact that would have on customer bills.
- Following each question, you will also have an opportunity to provide additional optional feedback if you choose to.

Now, let's get started with Algoma Power's first decision related to **pole replacement**.

Online Workbook

Seasonal

Planning for the Future: 2025-2029 Rate Application

Making Choices (1 of 6)

Pole and Line Replacement

Background: As previously mentioned, Algoma Power has one of the largest (by geography) service territories of any electricity utility in Ontario. As such, Algoma Power operates and maintains 2,108 km of distribution line that is supported by 28,931 poles.

Each year, Algoma Power identifies and prioritizes pole lines for rebuilding based on their condition, age, and the consequences of their potential failure.

A recent assessment showed that about 3% or 972 of Algoma Power's poles were deemed to be in poor or very poor condition. Meaning, while rare, these 972 poles are at increased likelihood of "failing", which would likely cause a power outage for customers supplied by the line.

Current approach: Historically, Algoma Power has proactively replaced 500 poles per year or about 2% of all the poles in the system.

This approach has resulted, in part, in the current levels of reliability that you experience today. If Algoma Power gets too far behind on proactively replacing older poles, it can result in more outages and more costly reactive repairs. One pole can serve as many as 2,000 customers or as few as one.

2025-2029 proposed approach: Each year, as Algoma Power assesses a portion of its poles, some poles that were previously deemed to be in good condition are re-classified as poor or very poor. As such, over the next five years, Algoma Power is proposing to stay on the normal course and proactively replace 500 poles per year. Replacements are always prioritized based on condition and operational effectiveness.

Algoma Power also has an option to do more or less. When less is done, it increases the chances of more outages and more costly reactive repairs, but also pushes some of the associated costs further down the road. When more is done, it can result in some minor improvements to reliability, and get ahead of the curve at an additional cost.

Online Workbook

Choice 1: Pole and Line Replacement

Seasonal

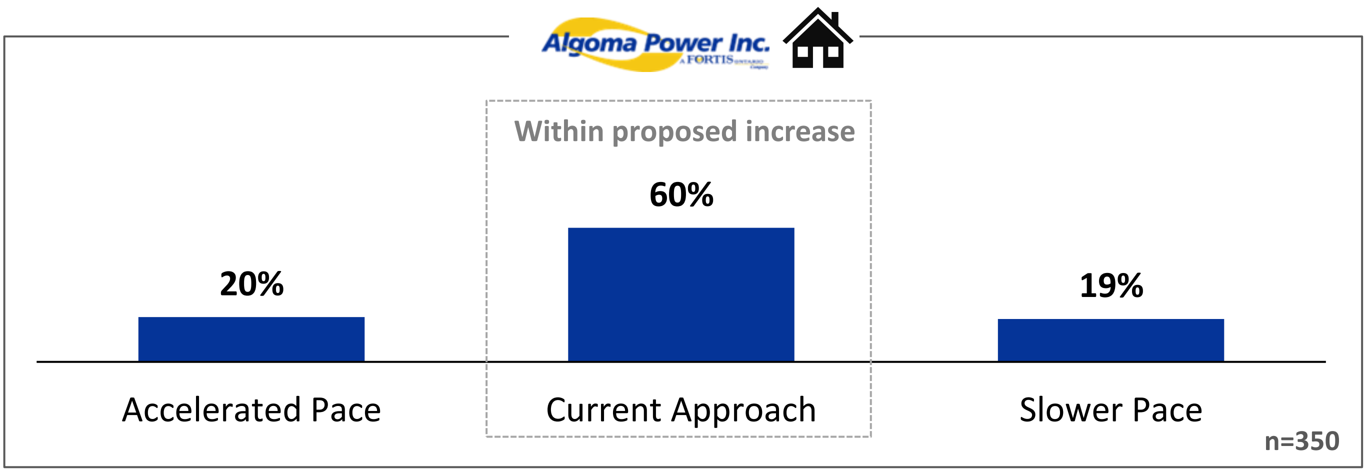
Which of the following options do you prefer?		
Option	Poles Replaced	Expected Outcome
Accelerated Pace ***$0.83*** *more on monthly bill by 2030*	Proactively replace 550 poles per year for the next five years.	• Increase the current pole replacement pace by 50 per year. • Potentially see reliability improvements due to decreased likelihood of pole failure resulting in outages. • "Get ahead" of pole replacement in subsequent years.
Current Approach *Within proposed rate increase*	Proactively replace 500 poles per year for the next five years.	• As this is the current approach, Algoma Power customers could expect to see similar reliability as it relates to poles (understanding that this is just one part of the system).
Slower Pace ***$0.83*** *less on monthly bill by 2030*	Proactively replace 450 poles per year for the next five years.	• Reduce the current pole replacement pace by 50 per year. • Potentially see an increased risk of failures resulting in outages. • Would reduce costs now but could result in increased costs in future years as more poles need to be replaced.
Additional Feedback (Optional)		

Online Workbook

Choice 1: Pole and Line Replacement

Seasonal

Q Which of the following options do you prefer?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Accelerated Pace	18%	23%	19%	18%	23%	20%
Current Approach	62%	59%	56%	61%	59%	66%
Slower Pace	20%	19%	24%	21%	18%	14%

Online Workbook

Choice 1: Pole and Line Replacement

Seasonal

Q Which of the following options do you prefer?

Additional Comments	%
Lower rates/no increase/cost too high already/keep it affordable	1.8%
Need more information/have questions	1.2%
Prioritize replacement/depending on analysis of pole conditions	1.1%
Only replace when needed	0.9%
Replace as quick as possible	0.8%
Reliability is acceptable	0.7%
Instead of replacing poles, bury lines underground	0.6%
Find efficiencies from within/upgrades should have been planned into budget	0.5%
Poles do not seem to be the issue	0.5%
More sustainable material for poles/not using wood/alternatives	0.5%
Replace poles now to avoid future cost increases	0.4%
None	91.0%

Note: Only responses >0.1% shown

Online Workbook

Seasonal

Planning for the Future: 2025-2029 Rate Application

Making Choices (2 of 6)

Substation Rebuild

Background: Algoma Power owns and operates 9 substations. These substations, as pictured below, are used to “step down” the voltage supplied from Hydro One prior to distribution to customers. The equipment contained within these substations is critical and has a typical useful life of 50 years. The substation pictured below is in the town of Wawa and was built more than 50 years ago. Algoma Power has historically replaced substations as their age and condition requires it, for example a project is currently underway for a substation replacement in Bruce Mines this year.

The town of Wawa, with a population of 2,705 (2021 Census) is served by two substations. If one substation were to fail, the other would be able to back it up for a period, but not as a long-term solution.

As more customers start getting electric vehicles, solar panels, or just generally continue to use more electricity as an alternative to gas and other fuel sources, Algoma Power must right-size the substation transformer capacity to accommodate these increases in electrical demand. If electricity demand exceeds the transformer capacity, this could result in higher costs in the future.

Current approach: The lead time to replace the critical equipment within a substation can be anywhere from 1 to 3 years. In this case, if one of the substations servicing the town of Wawa were to fail, the entire community could be left without backup for years.

As such, when substation equipment is assessed in poor condition, Algoma Power typically starts planning to rebuild that substation, knowing that it can take years to plan, design and construct the rebuild.

2025-2029 proposed approach: In this upcoming plan, the question is not whether this substation in the town of Wawa needs to be rebuilt, but rather if Algoma Power uses this opportunity to update the equipment to prepare for growth in the community and the associated increase in electricity demand.

The “like-for-like” replacement option would see Algoma Power installing similar equipment to what has been in place for more than 50 years. This has served customers well for many years; however, in this case, Algoma Power is proposing to upgrade the equipment to be better prepared for community growth.

Online Workbook

Choice 2: Substation Rebuild

Seasonal

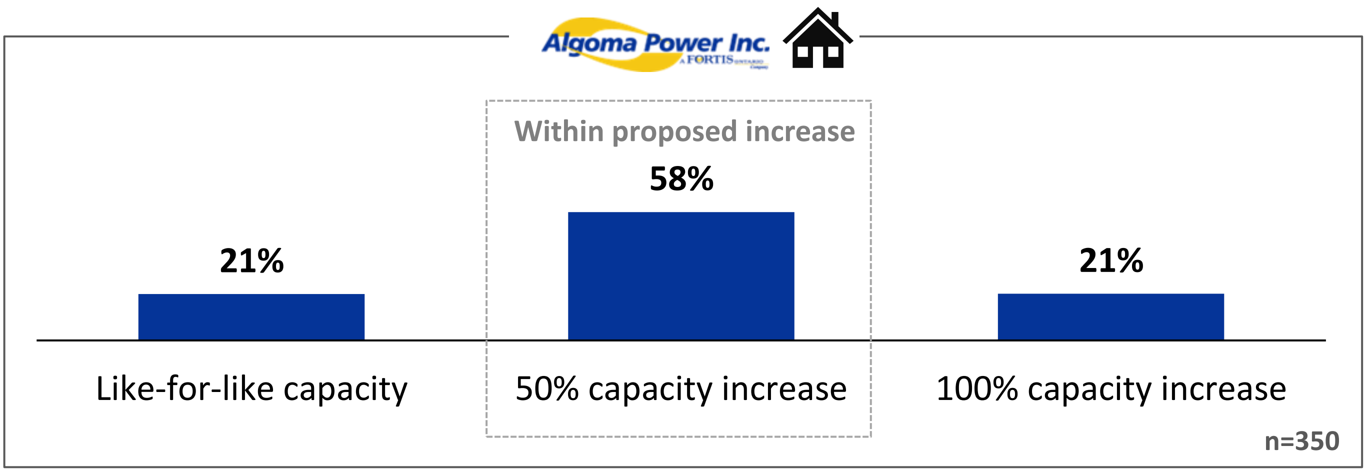
Which of the following options do you prefer?		
Option	**Transformer Size**	**Expected Outcome**
Like-for-like capacity ***$0.09*** *<u>less</u> on monthly bill by 2030*	Procure and install a power transformer that is similar in capacity to the existing transformer.	Increased risk of premature transformer replacement as electricity uses increases as a result of overall home and business electrification.
50% capacity increase *Within proposed rate increase*	Procure and install a power transformer with a capacity that is 50% larger than the existing transformer.	Transformer capacity is sized in accordance with projected load increases associated with overall home and business electrification.
100% capacity increase ***$0.09*** *<u>more</u> on monthly bill by 2030*	Procure and install a power transformer with a capacity that is 100% larger than the existing transformer.	Larger transformer capacity would support increased electricity usage beyond the projected load increases.
Additional Feedback (Optional)		

Online Workbook

Choice 2: Substation Rebuild

Seasonal

Q Which of the following options do you prefer?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Like-for-like capacity	20%	22%	15%	29%	17%	24%
50% capacity increase	58%	58%	67%	48%	61%	55%
100% capacity increase	22%	20%	18%	23%	22%	21%

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Online Workbook

Choice 2: Substation Rebuild

Seasonal

Q Which of the following options do you prefer?

Additional Comments	%
Not all customers should pay for specific upgrades/area based	1.3%
Skeptical of significant demand growth	1.3%
Depends on the growth in the community	0.9%
Lack of planning/foresight/costs should not be passed onto customers	0.8%
Transition to EV/alternatives not practical in the area	0.8%
Replace now to prepare for population growth/demands	0.8%
Customers not qualified to decide/professional assessments required	0.7%
Costs need to be lower	0.7%
Need more information/have questions/not enough details	0.6%
Be proactive with the replacements	0.6%
The capacity increase is necessary	0.5%
Support gradual approach/replace oldest first	0.2%
No answer	90.8%

Note: Only responses >0.1% shown

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Seasonal

Planning for the Future: 2025-2029 Rate Application

Making Choices (3 of 6)

Voltage Conversion

Background: Much of Algoma Power's service territory is serviced by low-voltage distribution lines. These lines have much less capacity than modern lines. Meaning, that as demand for electricity increases, these lines struggle to distribute the constant flow of electricity that customers expect.

Current approach: These low-voltage distribution lines have historically served customers well, and in most cases will continue to do so. As such, upgrading these lines has not been a priority for Algoma Power in the past. However, in the future, increased demand for electricity means some of these lines are more likely to either fail or result in electricity flickering. When electricity flickers, it can result in homes and businesses having to re-set appliances or equipment, the clock on your stove, or other power quality issues. For local businesses, this can be particularly disruptive as machines and processes may be disrupted. This is more likely to occur in parts of the service territory where electricity demand increases more rapidly.

2025-2029 proposed approach: Starting in 2025, Algoma Power is proposing line upgrades to start mitigating some of the risks associated with these lower voltage lines.

Algoma Power has identified portions of the distribution system in the Goulais River and Batchawana Bay areas that serve 3,980 customers and are at risk of decreasing voltage reliability and power quality as the system load increases. To mitigate this risk, Algoma Power has proposed to convert the system voltage to a higher level.

Algoma Power is contemplating three pacing options to complete the voltage conversion in the Goulais River and Batchawana Bay areas - a minimum-level, mid-level and full-level voltage conversion plan. What isn't completed in this upcoming 5-year period will need to be completed in the next cycle. Doing more in the next 5-years will reduce the risk of equipment failure and power quality issues but increase the price you pay over this period. While the question requests your feedback on a project in a specific area, Algoma Power will take your feedback into account when looking at voltage conversion in other areas of the system.

Online Workbook

Choice 3: Voltage Conversion

Seasonal

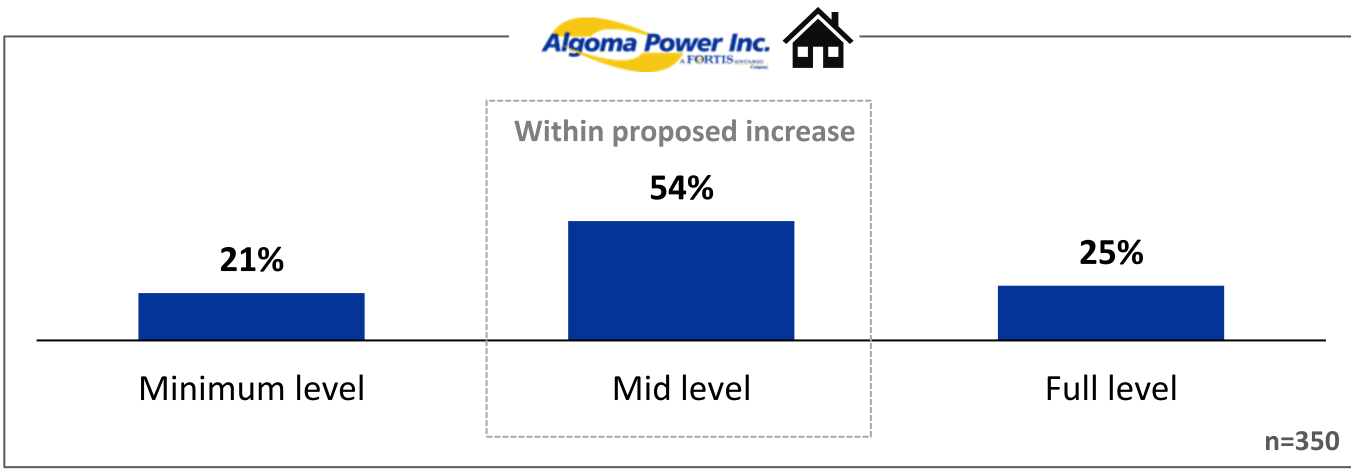
Which of the following options do you prefer?		
Option	% Upgraded	Expected Outcome
Minimum Level ***$0.07*** *less on monthly bill by 2030*	Upgrade and convert approximately 25% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 995 customers. • Lower cost now, but more will need to be deferred to the next cycle.
Mid Level *Within proposed rate increase*	Upgrade and convert approximately 50% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 1,990 customers. • Lower cost now, but some will need to be deferred to the next cycle.
Full Level ***$0.70*** *more on monthly bill by 2030*	Upgrade and convert approximately 100% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 3,980 customers. • Higher cost now, but none will need to be deferred to the next cycle.
Additional Feedback (Optional)		

Online Workbook

Choice 3: Voltage Conversion

Seasonal

Q Which of the following options do you prefer?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Minimum level	20%	23%	18%	22%	24%	21%
Mid level	55%	53%	57%	56%	54%	48%
Full level	25%	24%	25%	21%	22%	31%

Online Workbook

Choice 3: Voltage Conversion

Seasonal

Q Which of the following options do you prefer?

Additional Comments	%
Not all customers should pay for specific upgrades/area based	0.8%
Replace as quick as possible	0.6%
Be proactive with the replacements	0.6%
Skeptical of EV increases in the area	0.4%
Lower rates/no increase/cost too high already/keep it affordable	0.4%
Underground lines	0.3%
Don't know enough to make the decision/leave it to the experts	0.3%
Government should cover costs	0.2%
Doesn't apply to me	0.2%
Willing to pay more for reliable service	0.2%
None	96.0%

Note: Only responses >0.1% shown

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Seasonal

Making Choices (4 of 6)

Preparing for increased electricity demand

Background: Transformers are a critical piece of equipment that reduces the voltage of electricity before it enters your home or business. These transformers 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. That means a business using lots of electricity will generally have a larger transformer serving it than a typical 2- or 3-bedroom home.

But today, the "smaller" transformers that have historically served Seasonal homes are increasingly struggling to keep up with increased demand. That means, today, when a transformer fails, it's replaced with a "larger" one to accommodate the increased demand for electricity.

Current approach: Currently, as is the case with most electricity utilities in Ontario, Algoma Power operates its transformers until they fail. When a transformer does fail, it typically takes between 2 and 4 hours to replace it and get the power back on for the customers that it serves.

However, as more customers start getting electric vehicles, solar panels, or just generally continue to use more electricity as an alternative to gas and other fuel sources, Algoma Power is projecting that more and more transformers will need to be upgraded to accommodate these changes. If demand increases quicker than Algoma Power can upgrade transformers, this could lead to transformers failing more frequently.

2025-2029 proposed approach : Over the next five years, Algoma Power is proposing a similar approach to what has been done in the past. That is, run the transformers until they fail and replace them with "larger" transformers to accommodate increased electricity usage.

However, depending on what customers value, Algoma Power is considering a new program that would identify areas in the community with the greatest increase in demand, and proactively swapping out the smaller transformers for larger ones to avoid potential failures. This new program wouldn't have a significant impact on current reliability but would help ensure that when the time comes, customers will have access to the electricity they want to meet their growing and changing needs.

If demand for electricity from customers increases more rapidly than expected, Algoma Power may have to cancel or delay other planned projects to accommodate these newer transformers that aren't budgeted for.

Online Workbook

Seasonal

Choice 4: Preparing for increased electricity demand

Which of the following options do you prefer?

Option	Transformers Replaced	Expected Outcome
Status Quo *Within proposed rate increase*	Based on historical data, reactively replace approximately 12 transformers per year as they fail.	• Maximize the useful life of current transformers. • Potential for higher levels of unplanned outages due to transformer failures.
25% proactive replacement ***$0.42*** *more on monthly bill by 2030*	Proactively replace 275 transformers by 2029 (55 per year).	• Accelerate transformer changes to meet anticipated demand for electricity. • Potential for reduced rate of unplanned outages due to transformer failures.
50% proactive replacement ***$0.84*** *more on monthly bill by 2030*	Proactively replace 550 transformers by 2029 (110 per year).	• Further accelerate transformer changes to meet anticipated demand for electricity. • Potential for reduced rate of unplanned outages due to transformer failures.

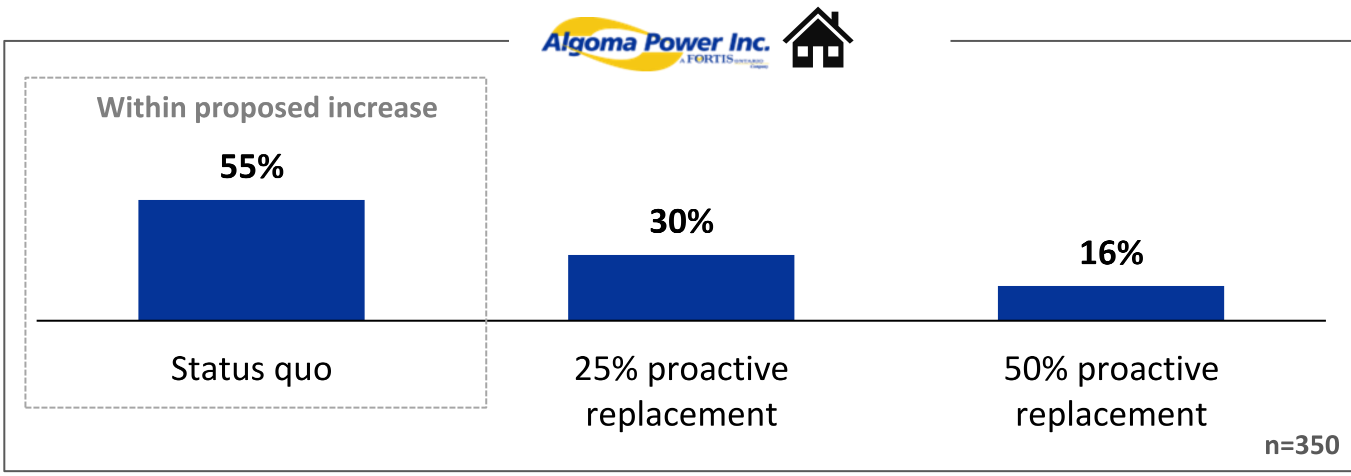
Additional Feedback (Optional)

Online Workbook

Seasonal

Choice 4: Preparing for increased electricity demand

Q Which of the following options do you prefer?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Status quo	60%	48%	53%	59%	61%	45%
25% proactive replacement	26%	35%	27%	27%	27%	38%
50% proactive replacement	14%	17%	20%	14%	12%	16%

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Online Workbook

Choice 4: Preparing for increased electricity demand

Seasonal

Q Which of the following options do you prefer?

Additional Comments	%
Transition to EV/alternatives not practical in the area	1.0%
Find efficiencies from within/upgrades should have been planned into budget	0.9%
Need more information/have questions	0.7%
Not all customers should pay for specific upgrades/area based	0.6%
Be proactive with the replacements	0.5%
Biased survey/designed to illicit specific responses	0.4%
Other	0.2%
No answer	95.7%

Note: Only responses >0.1% shown

Online Workbook

Seasonal

Planning for the Future: 2025-2029 Rate Application

Automated “intelligent” switches

Background: Technology has changed the way that Algoma Power can manage and monitor the distribution system.

Strategically located automated switches can help Algoma Power remotely monitor and trace power outages and re-route electricity from a control room rather than sending a repair crew to patrol the lines. This is made possible by both a) a physical automated “switch” often mounted on a pole that allows Algoma Power to easily locate an outage and b) computer software that allows that automated “switch” to be flipped remotely and re-route power.

Current Approach: Currently, Algoma Power has strategically employed “intelligent” automated switches in various parts of its service territory. When an outage occurs in an area without this automated technology, it can take crews between 4 and 8 hours to locate the issue, fix it and restore power.

By installing only an automated switch in an area, outage restoration times can be reduced by nearly half.

When an automated switch and the accompanying software is installed, an outage that would otherwise take 4-8 hours to restore could be reduced to less than one hour.

As with anything, there are costs associated with rolling out this technology more broadly.

2025-2029 proposed approach: In its current draft plan, Algoma Power is proposing to roll out the installation of automated switches and the associated software along a major line that serves approximately 6,200 customers east of Sault Ste. Marie.

That said, depending on customer feedback, Algoma Power could continue with the status quo and install no new additional switches, or they could defer some of the software upgrades to a later period, therefore reducing the bill impact for customers.

Online Workbook

Choice 5: Automated “intelligent” switches

Seasonal

Which of the following options do you prefer?

Option	Automated Switches	Expected Outcome
Status Quo ***$0.37*** *less on monthly bill by 2030*	No additional automated switches or software purchased and installed.	Across this stretch of the system, Algoma Power continues to manually locate outages and restore power, typically taking between 4 and 8 hours on average.
Partial Implementation ***$0.18*** *less on monthly bill by 2030*	• Install remotely controllable automated switches on a major line east of Sault Ste. Marie that serves 6,200 customers. • Defer the purchase and installation of software to 2030 and beyond.	Across this stretch of line, Algoma Power will be able to remotely locate an outage, improving average estimated restoration times by about 50%.
Full Implementation *Within proposed rate increase*	• Install both the remotely controllable automated switches and associated software on the major line east of Sault Ste. Marie. • Once software has been installed once, it can be rolled out across the system in the future.	Same benefits of partial implementation, however, outage restoration times are reduced even further because power can be restored remotely.

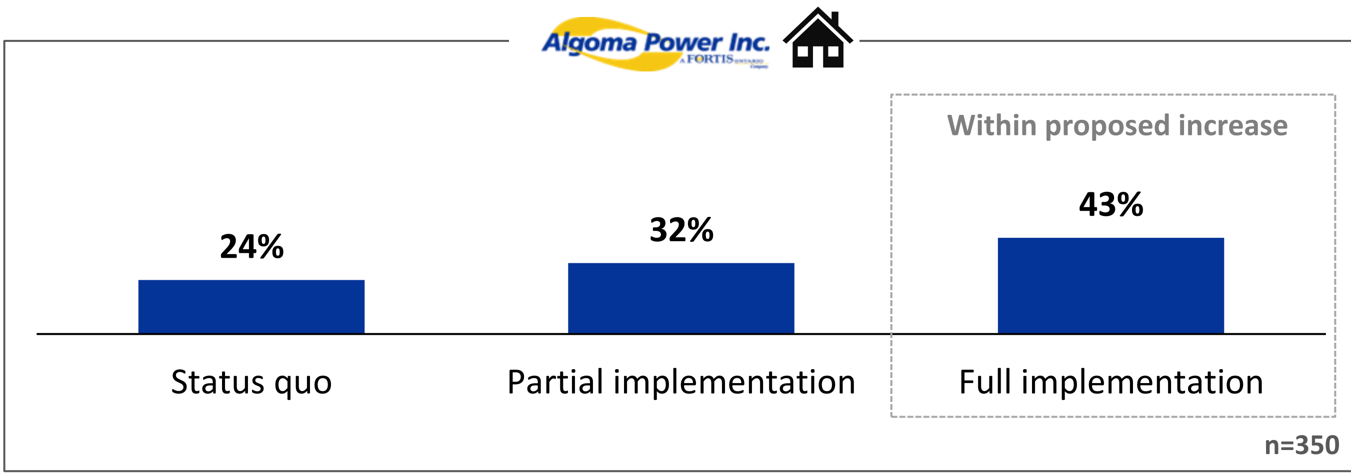
Additional Feedback (Optional)

Online Workbook

Choice 5: Automated "intelligent" switches

Seasonal

Q Which of the following options do you prefer?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Status quo	29%	18%	20%	26%	28%	24%
Partial implementation	32%	32%	32%	33%	35%	28%
Full implementation	39%	49%	47%	42%	37%	48%

Online Workbook

Choice 5: Automated “intelligent” switches

Seasonal

Q Which of the following options do you prefer?

Additional Comments	%
Willing to pay more for reliable service	1.0%
Only those customers/areas affected should pay the cost	0.6%
Lower rates/no increase/cost too high already/keep it affordable	0.5%
Against the installation of automated switches	0.3%
Need more information/have questions	0.2%
No answer	97.4%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Online Workbook

Seasonal

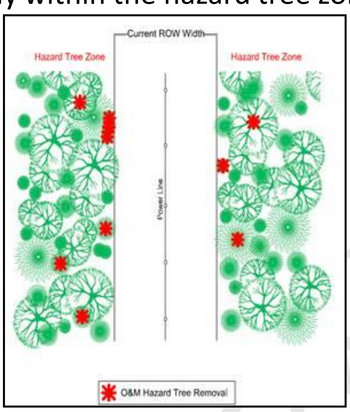
Planning for the Future: 2025-2029 Rate Application

Vegetation Management

Background: Between 2018 and 2022, tree contacts have contributed to 35% of all customer outages, as measured by the total number of hours without power. While tree caused outages have significantly declined over the years through Algoma Power's Vegetation Management Program (VMP), trees remain the biggest contributor to customer power outages. As 85% of Algoma Power's powerlines have a treed (forested) edge, the most common cause of power interruptions are tree related and require crews to be dispatched to make repairs and restore power.

Current approach: Algoma Power continues to manage vegetation in proximity to powerlines to reduce the risk of tree exposure and limit the occurrence of tree caused outages. Work activities including trimming and removal of trees are part of scheduled maintenance practices used to manage vegetation (trees and brush) that can fall or grow into the powerlines.

To mitigate these risks, Algoma Power's VMP takes a preventative approach using condition assessments to determine priority work. Priority work is largely based on tree health, growth, and impact to service interruptions. To date, priority work is a main contributor to the reduction in tree caused outages, particularly within the hazard tree zone (see diagram below).



2025-2029 proposed approach: In its current draft plan, Algoma Power is proposing to continue with its historical approach of preventative maintenance to reduce the potential of tree caused outages across the service territory. While this would result in similar reliability outcomes to the past, the rapid improvements to reliability would likely slow down.

To further reduce costs, Algoma Power is also considering reducing the frequency of assessing and removing declining trees that occurs within this "hazard tree zone". Reducing this assessment would ultimately increase the risk that a tree in poor condition is missed and could therefore come into contact with a powerline.

On the other hand, Algoma Power could also increase its assessment in this area, further reducing the likelihood of a tree contact, even relative to today's standards. This is where Algoma Power wants to hear from you.

Online Workbook

Choice 6: Vegetation Management

Seasonal

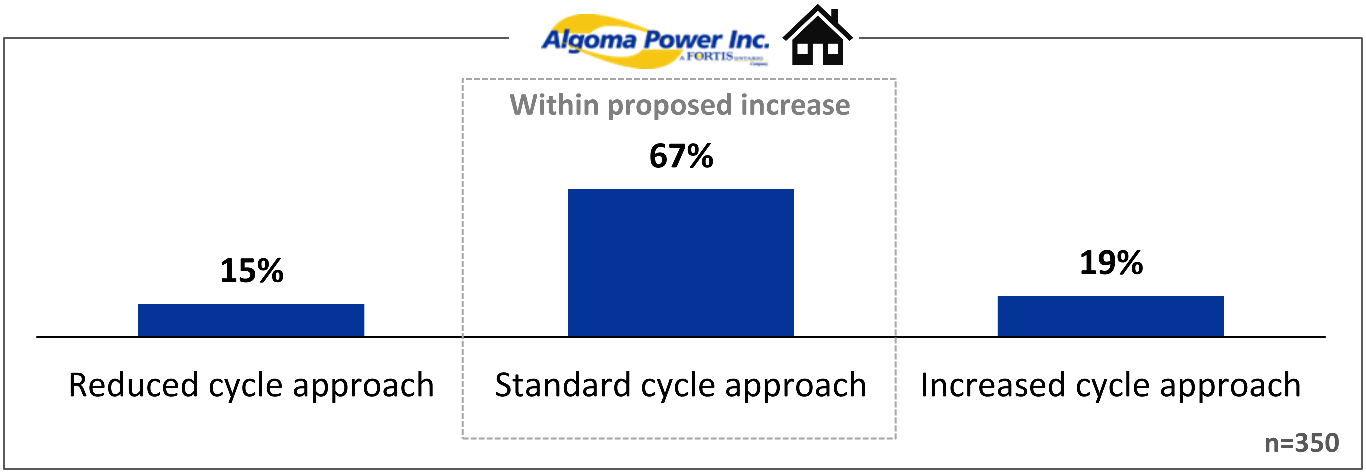
Which of the following options do you prefer?		
Option	Approach	Expected Outcome
Reduced Cycle Approach ***$0.78** less on monthly bill by 2030*	Reduce the level of "hazard tree zone" monitoring by 300 km per year.	• Increased exposure of hazard trees to the powerlines • Potential for decreased reliability resulting from increased exposure of the hazard trees.
Standard Cycle Approach *Within proposed rate increase*	Status Quo, continue with historical approach.	• Similar trend in reliability performance relative to the past 5 years
Increased Cycle Approach ***$0.78** more on monthly bill by 2030*	Increase the level of "hazard tree zone" monitoring by 300 km per year.	• Decreased exposure of hazard trees to the powerlines • Potential for increased reliability performance resulting from reduced exposure of the hazard trees.
Additional Feedback (Optional)		

Online Workbook

Choice 6: Vegetation Management

Seasonal

Q Which of the following options do you prefer?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Reduced cycle approach	15%	14%	17%	19%	12%	12%
Standard cycle approach	65%	69%	65%	69%	70%	62%
Increased cycle approach	20%	17%	18%	12%	18%	26%

Online Workbook

Choice 6: Vegetation Management

Seasonal

Q Which of the following options do you prefer?

Additional Comments	%
Against healthy tree removals/cutting	1.1%
Preventative maintenance of trees helps with outages	1.1%
Customers to alert Algoma Power of tree issues/hazards	0.8%
Consider other approaches (tree topping)	0.6%
Power lines have been fine/clear	0.6%
Need more information/have questions	0.5%
Find efficiencies from within/upgrades should have been planned into budget	0.2%
Lower rates/no increase/cost too high already/keep it affordable	0.2%
No answer	94.9%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Impact of Choices

Do You Want to Change Your Choices?

Seasonal

Impact of Choices

Investment alternative summary

Throughout this workbook, you have been asked about 6 key choices that could impact your rates. Below is a summary of your answers to those questions.

At the bottom of this page, you will find an estimated total bill impact based on all your answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential rate impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Seasonal Customer Bill Impact Change and Magnitude of Bill Impact **(MEAN)**

Range of Impacts

-$2.14 to +$3.23

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 **$3.23 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 **$2.14 less** per month by 2030 when compared to the draft plan.

INNOVATIVE RESEARCH GROUP

Impact of Choices

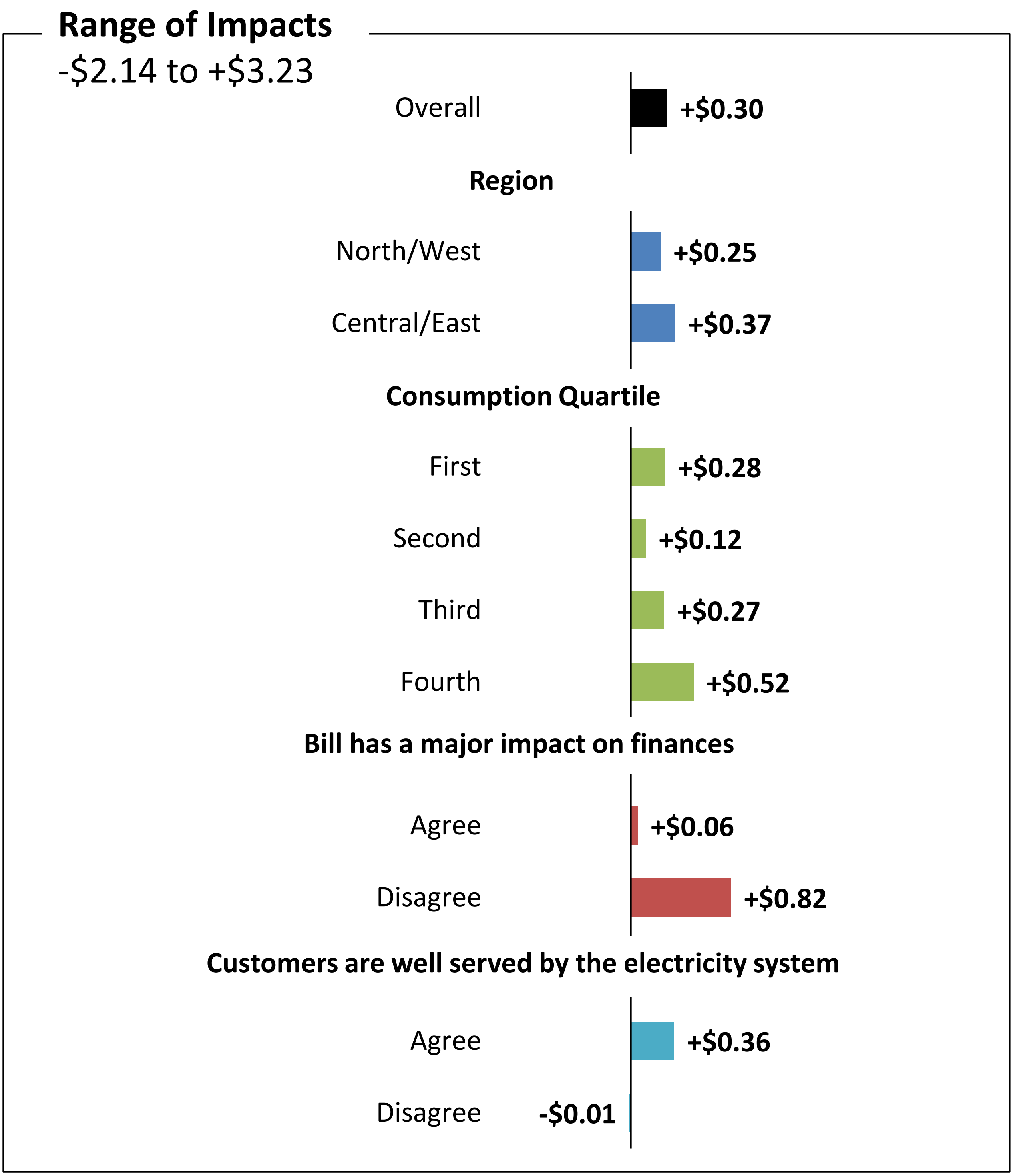
Do You Want to Change Your Choices?

Seasonal

Impact of Choices

Investment alternative summary

Seasonal Customer Final Magnitude of Bill Impact BY key segments **(MEAN)**

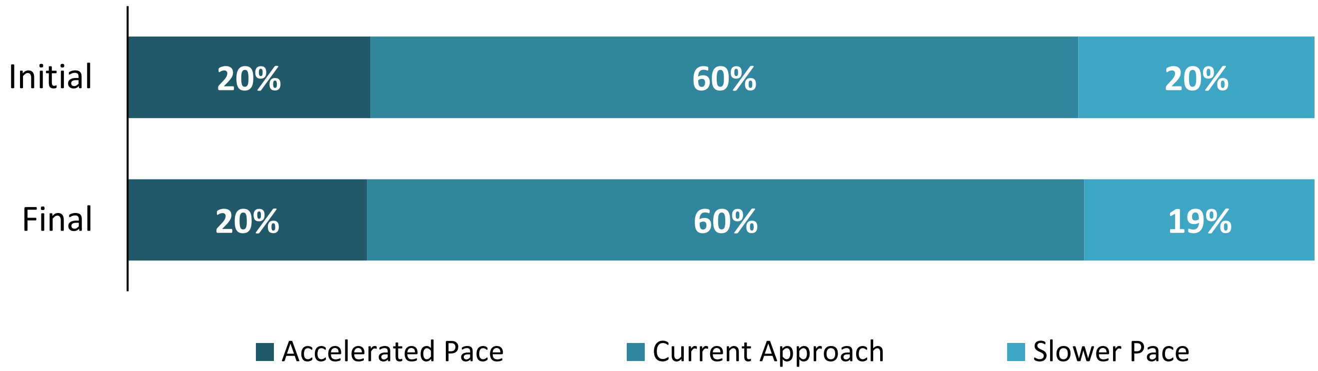


Making Choices

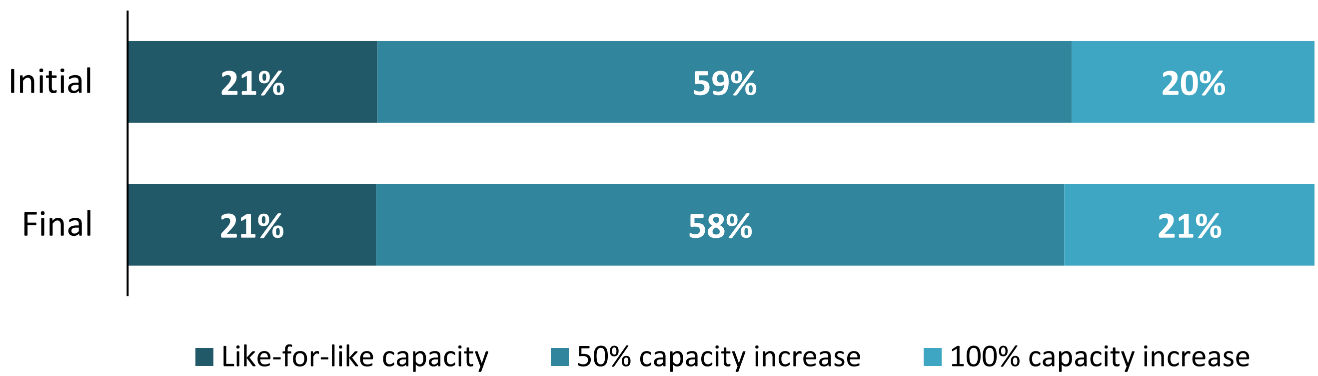
Impact of Choices

Seasonal

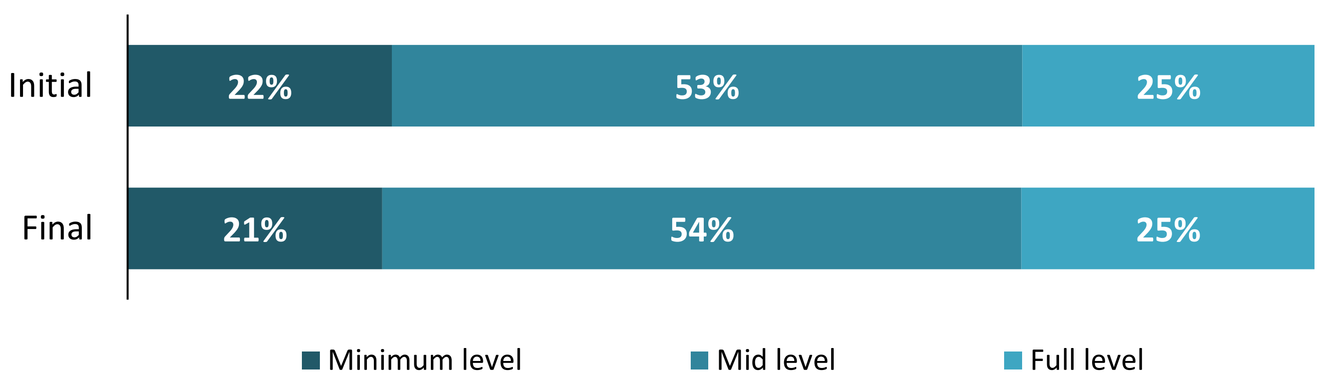
Pole and Line Replacement



Substation Rebuild



Voltage Conversion

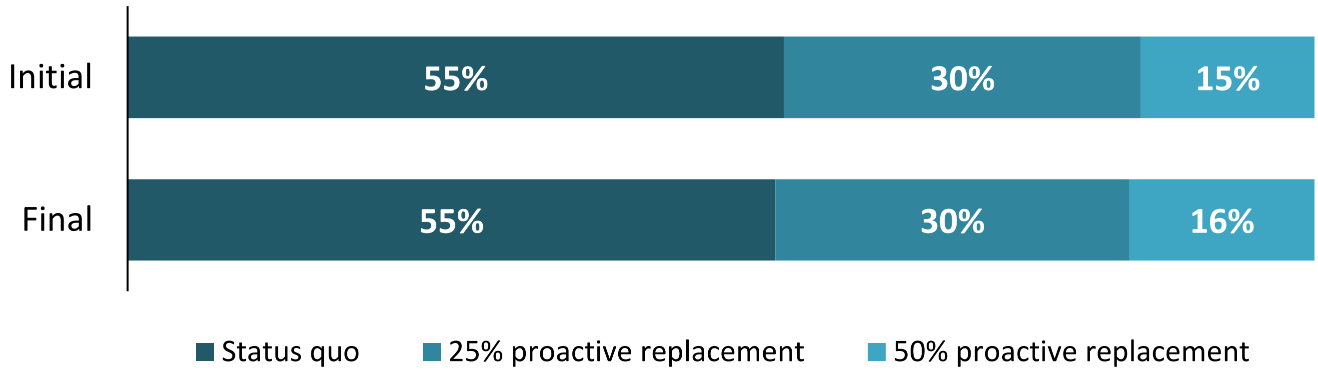


Making Choices

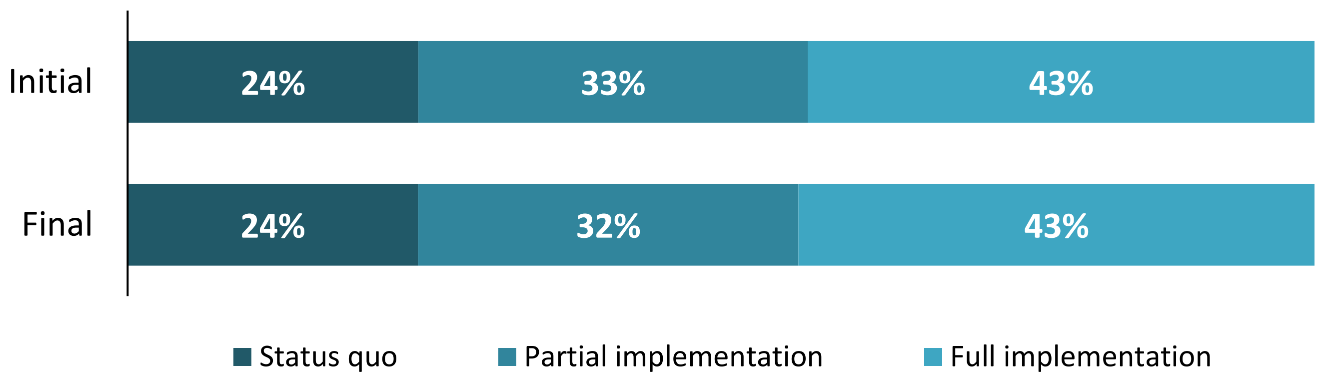
Impact of Choices

Seasonal

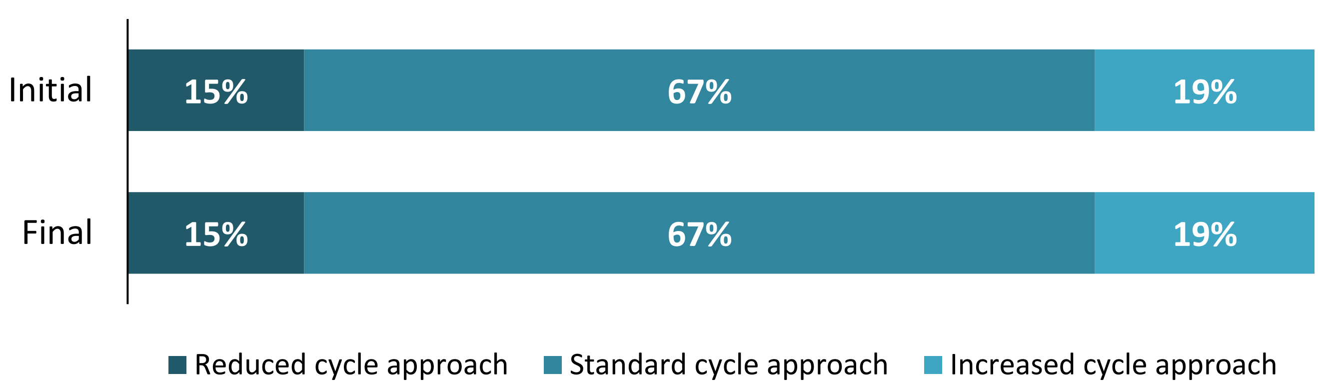
Preparing for increased electricity demand



Automated “intelligent” switches



Vegetation Management



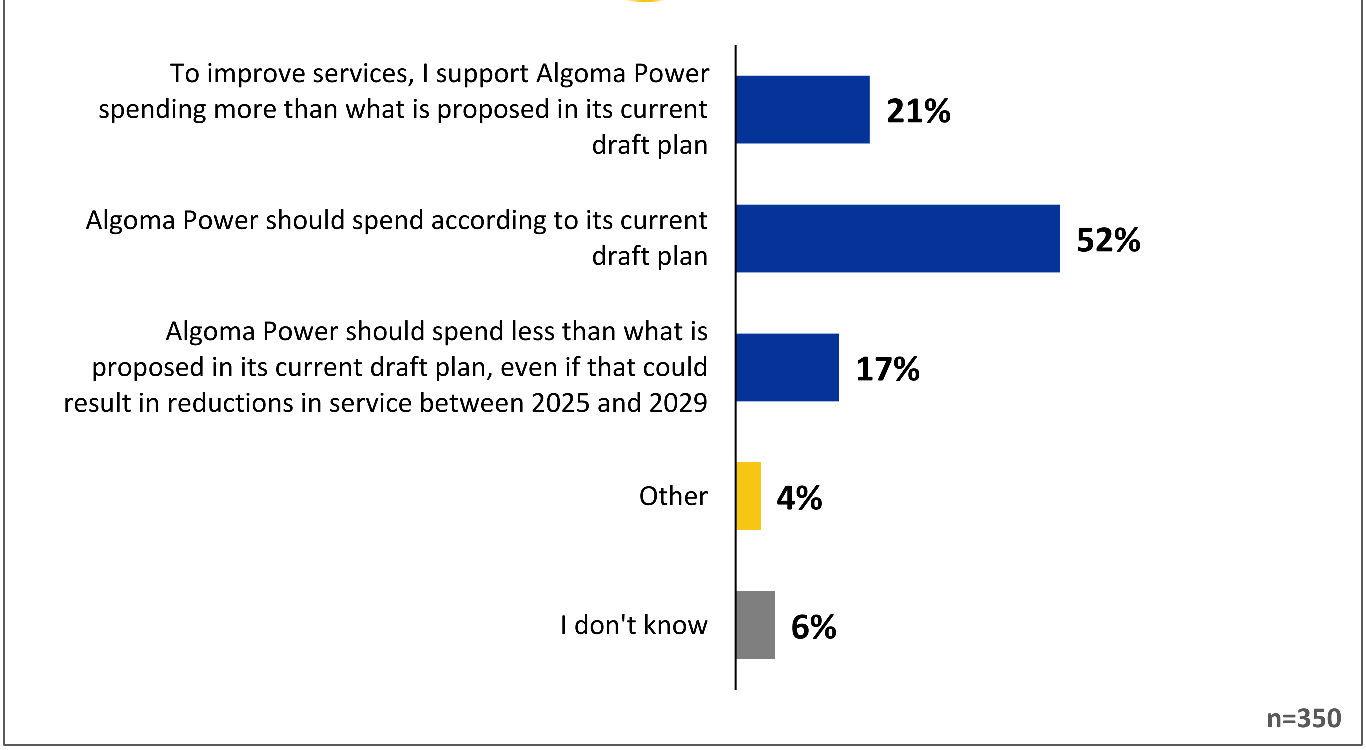
Online Workbook

Overall Plan Evaluation

Seasonal

Q Algoma Power has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Algoma Power would like to know how you feel about the draft plan.

Considering what you have learned about Algoma Power's 2025–2029 draft plan, which of the following best represents your point of view?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Spend more	18%	26%	20%	19%	23%	24%
Spend according to plan	54%	48%	52%	49%	53%	53%
Spend less	16%	17%	21%	17%	16%	12%

Online Workbook

Seasonal

Final Comments about Algoma Power’s draft plan for 2025–2029

Q Do you have any final comments regarding Algoma Power’s draft plan for 2025–2029 and the proposed rate increase?

Additional Comments	%
Concerns with seasonal rates/same rate across all customers	8.6%
Need more information/answer questions/concerns	2.2%
Decrease distribution/delivery charges/high rates/costs	2.2%
Support the proposed rate increase/investments are necessary	1.6%
Affordability/Keep cost low	1.3%
Concerns of increases due to the high cost of living/inflation	1.3%
Draft plan/approach is reasonable	1.0%
Concerns/skeptical about the draft plan/choices/survey	0.8%
Be proactive/responsible/prepare for the future/improve grid	0.8%
Algoma Power will do what they want/won't listen to customers	0.6%
Focus on environmental/sustainable concerns/practices	0.6%
Discounts for seniors/low-income/long time customers	0.4%
Find efficiencies from within/upgrades should have been planned into budget	0.2%
Appreciate informing/educating customers of the plan/approaches/choices	0.2%
Satisfied with service/Great work	0.2%
Improvements should be paid by Algoma Power (profits)	0.2%
Other	0.3%
None	77.5%

Note: Only responses >0.1% shown

INNOVATIVE
RESEARCH GROUP

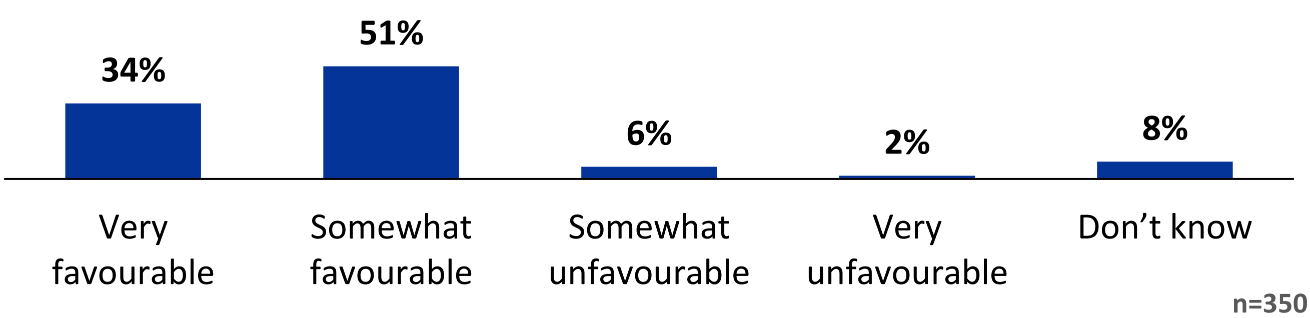
Seasonal Customers
Workbook Diagnostics

Online Workbook

Workbook Impression

Seasonal

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



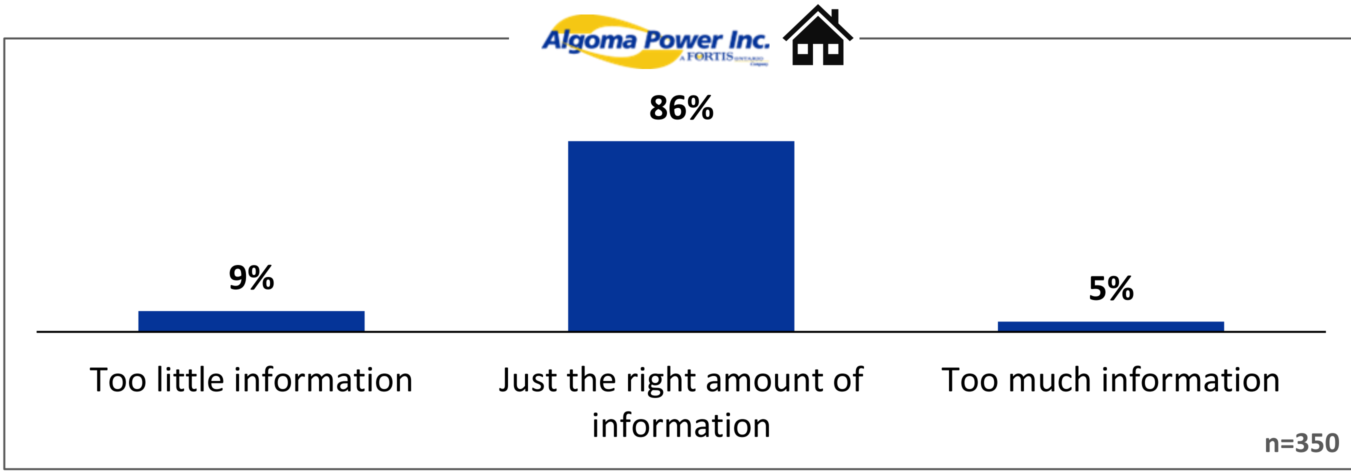
	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Very favourable	37%	30%	37%	29%	38%	33%
Somewhat favourable	45%	59%	55%	52%	43%	54%
Somewhat unfavourable	7%	4%	3%	7%	7%	5%
Very unfavourable	2%	1%	1%	1%	2%	2%
Don't know	9%	6%	3%	12%	10%	6%
Favourable (Very + Somewhat)	**82%**	**89%**	**93%**	**80%**	**80%**	**87%**
Unfavourable (Very + Somewhat)	**9%**	**5%**	**4%**	**8%**	**9%**	**7%**

Online Workbook

Amount of Information

Seasonal

Q In this customer engagement, do you feel that Algoma Power provided too much information, not enough, or just the right amount?



	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Too little information	8%	11%	4%	11%	12%	10%
Just the right amount	86%	86%	91%	87%	84%	81%
Too much information	6%	3%	4%	1%	4%	9%

Online Workbook

Content Missing from Engagement

Seasonal

Q Was there any content missing that you would have liked to have seen included in this customer engagement?

Additional Comments	%
Addressing seasonal rates/costs/concerns	6.8%
Breakdown/clear explanation of charges/rates/comparison to other utilities	2.6%
Survey issues - too long/too many words/complicated language/more videos	1.4%
Plans to reduce/lower consumer cost/rates/fees	1.4%
Helping seniors/low income households	1.1%
Transparency on operations/revenue/spending/management salaries/investments	1.1%
Consumption/conservation efforts information/incentives	0.9%
Alternative/green energy plans/info - solar, wind effectiveness/costs	0.8%
Appreciative of being heard/wanting customer input	0.7%
Reasons for outages/area specific info	0.6%
More information/details/statistics	0.5%
Condense the information/too much information	0.4%
Impact of EV on the grid/explanation of increased demands	0.3%
Survey was educatonal/informative	0.3%
Proper arrangements of tree removal/cutting	0.3%
Government interference/involvement	0.2%
Replacing poles vs putting lines underground	0.2%
Other	1.0%
Don't know	78.0%
None	1.4%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Small Business Customers

Online Workbook Results

Online Workbook
Survey Design & Methodology

INNOVATIVE was engaged by Algoma Power Inc. to gather input on their proposed draft 2025-2029 business plan. Throughout this report, actual pages of the workbook that customers completed are included in the order that they were seen and are indicated by a watermark that says, “workbook page”.

Field Dates & Workbook Delivery

The **Small Business (GS<50) Online Workbook** was sent to all Algoma Power small business customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **December 4th, 2023 and January 1st, 2024**.

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

In total, the small business workbook was sent to **696** customers via e-blast from INNOVATIVE. Two additional reminder emails were sent to those who had not yet completed the workbook in order to encourage participation and maximize response.

Small Business Online Workbook Completes

A total of **35** (unweighted) Algoma Power small business customers completed the online workbook via a unique URL.

Sample Weighting

Due to the small sample size, the sample for Algoma Power’s small business customers has not been weighted. Throughout the report, results are represented in frequencies rather than percentages.

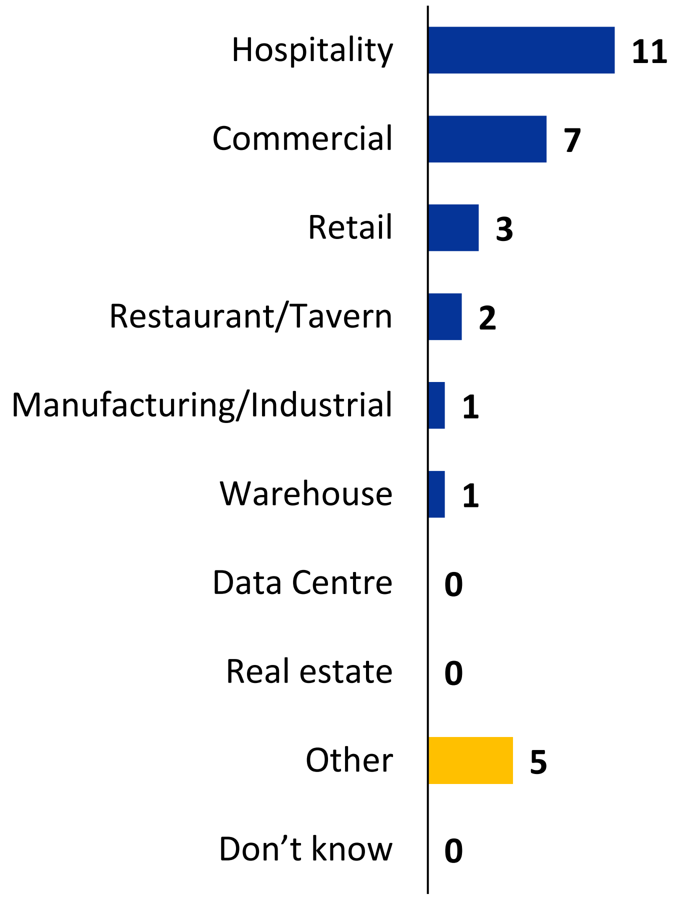
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Workbook

Firmographic breakdown

Small Business

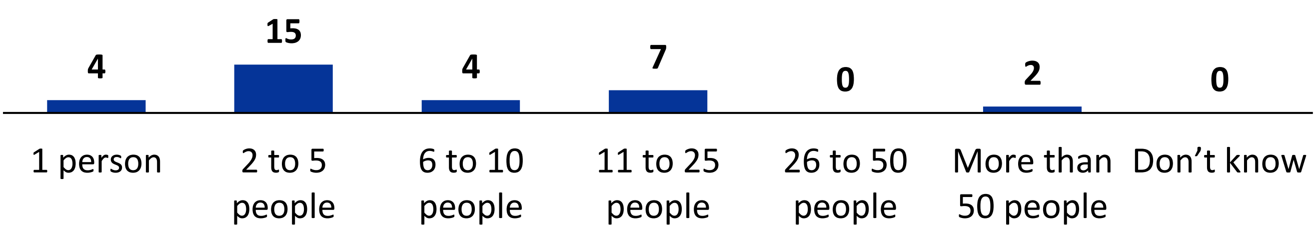
Q Business Sector



“Prefer not to say”(5) not shown.

n=35

Q Number of Employees



“Prefer not to say”(3) not shown.

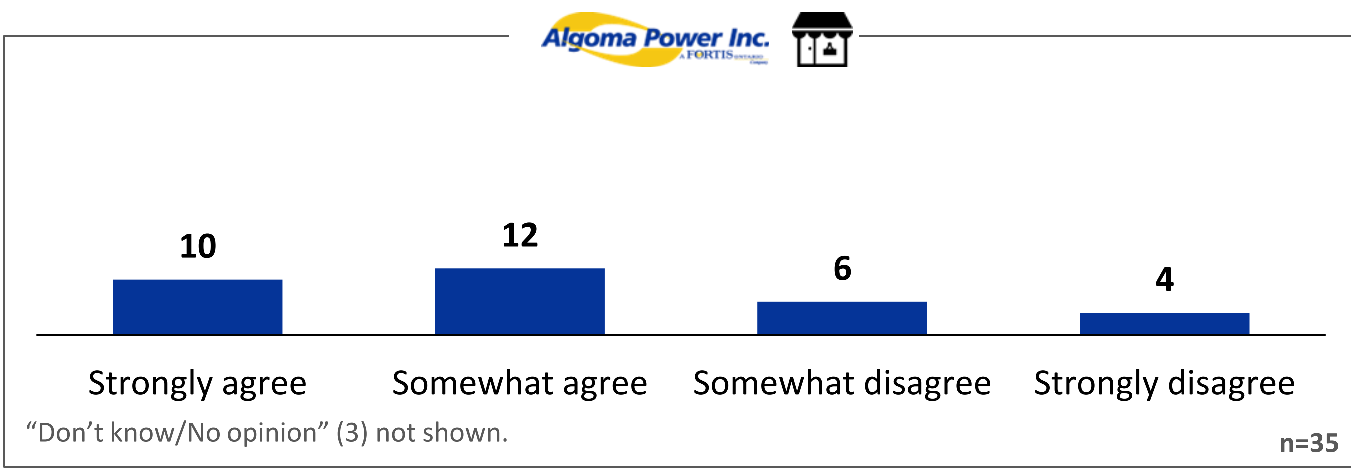
n=35

Online Workbook
Environmental Controls

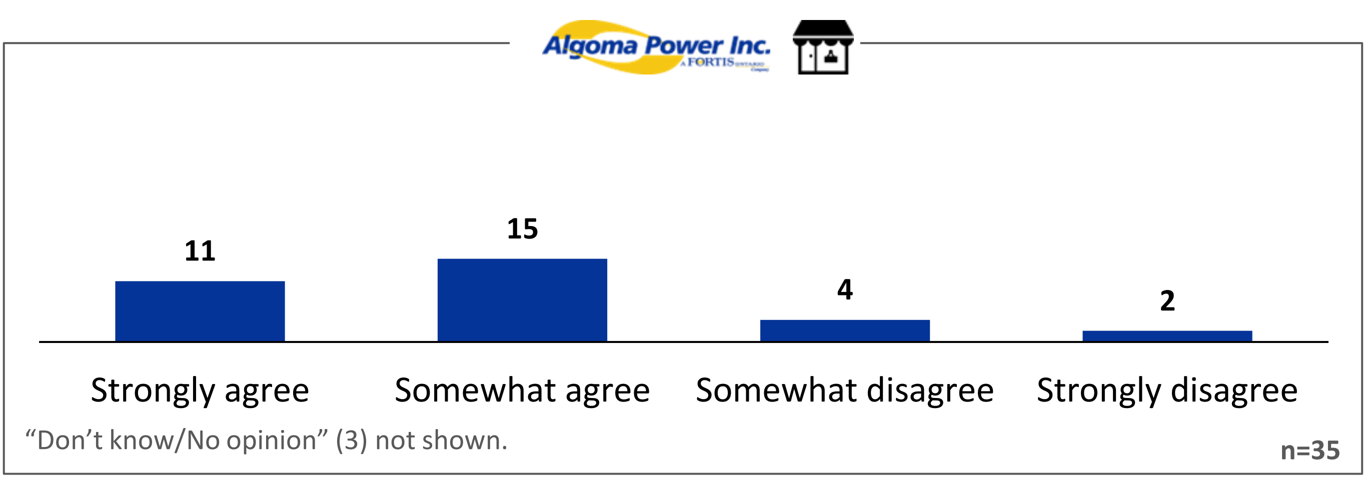
Small Business

Now we would like to shift the focus and ask you some general questions about the electricity system in Ontario. To what extent do you agree or disagree with the following statements?

Q 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.



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



Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

About this Customer Engagement

Welcome to Algoma Power's customer engagement survey!

Over the course of the past year, Algoma Power has been developing its 2025-2029 business plan.

- **Today, Algoma Power is looking for your input on its draft plan** to ensure it is making spending decisions that matter to you, the customer.
- **In early 2024, Algoma Power plans to justify and present** its business plans to the public regulator, the Ontario Energy Board (OEB).
- **Beginning in 2025, based on the OEB's approval, Algoma Power will be updating the rate that you pay** for the delivery of electricity to your home or business.

This survey will take approximately 20 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved and you can return to the customer engagement at any time.

Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback and protect your confidentiality.

Those who complete the questions that follow will be invited to enter a draw to win one (1) of two (2) $500 VISA gift cards.

We thank you for your valuable time.

While the survey can be completed on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop computer, or laptop instead so that it is easier for you to read.

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

About this Customer Engagement

What do we want to talk about?

Today's engagement will focus on two key areas while also allowing you to "colour outside the lines" and tell us what you think more broadly.

1. First, this engagement will seek to understand **what you feel Algoma Power should be prioritizing** over the next five years.

2. Next, you will be asked some questions about **specific investment decisions Algoma Power needs to make** related to overhead poles, wire, and other critical infrastructure.

But first, we need to ensure that we are all on the same page regarding Algoma Power's role in the broader electricity system, how much of your bill goes to Algoma Power, and where that money goes.

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

Electricity 101

Algoma Power's role in Ontario's electricity system

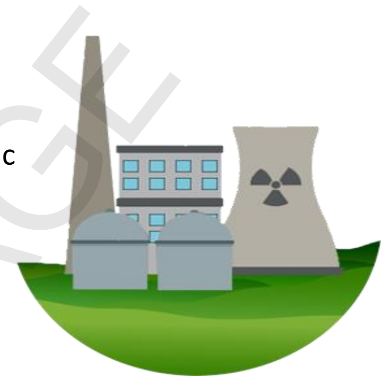
Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources. More than half comes from nuclear power. The remainder comes from a mix of hydroelectric and natural gas, and to a lesser extent, wind and solar.

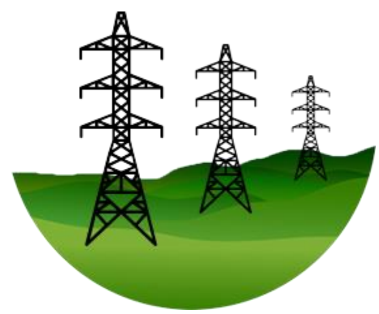
Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from multiple generators who have contracts with the grid operator to provide power from a variety of sources.



Transmission

How electricity travels across Ontario

Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which are owned and operated by Hydro One.



Local Distribution

How electricity is delivered to the end-consumer

Algoma Power is responsible for the last step of the journey: distributing electricity to customers through its distribution system.

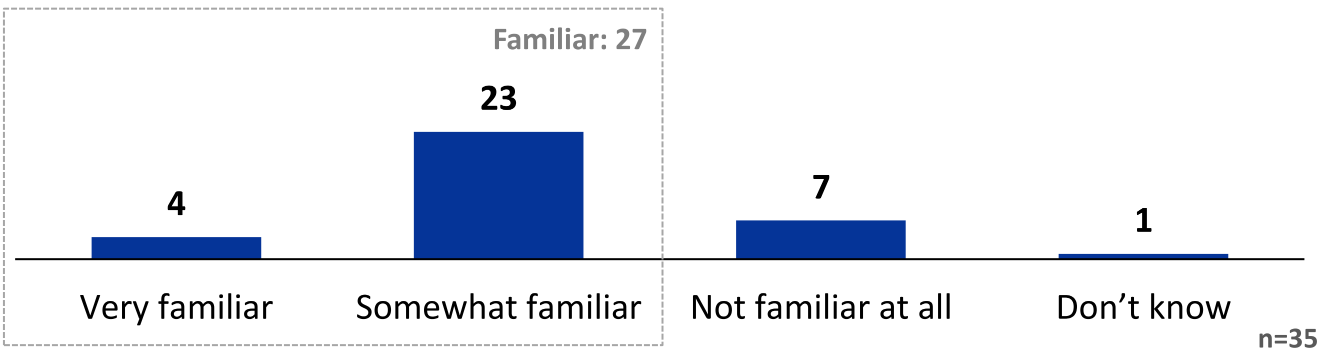
- Algoma Power manages all aspects of the electricity distribution business throughout the Algoma District of northern Ontario.
- In your community, amongst other functions, Algoma Power is responsible for:
    - Building and maintaining the local electricity distribution system
    - Responding to outage calls 24/7
    - Reading meters
    - Producing bills and accepting bill payments

Online Workbook

Familiarity with Algoma Power

Small Business

Q Before this survey, how familiar would you say you were with Algoma Power and the role it plays in Ontario's electricity system?



Online Workbook

Small Business

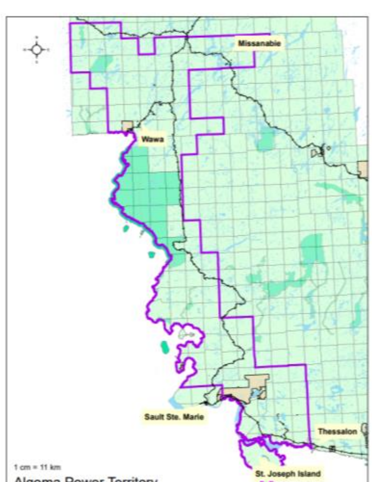
Planning for the Future: 2025-2029 Rate Application

Electricity 101

Who is Algoma Power?

Algoma Power services in the remote areas of Northern Ontario, extending 93 km east and approximately 340 km north of the City of Sault Ste. Marie, for a total of 14,200 km^2 of service territory, the second largest in Ontario.

- **Algoma Power does not generate or transmit electricity** — it owns and operates the local electricity system.
- **Algoma Power services about 12,000 customers,** over 14,200 km^2, making it the lowest-density distributor in Ontario. As a result of the low number of customers in such a large area, the cost to provide service to each customer on average is higher, as Algoma Power must install more equipment (ex: longer lines) to provide service to each customer.
- **Historically, much of Algoma Power's distribution system was built to service the resource sector and the communities that developed around those enterprises**. As a number of those industries declined or relocated, the result is a sparsely populated service territory with predominantly Seasonal and seasonal customers.
- **As with all other local distribution companies in Ontario, Algoma Power is funded by the distribution rates that you pay on your electricity bill**. Unlike most other utilities, a portion of this funding is recovered through other provincial funds intended to manage the affordability of distribution rates for rural and remote customers.
- As a local distribution company (LDC) and regulated entity, **Algoma Power can only charge the rates the regulator approves to charge for its services.**
- **The OEB runs an open and transparent review process** where experts from the regulator and intervenor groups review and challenge Algoma Power's analyses and assessments.



Algoma Power Territory

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

Electricity 101

How much of my organization's electricity bill goes to Algoma Power?

- Every item and charge on your organization's bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While Algoma Power is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge. The delivery charge also includes Hydro One transmission costs and system losses.
- **Distribution makes up about 26% of the typical small business customer's bill, excluding the Ontario Electricity Rebate (OER) and Harmonized Sales Tax (HST).**
- The distribution portion of your organization's bill, which goes towards operating and maintaining Algoma Power's distribution system, is largely fixed. Meaning, it does not change depending on how much electricity your organization uses.
- The rest of your organization's bill payment is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

Sample Algoma Power Monthly Bill

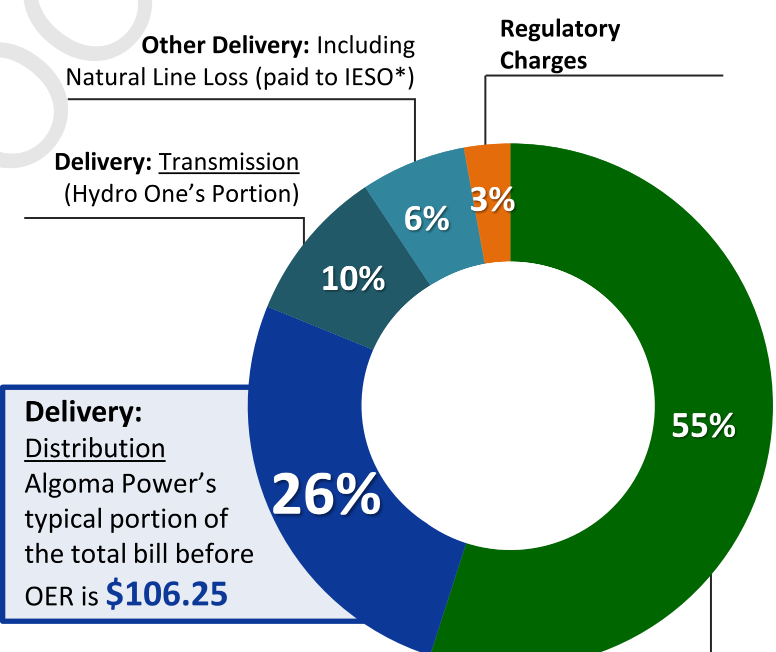
(based on consumption of 2,000 kWh as of Nov. 1, 2023)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges

Electricity	
On-Peak (highest price) @ 18.2 c/kWh	69.12
Mid-Peak (mid price) @ 12.2 c/kWh	43.92
Off-Peak (lowest price) @ 8.7 c/kWh	109.62
Delivery	171.08
Regulatory Charges	11.51
Total Electricity Charges	**$405.30**
HST	52.69
Ontario Electricity Rebate	**(-$78.22)**
Total Amount	**$379.76**



*IESO = Independent Electricity System Operator

Chart is based on total bill of $405.30 excluding the Ontario Electricity Rebate and HST. Chart may not total 100% due to rounding.

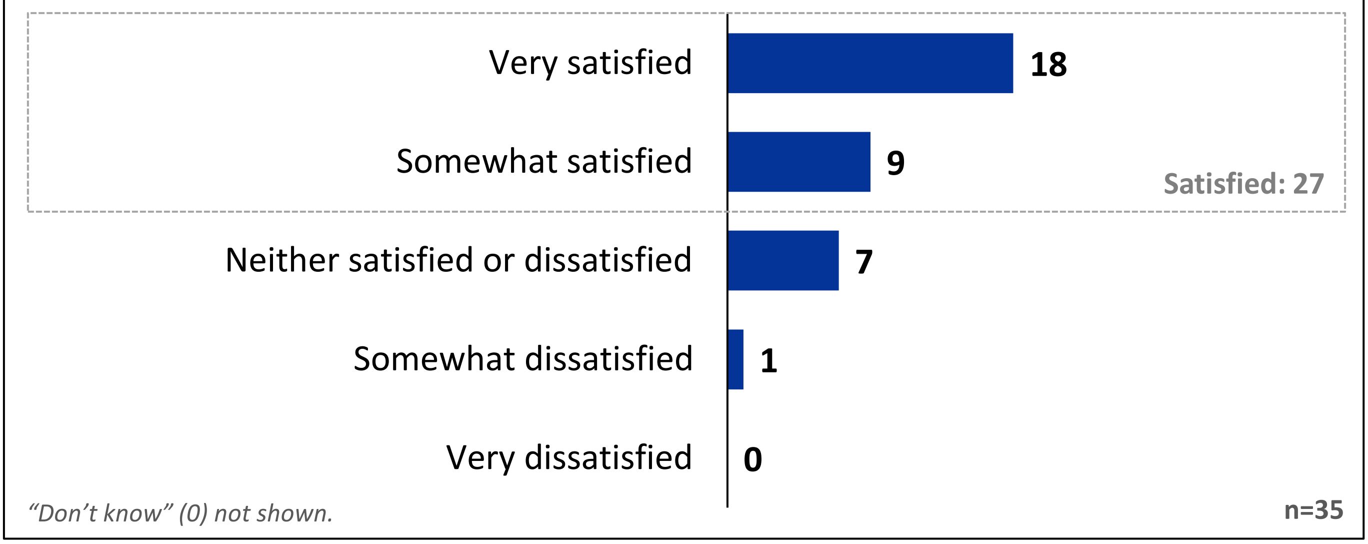
The sample bill above uses an average consumption level of 2,000kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

Online Workbook

Familiarity with Algoma Power

Small Business

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

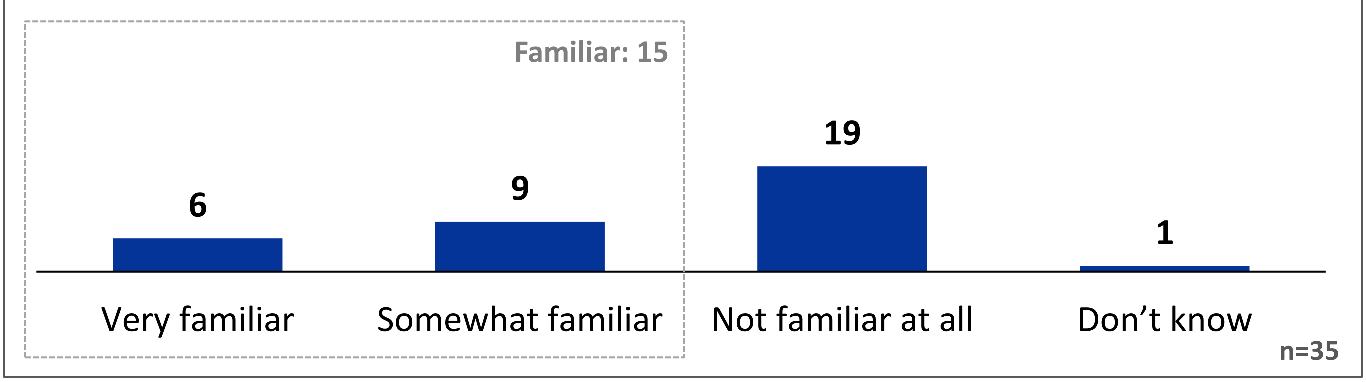


Online Workbook

Small Business

Familiarity with the Percentage of Bill Remitted to Algoma Power

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



Online Workbook

Small Business

How Algoma Power can Improve Services to Customers

Q Is there anything in particular you would like Algoma Power to do to improve its services to you?

Verbatim responses (optional)
"Yes, First Nation Indians should have a discount or be exempt from the HST not matter where they reside."
"less power outages!"
"the delivery charge is more than my usage"
"compensating individuals for planned outages, when the power goes off the grid, generators cost a fortune to run for the day"
"easier access to the online billing portal"
"delivery-charges"
"Lower price"
"Delivery charges make up more than 26% of most bills in rural areas. That is a significant extra cost and it would be better if that percentage could be reduced."
"Lower delivery fees"
"Cut our costs"
"do something about expensive delivery charge to places that use a few dollars of actual electricity."
"Reduce the number of spike outages or start being more responsible for damage to our sensitive electronics that are being damaged from these numerous 1-5 second spikes and power outage."
"Better, more timely communication during outages."

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

Electricity 101

Explaining Rural Remote Rate Protection

Algoma Power is one of seven different utilities in Ontario that have a largely rural customer base.

As a rural customer, your organization benefits from a government program that is designed to bring the distribution costs for rural and remote customers more in line with what urban customers pay for distribution.

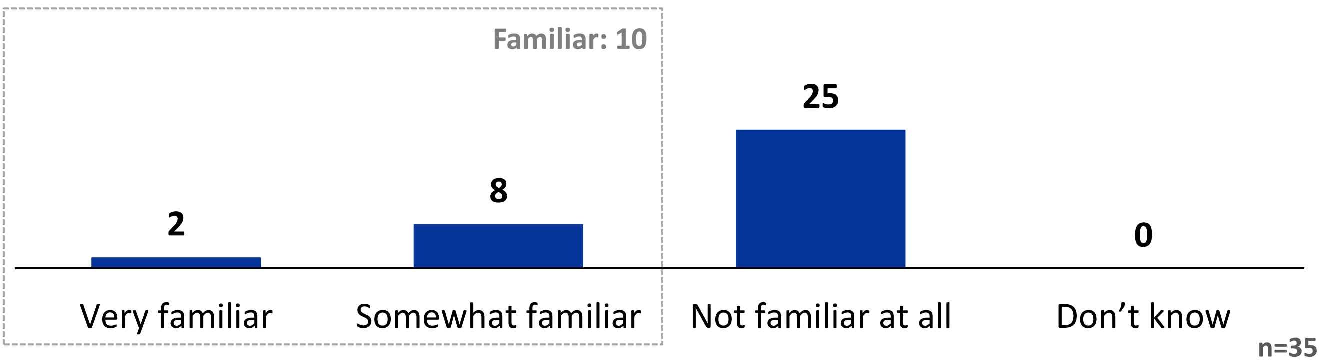
- As of this year, the maximum monthly base distribution charge has been set at **$106.25**.
- That means, as long as these protections remain in place, customers like yourself won't pay more than the maximum amount set by the program.

Online Workbook

Familiarity with Government Programs

Small Business

Q Before this survey, how familiar were you with this government program which applies to rural Algoma Power customers and caps the amount of distribution charges your organization pays?



Online Workbook

Setting Priorities within Algoma Power's Plans

Small Business

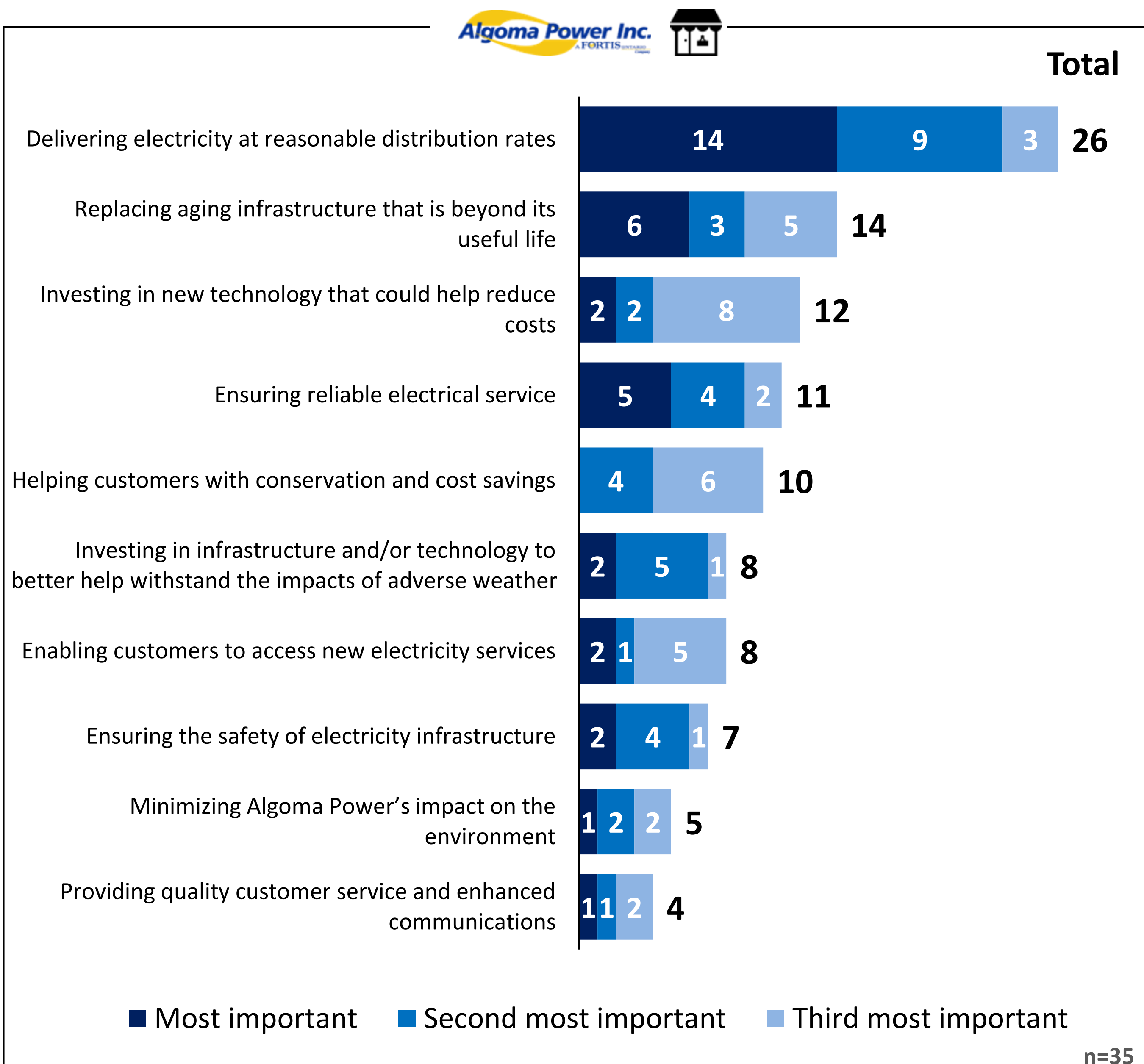
Q

As with all businesses, Algoma Power must make decisions on which areas they are going to prioritize within their business plans.

Based on ongoing conversations with customers, a number of company goals have been identified as priorities for Algoma Power.

Looking at the list below, please rank your top 3 priorities—where "1" would be the most important, "2" the second most important, and "3" the third most important.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, and ending with the third most important.



Online Workbook

Other Important Priorities

Small Business

Q Can you think of any other important priorities that Algoma Power should be focusing on?

Verbatim responses (optional)
“remote pricing”
“cut-delivery”
“Promote small generation systems like solar and mini hydro electric”
“delivering electricity at reasonable rates”

Note: Only responses >0.1% shown

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

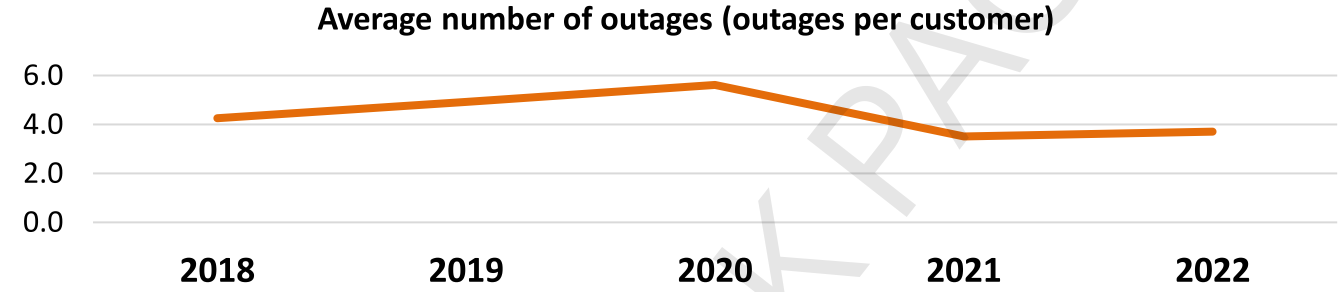
Background Context

Focus on Reliability

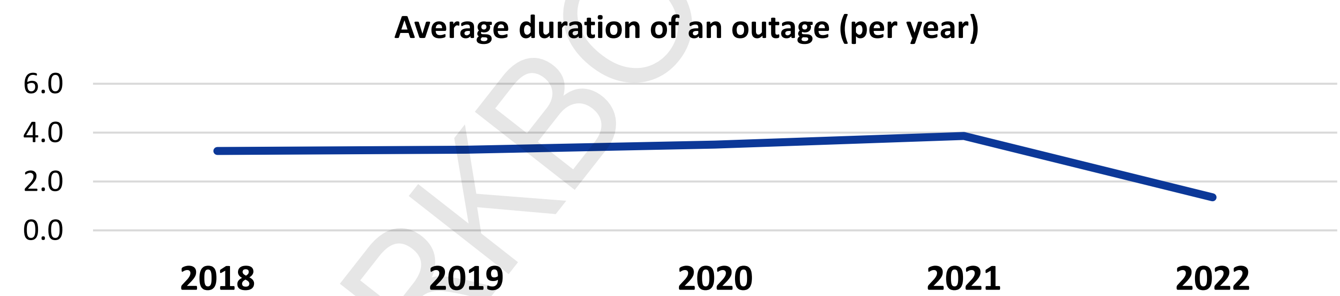
Since reliable electricity service is so important to customers, before we move on, we want to ask you about which specific areas you feel that Algoma Power should focus on over the next five years.

Algoma Power tracks both the **average number of power outages** per customer and **how long those interruptions last**.

Between 2018 and 2022, the typical Algoma Power customer has experienced about **4 and a half outages per year**.



Over the same period, the **average duration of an outage has been about 3 hours**. Meaning, when the power does go out, Algoma Power is typically able to restore power in about three hours.



It's important to keep in mind that these are system averages, and that your actual experience may be different.

- Generally speaking, the further away a customer is from the distribution substation, the more outages the customer will likely experience, as longer distribution lines have a higher probability of being damaged.
- Some customers connected to newer lines may not experience any outages, while others are experiencing more than the average number of outages each year.

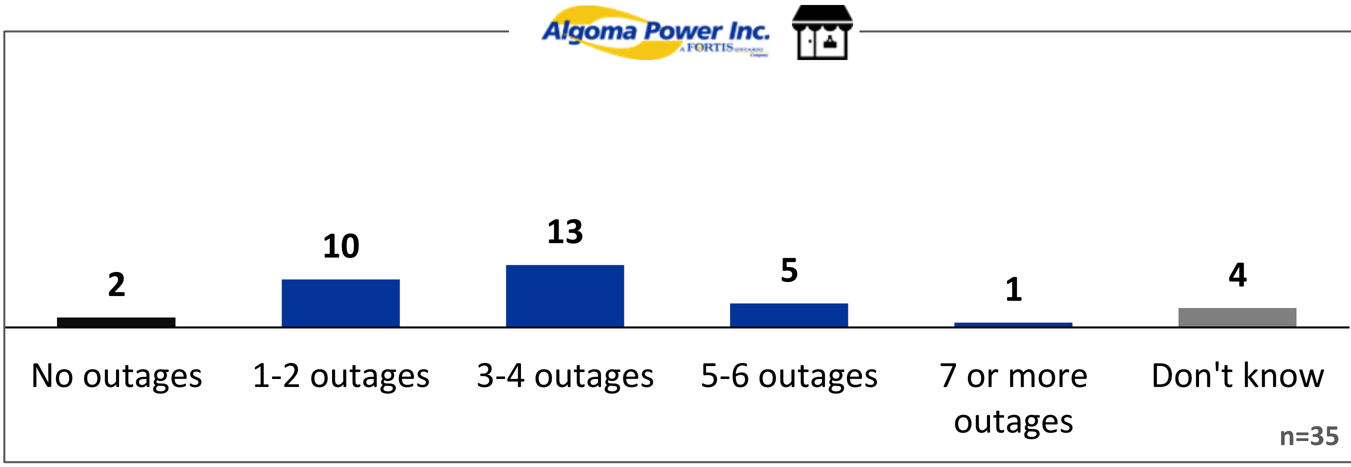
The tables and figures above include outages related to extreme weather events and transmission loss of supply events (which Algoma Power has relatively lower ability to control).

Online Workbook

Number of Outages Experienced

Small Business

Q Have you experienced any power outages as an Algoma Power customer in the past 12 months which lasted longer than one minute?



Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

Background Context

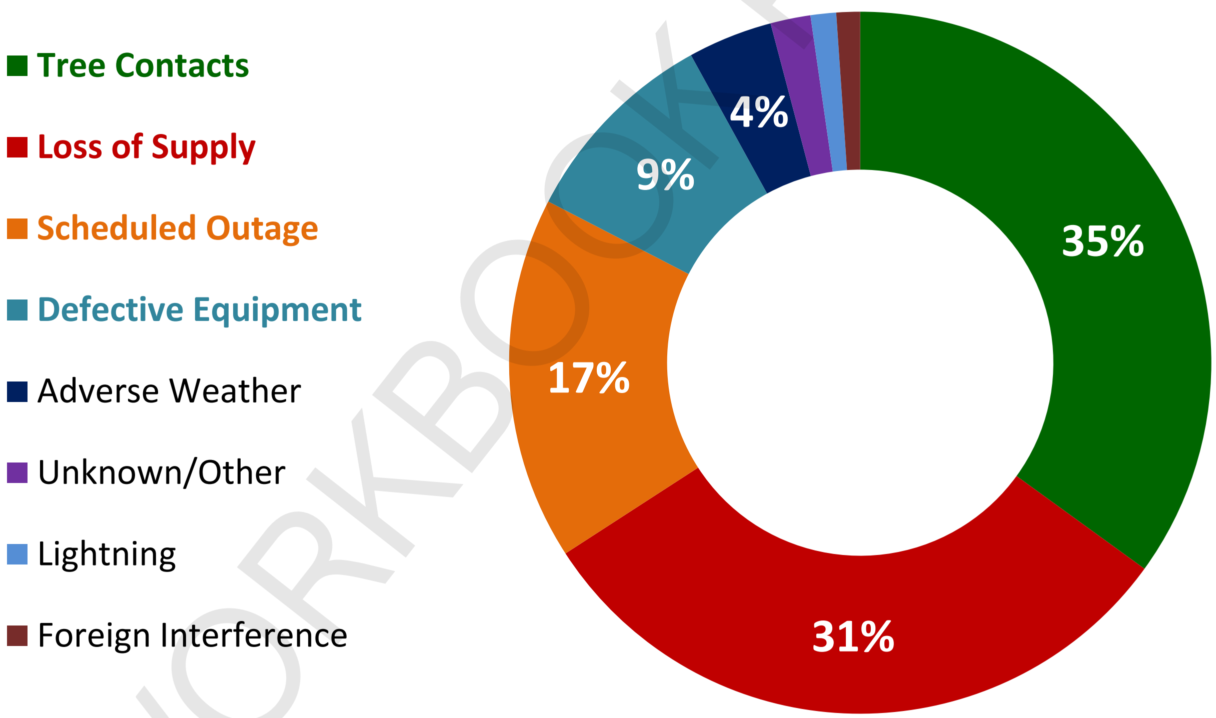
Focus on Reliability

Since 2018, 66% of all outages have been traced back to two causes – tree contacts (35%) and loss of supply from the transmission system (31%) operated by Hydro One.

While transmission system failures are largely out of the control of Algoma Power, there are investments that can be made to attempt to reduce the impacts of tree contacts, defective equipment, and even adverse weather.

Algoma Power has three service centres located in Desbarats, Wawa and Sault Ste. Marie that allow staff to respond to outages throughout the service territory.

Customer Outage Duration (Hours) by Cause 2018-2022



Online Workbook

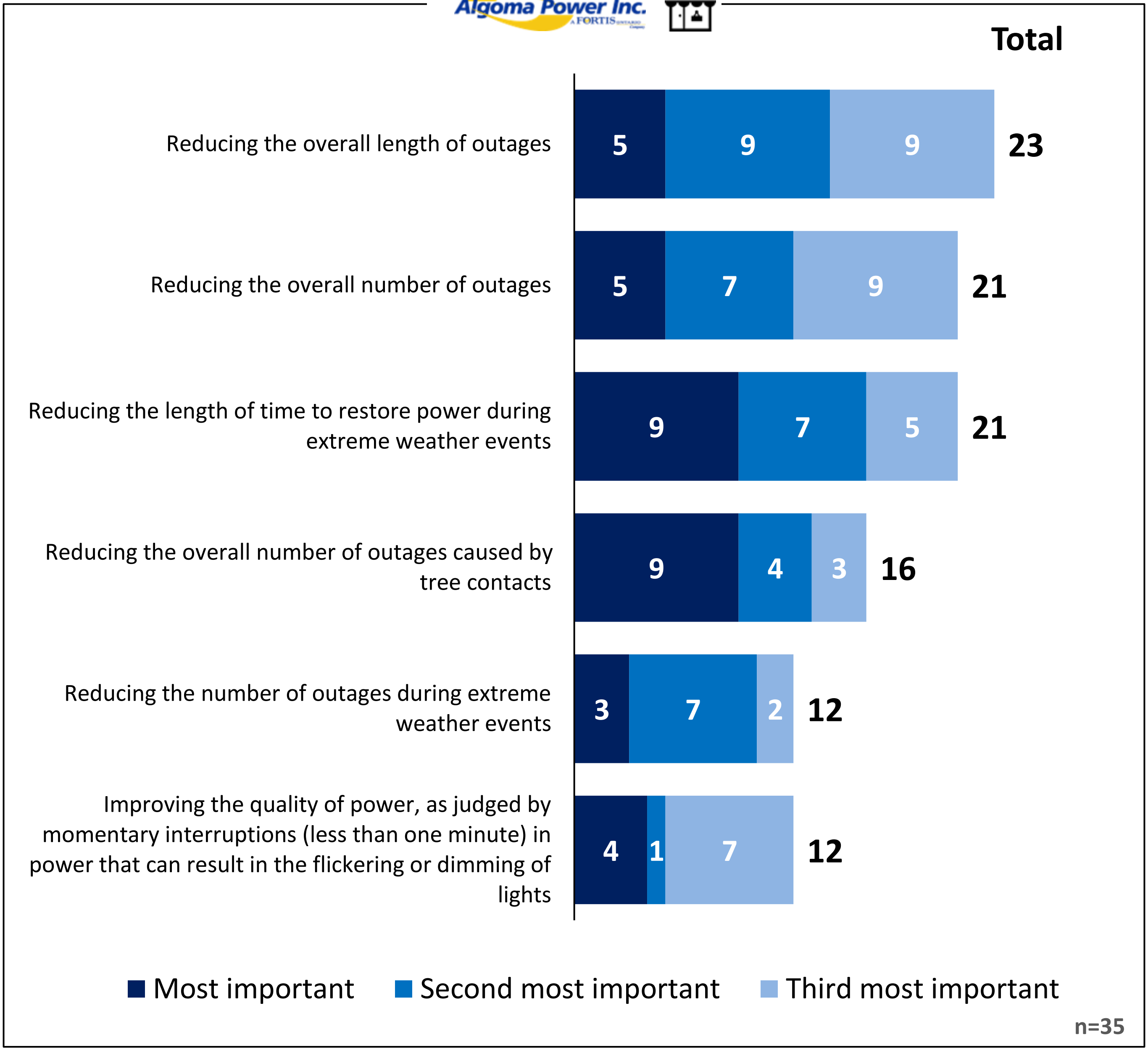
Reliability Priorities

Small Business

Q

Since reliable electricity service is so important to customers, before we move on, we want to ask you about which specific areas you feel that Algoma Power should focus on over the next five years.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, and ending with the third most important.



Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

Algoma Power Background

How does Algoma Power propose to spend your money?

As mentioned, a portion of all Algoma Power customer bills goes towards operating and maintaining the electricity system. In addition to customer rates, some provincial funding also helps fund the budget which Algoma Power uses to operate its system. Over the five-year period from 2020 to 2024, this has resulted in a 5-year budget of **$146.7 million**.

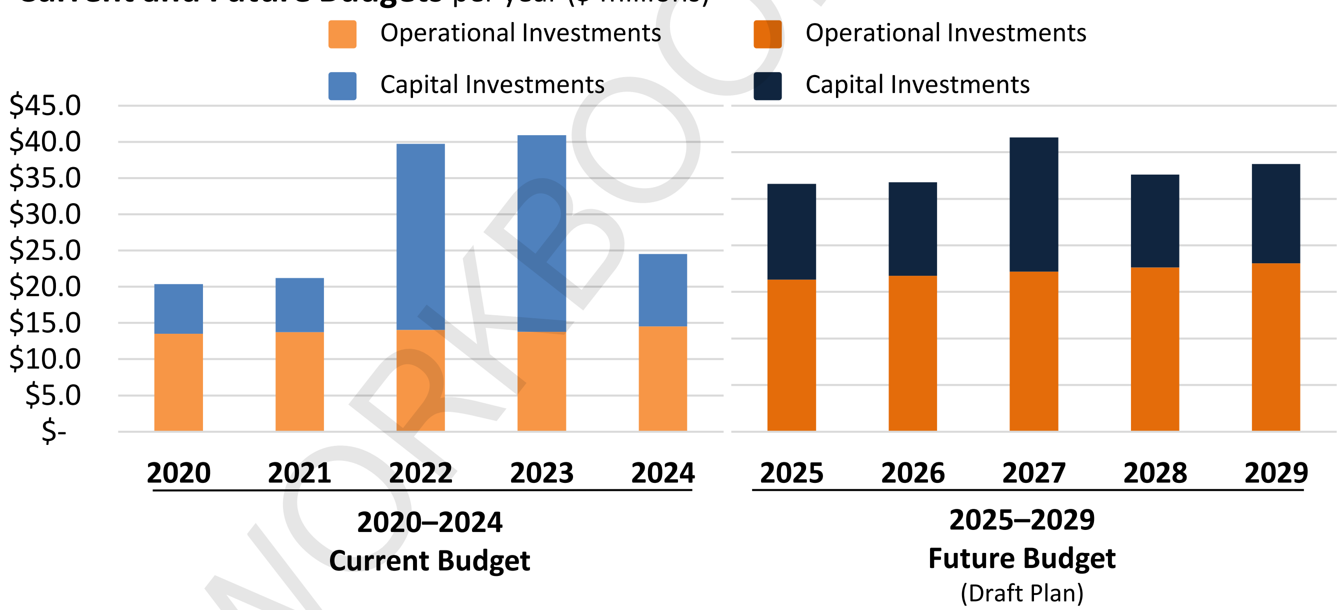
Between 2025 and 2029, Algoma Power is proposing to spend $141.3 million, a 3.7% decrease relative to the past five years.

To run the local grid and serve customers, Algoma Power manages two budgets:

1. A **capital investment** budget which pays for the cost of buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks, and computers.

2. An **operational investment** budget which pays for maintenance, testing, and operation of the equipment, vegetation management, as well as the staff needed to manage the grid and serve customers daily.

Current and Future Budgets per year ($ millions)



The current five-year budget of **$146.7 million** is based on the 2020–2024 plan approved by the OEB in a previous rate application. As mentioned earlier, this amount is funded by your 2020–2024 distribution rates.

The future five-year budget of **$141.3 million** is based on the 2025–2029 draft plan presented in this customer feedback survey. The final budget for this next rate period will be adjusted to reflect customer feedback collected through this engagement and will be subject to extensive OEB review before rates are set for 2025–2029.

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

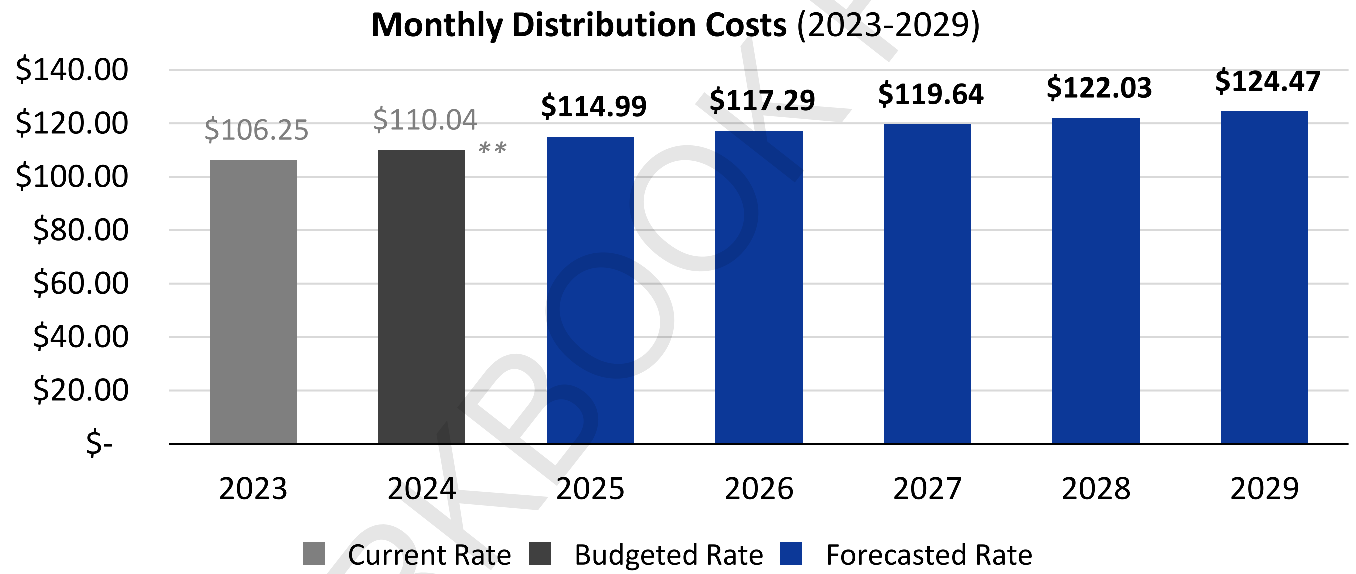
Algoma Power Background

How much will Algoma Power's draft plan cost my organization?

It is estimated that if Algoma Power continues with its draft plan, the distribution portion of the bill will be **$114.99 in 2025**, an increase of $4.95 per month compared to the budgeted **$110.04 in 2024**.

- For the period of 2025-2029, the annual bill increase is limited by the Ontario Energy Board (OEB) to an amount less than the rate of inflation with the exception of any one-time capital expenditures.
- As a result, over the 2025-2029 period, the distribution portion of the bill is forecasted to increase by an average of 2% per year.

Under this draft plan, by 2030, the typical small business customer will be paying an estimated $18.22 more on the distribution portion of their bill compared to today.



Estimates are subject to change with factors including inflation, rate design updates, and pass through cost variations. A comprehensive budget for new 2030 projects/rates has not yet been developed.

Algoma Power Background

What does Algoma Power want your feedback on?

Today, Algoma Power is seeking your input on its draft plan to ensure it is making the spending decisions that matter to you, the customer.

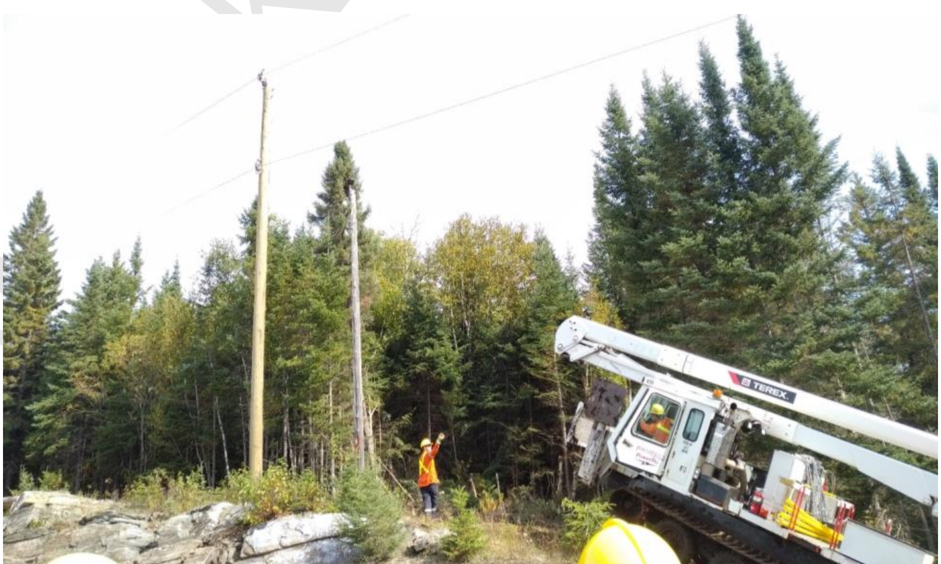
- The following sections of this workbook will explore 6 choices that Algoma Power needs to make to finalize its plans.
- Algoma Power will need to demonstrate to the OEB both what they heard from customers, as well as how they reflected your feedback in its plans.

How do I make choices?

Each choice has a summary of the options that Algoma Power is considering. In many cases, that includes options that would see Algoma Power ***spend less*** or ***more*** than what is currently being proposed.

- For each option you will be presented with to ***spend more*** or ***less***, Algoma Power has estimated what impact that would have on customer bills.
- These "rate impacts" are for illustrative purposes only. Because you are covered under **rural and distribution rate protections**, these "rate impacts" would not be reflected on your bill, but still represent the true cost of the choices.
- Following each question, you will also have an opportunity to provide additional optional feedback if you choose to.

Now, let's get started with Algoma Power's first decision related to **pole replacement**.



Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

Making Choices (1 of 6)

Pole and Line Replacement

Background: As previously mentioned, Algoma Power has one of the largest (by geography) service territories of any electricity utility in Ontario. As such, Algoma Power operates and maintains 2,108 km of distribution line that is supported by 28,931 poles.

Each year, Algoma Power identifies and prioritizes pole lines for rebuilding based on their condition, age, and the consequences of their potential failure.

A recent assessment showed that about 3% or 972 of Algoma Power's poles were deemed to be in poor or very poor condition. Meaning, while rare, these 972 poles are at increased likelihood of "failing", which would likely cause a power outage for customers supplied by the line.

Current approach: Historically, Algoma Power has proactively replaced 500 poles per year or about 2% of all the poles in the system.

This approach has resulted, in part, in the current levels of reliability that you experience today. If Algoma Power gets too far behind on proactively replacing older poles, it can result in more outages and more costly reactive repairs. One pole can serve as many as 2,000 customers or as few as one.

2025-2029 proposed approach: Each year, as Algoma Power assesses a portion of its poles, some poles that were previously deemed to be in good condition are re-classified as poor or very poor. As such, over the next five years, Algoma Power is proposing to stay on the normal course and proactively replace 500 poles per year. Replacements are always prioritized based on condition and operational effectiveness.

Algoma Power also has an option to do more or less. When less is done, it increases the chances of more outages and more costly reactive repairs, but also pushes some of the associated costs further down the road. When more is done, it can result in some minor improvements to reliability, and get ahead of the curve at an additional cost.

Online Workbook

Choice 1: Pole and Line Replacement

Small Business

Which of the following options do you prefer?

Option	Poles Replaced	Expected Outcome
Accelerated Pace ***$2.10** more on monthly bill by 2030*	Proactively replace 550 poles per year for the next five years.	• Increase the current pole replacement pace by 50 per year. • Potentially see reliability improvements due to decreased likelihood of pole failure resulting in outages. • "Get ahead" of pole replacement in subsequent years.
Current Approach *Within proposed rate increase*	Proactively replace 500 poles per year for the next five years.	• As this is the current approach, Algoma Power customers could expect to see similar reliability as it relates to poles (understanding that this is just one part of the system).
Slower Pace ***$2.10** less on monthly bill by 2030*	Proactively replace 450 poles per year for the next five years.	• Reduce the current pole replacement pace by 50 per year. • Potentially see an increased risk of failures resulting in outages. • Would reduce costs now but could result in increased costs in future years as more poles need to be replaced.

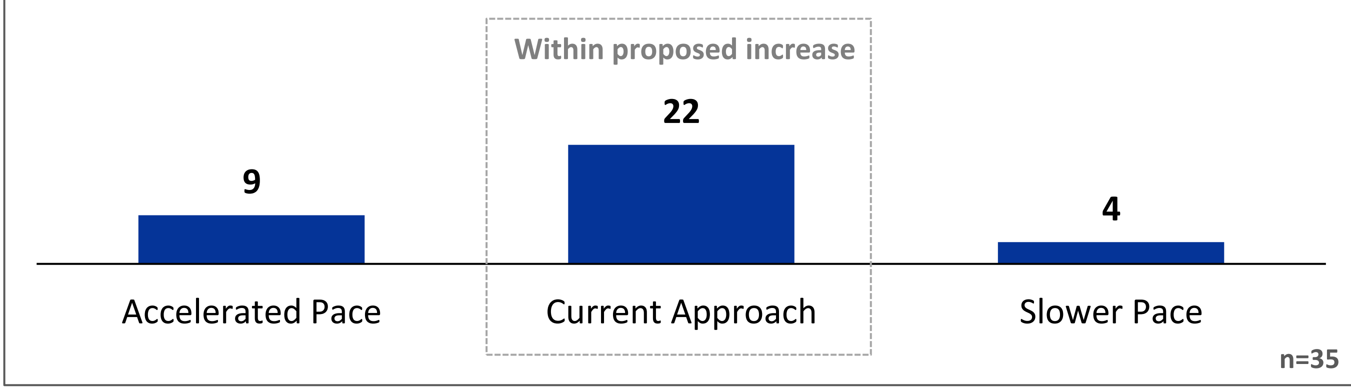
Additional Feedback (Optional)

Online Workbook

Choice 1: Pole and Line Replacement

Small Business

Q Which of the following options do you prefer?



Additional comments (optional)
"To increase life span of the poles used could composite materials be used instead of wood?"
"I know ant and wood pecker damage are not always visible so the pole checkers better decide how many need replacing"

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

Making Choices (2 of 6)

Substation Rebuild

Background: Algoma Power owns and operates 9 substations. These substations, as pictured below, are used to "step down" the voltage supplied from Hydro One prior to distribution to customers. The equipment contained within these substations is critical and has a typical useful life of 50 years. The substation pictured below is in the town of Wawa and was built more than 50 years ago. Algoma Power has historically replaced substations as their age and condition requires it, for example a project is currently underway for a substation replacement in Bruce Mines this year.

The town of Wawa, with a population of 2,705 (2021 Census) is served by two substations. If one substation were to fail, the other would be able to back it up for a period, but not as a long-term solution.

As more customers start getting electric vehicles, solar panels, or just generally continue to use more electricity as an alternative to gas and other fuel sources, Algoma Power must right-size the substation transformer capacity to accommodate these increases in electrical demand. If electricity demand exceeds the transformer capacity, this could result in higher costs in the future.

Current approach: The lead time to replace the critical equipment within a substation can be anywhere from 1 to 3 years. In this case, if one of the substations servicing the town of Wawa were to fail, the entire community could be left without backup for years.

As such, when substation equipment is assessed in poor condition, Algoma Power typically starts planning to rebuild that substation, knowing that it can take years to plan, design and construct the rebuild.

2025-2029 proposed approach: In this upcoming plan, the question is not whether this substation in the town of Wawa needs to be rebuilt, but rather if Algoma Power uses this opportunity to update the equipment to prepare for growth in the community and the associated increase in electricity demand.

The "like-for-like" replacement option would see Algoma Power installing similar equipment to what has been in place for more than 50 years. This has served customers well for many years; however, in this case, Algoma Power is proposing to upgrade the equipment to be better prepared for community growth.

Online Workbook

Choice 2: Substation Rebuild

Small Business

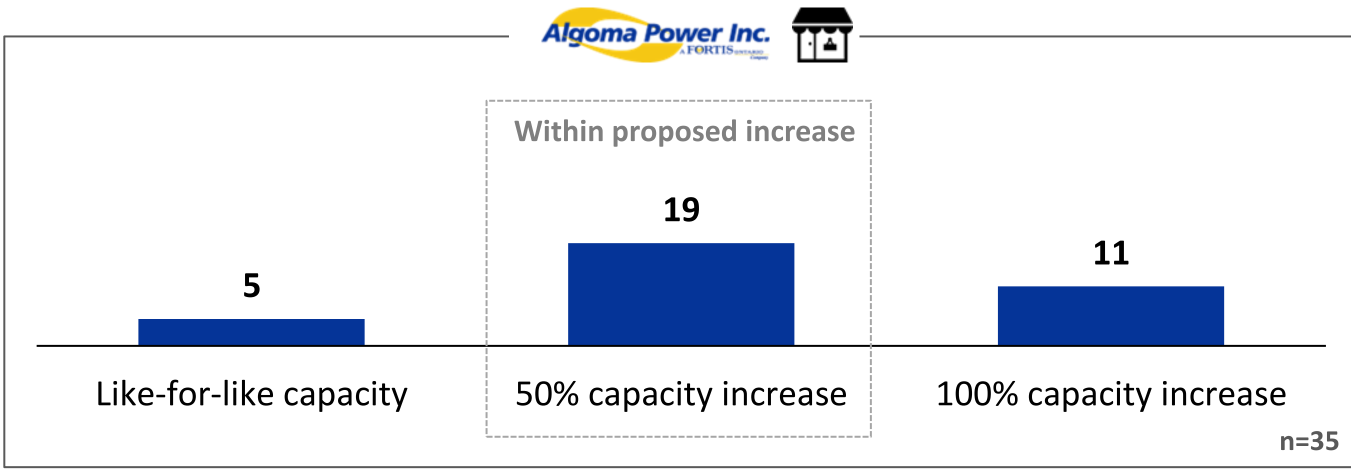
Which of the following options do you prefer?		
Option	**Transformer Size**	**Expected Outcome**
Like-for-like capacity ***$0.24** <u>less</u> on monthly bill by 2030*	Procure and install a power transformer that is similar in capacity to the existing transformer.	Increased risk of premature transformer replacement as electricity uses increases as a result of overall home and business electrification.
50% capacity increase *Within proposed rate increase*	Procure and install a power transformer with a capacity that is 50% larger than the existing transformer.	Transformer capacity is sized in accordance with projected load increases associated with overall home and business electrification.
100% capacity increase ***$0.22** <u>more</u> on monthly bill by 2030*	Procure and install a power transformer with a capacity that is 100% larger than the existing transformer.	Larger transformer capacity would support increased electricity usage beyond the projected load increases.
Additional Feedback (Optional)		

Online Workbook

Choice 2: Substation Rebuild

Small Business

Q Which of the following options do you prefer?



Additional comments (optional)
"Understanding the potential growth in the north and more mines started the increase capacity is needed."
"WAWA is a developing area of Algoma"
"More people have been moving to rural areas so increasing usage is likely"

Making Choices (3 of 6)

Voltage Conversion

Background: Much of Algoma Power's service territory is serviced by low-voltage distribution lines. These lines have much less capacity than modern lines. Meaning, that as demand for electricity increases, these lines struggle to distribute the constant flow of electricity that customers expect.

Current approach: These low-voltage distribution lines have historically served customers well, and in most cases will continue to do so. As such, upgrading these lines has not been a priority for Algoma Power in the past. However, in the future, increased demand for electricity means some of these lines are more likely to either fail or result in electricity flickering. When electricity flickers, it can result in homes and businesses having to re-set appliances or equipment, the clock on your stove, or other power quality issues. For local businesses, this can be particularly disruptive as machines and processes may be disrupted. This is more likely to occur in parts of the service territory where electricity demand increases more rapidly.

2025-2029 proposed approach: Starting in 2025, Algoma Power is proposing line upgrades to start mitigating some of the risks associated with these lower voltage lines.

Algoma Power has identified portions of the distribution system in the Goulais River and Batchawana Bay areas that serve 3,980 customers and are at risk of decreasing voltage reliability and power quality as the system load increases. To mitigate this risk, Algoma Power has proposed to convert the system voltage to a higher level.

Algoma Power is contemplating three pacing options to complete the voltage conversion in the Goulais River and Batchawana Bay areas - a minimum-level, mid-level and full-level voltage conversion plan. What isn't completed in this upcoming 5-year period will need to be completed in the next cycle. Doing more in the next 5-years will reduce the risk of equipment failure and power quality issues but increase the price you pay over this period. While the question requests your feedback on a project in a specific area, Algoma Power will take your feedback into account when looking at voltage conversion in other areas of the system.

Online Workbook

Choice 3: Voltage Conversion

Small Business

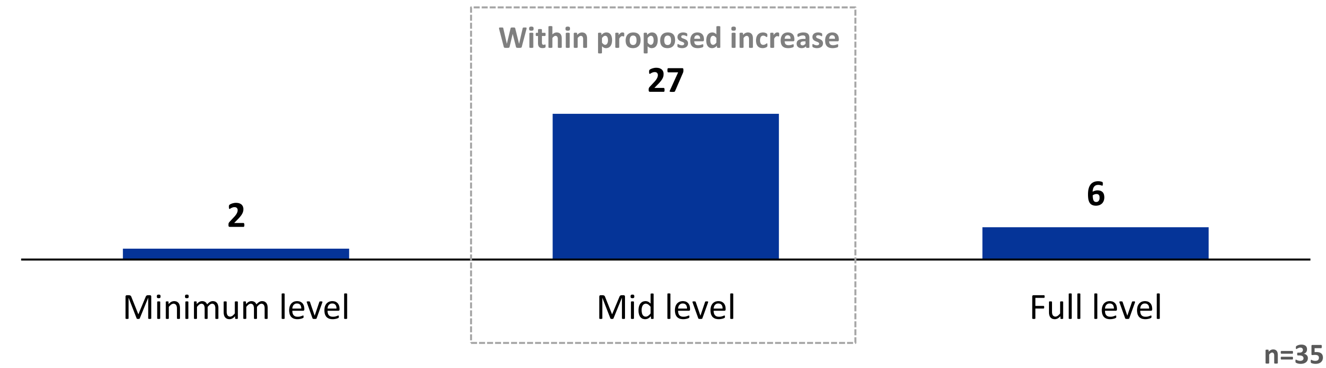
Which of the following options do you prefer?		
Option	% Upgraded	Expected Outcome
Minimum Level ***$0.17** less on monthly bill by 2030*	Upgrade and convert approximately 25% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 995 customers. • Lower cost now, but more will need to be deferred to the next cycle.
Mid Level *Within proposed rate increase*	Upgrade and convert approximately 50% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 1,990 customers. • Lower cost now, but some will need to be deferred to the next cycle.
Full Level ***$1.77** more on monthly bill by 2030*	Upgrade and convert approximately 100% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 3,980 customers. • Higher cost now, but none will need to be deferred to the next cycle.
Additional Feedback (Optional)		

Online Workbook

Choice 3: Voltage Conversion

Small Business

Q Which of the following options do you prefer?



Additional comments (optional)
“Understanding that the region to be worked on is not easy terrain is it more beneficial to start doing underground powerlines vs towers? Would this also not decrease the weather related outages?”
“Business needs being met, not for 2nd, third luxury single dwellings.”

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

Preparing for increased electricity demand

Background: Transformers are a critical piece of equipment that reduces the voltage of electricity before it enters your home or business. These transformers 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. That means a business using lots of electricity will generally have a larger transformer serving it than a typical 2- or 3-bedroom home.

But today, the "smaller" transformers that have historically served Seasonal homes are increasingly struggling to keep up with increased demand. That means, today, when a transformer fails, it's replaced with a "larger" one to accommodate the increased demand for electricity.

Current approach: Currently, as is the case with most electricity utilities in Ontario, Algoma Power operates its transformers until they fail. When a transformer does fail, it typically takes between 2 and 4 hours to replace it and get the power back on for the customers that it serves.

However, as more customers start getting electric vehicles, solar panels, or just generally continue to use more electricity as an alternative to gas and other fuel sources, Algoma Power is projecting that more and more transformers will need to be upgraded to accommodate these changes. If demand increases quicker than Algoma Power can upgrade transformers, this could lead to transformers failing more frequently.

2025-2029 proposed approach : Over the next five years, Algoma Power is proposing a similar approach to what has been done in the past. That is, run the transformers until they fail and replace them with "larger" transformers to accommodate increased electricity usage.

However, depending on what customers value, Algoma Power is considering a new program that would identify areas in the community with the greatest increase in demand, and proactively swapping out the smaller transformers for larger ones to avoid potential failures. This new program wouldn't have a significant impact on current reliability but would help ensure that when the time comes, customers will have access to the electricity they want to meet their growing and changing needs.

If demand for electricity from customers increases more rapidly than expected, Algoma Power may have to cancel or delay other planned projects to accommodate these newer transformers that aren't budgeted for.

Online Workbook

Small Business

Choice 4: Preparing for increased electricity demand

Which of the following options do you prefer?

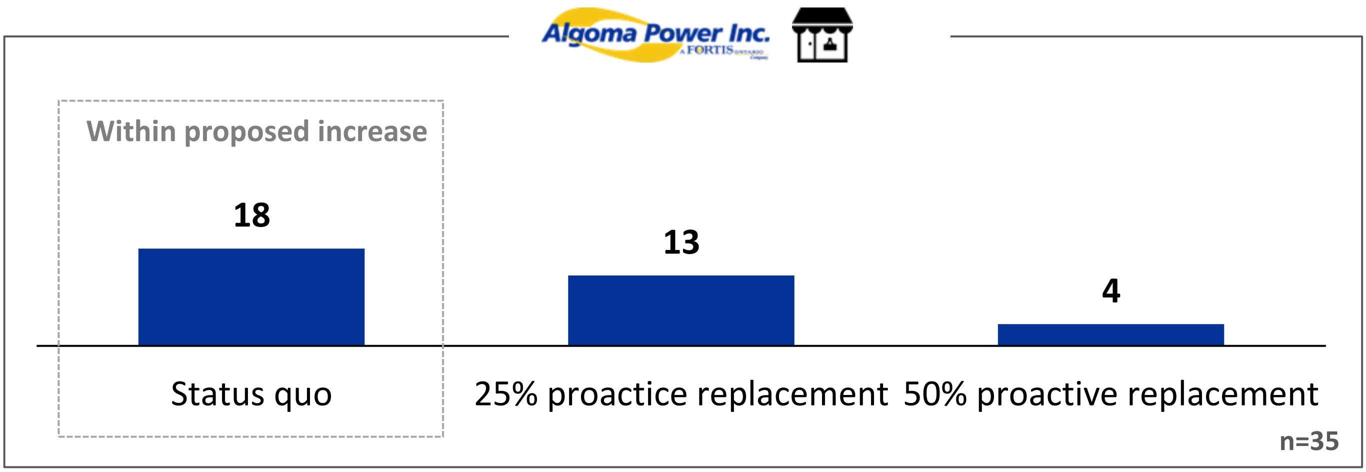
Option	Transformers Replaced	Expected Outcome
Status Quo *Within proposed rate increase*	Based on historical data, reactively replace approximately 12 transformers per year as they fail.	• Maximize the useful life of current transformers. • Potential for higher levels of unplanned outages due to transformer failures.
25% proactive replacement ***$1.06** <u>more</u> on monthly bill by 2030*	Proactively replace 275 transformers by 2029 (55 per year).	• Accelerate transformer changes to meet anticipated demand for electricity. • Potential for reduced rate of unplanned outages due to transformer failures.
50% proactive replacement ***$2.13** <u>more</u> on monthly bill by 2030*	Proactively replace 550 transformers by 2029 (110 per year).	• Further accelerate transformer changes to meet anticipated demand for electricity. • Potential for reduced rate of unplanned outages due to transformer failures.
Additional Feedback (Optional)		

Online Workbook

Small Business

Choice 4: Preparing for increased electricity demand

Q Which of the following options do you prefer?



Additional comments (optional)
"how does the use of solar panels create and increase on the current grid? do they not decrease the homeowner's reliance on the power grid there by decreasing stress on the system?"
"If it ain't broke, don't fix it? "Maximize the useful life"..powerful words to live by. See previous response also. Educate about electricity…scarey and amazing."

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

Making Choices (5 of 6)

Automated "intelligent" switches

Background: Technology has changed the way that Algoma Power can manage and monitor the distribution system.

Strategically located automated switches can help Algoma Power remotely monitor and trace power outages and re-route electricity from a control room rather than sending a repair crew to patrol the lines. This is made possible by both a) a physical automated "switch" often mounted on a pole that allows Algoma Power to easily locate an outage and b) computer software that allows that automated "switch" to be flipped remotely and re-route power.

Current Approach: Currently, Algoma Power has strategically employed "intelligent" automated switches in various parts of its service territory. When an outage occurs in an area without this automated technology, it can take crews between 4 and 8 hours to locate the issue, fix it and restore power.

By installing only an automated switch in an area, outage restoration times can be reduced by nearly half.

When an automated switch and the accompanying software is installed, an outage that would otherwise take 4-8 hours to restore could be reduced to less than one hour.

As with anything, there are costs associated with rolling out this technology more broadly.

2025-2029 proposed approach: In its current draft plan, Algoma Power is proposing to roll out the installation of automated switches and the associated software along a major line that serves approximately 6,200 customers east of Sault Ste. Marie.

That said, depending on customer feedback, Algoma Power could continue with the status quo and install no new additional switches, or they could defer some of the software upgrades to a later period, therefore reducing the bill impact for customers.

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Choice 5: Automated "intelligent" switches

Which of the following options do you prefer?		
Option	Automated Switches	Expected Outcome
Status Quo ***$0.94*** *<u>less</u> on monthly bill by 2030*	No additional automated switches or software purchased and installed.	Across this stretch of the system, Algoma Power continues to manually locate outages and restore power, typically taking between 4 and 8 hours on average.
Partial Implementation ***$0.46*** *<u>less</u> on monthly bill by 2030*	• Install remotely controllable automated switches on a major line east of Sault Ste. Marie that serves 6,200 customers. • Defer the purchase and installation of software to 2030 and beyond.	Across this stretch of line, Algoma Power will be able to remotely locate an outage, improving average estimated restoration times by about 50%.
Full Implementation *Within proposed rate increase*	• Install both the remotely controllable automated switches and associated software on the major line east of Sault Ste. Marie. • Once software has been installed once, it can be rolled out across the system in the future.	Same benefits of partial implementation, however, outage restoration times are reduced even further because power can be restored remotely.
Additional Feedback (Optional)		

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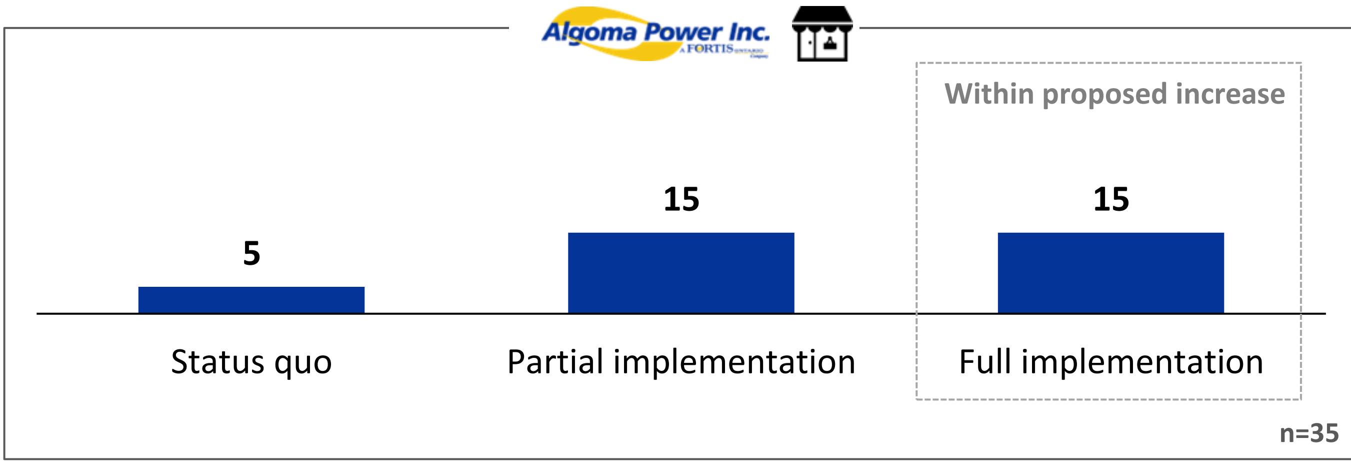
Choice 5: Automated "intelligent" switches

Small Business

Q Which of the following options do you prefer?



Additional comments (optional)

"Software shelf life? Who doesn't need a little power outage occasionally…you don't know what you got till it's gone ??"

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Planning for the Future: 2025-2029 Rate Application

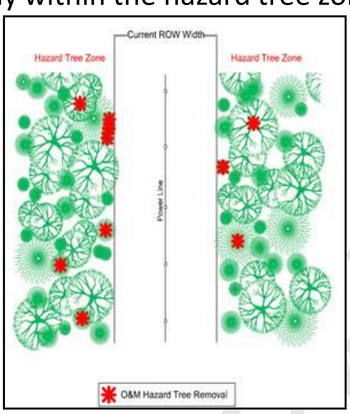
Making Choices (6 of 6)

Vegetation Management

Background: Between 2018 and 2022, tree contacts have contributed to 35% of all customer outages, as measured by the total number of hours without power. While tree caused outages have significantly declined over the years through Algoma Power's Vegetation Management Program (VMP), trees remain the biggest contributor to customer power outages. As 85% of Algoma Power's powerlines have a treed (forested) edge, the most common cause of power interruptions are tree related and require crews to be dispatched to make repairs and restore power.

Current approach: Algoma Power continues to manage vegetation in proximity to powerlines to reduce the risk of tree exposure and limit the occurrence of tree caused outages. Work activities including trimming and removal of trees are part of scheduled maintenance practices used to manage vegetation (trees and brush) that can fall or grow into the powerlines.

To mitigate these risks, Algoma Power's VMP takes a preventative approach using condition assessments to determine priority work. Priority work is largely based on tree health, growth, and impact to service interruptions. To date, priority work is a main contributor to the reduction in tree caused outages, particularly within the hazard tree zone (see diagram below).



2025-2029 proposed approach: In its current draft plan, Algoma Power is proposing to continue with its historical approach of preventative maintenance to reduce the potential of tree caused outages across the service territory. While this would result in similar reliability outcomes to the past, the rapid improvements to reliability would likely slow down.

To further reduce costs, Algoma Power is also considering reducing the frequency of assessing and removing declining trees that occurs within this "hazard tree zone". Reducing this assessment would ultimately increase the risk that a tree in poor condition is missed and could therefore come into contact with a powerline.

On the other hand, Algoma Power could also increase its assessment in this area, further reducing the likelihood of a tree contact, even relative to today's standards. This is where Algoma Power wants to hear from you.

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Choice 6: Vegetation Management

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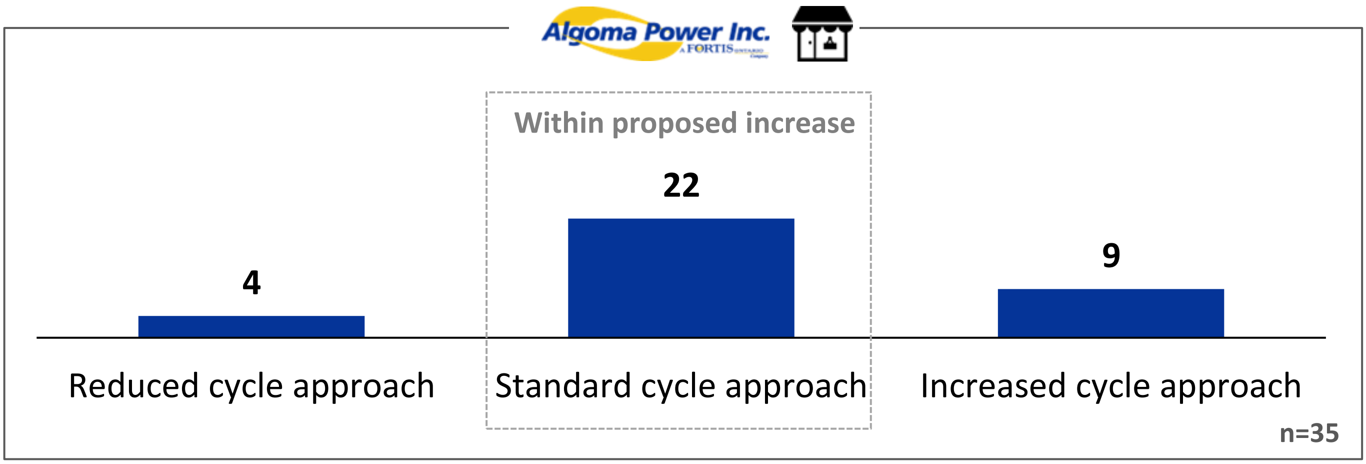
Which of the following options do you prefer?		
Option	Approach	Expected Outcome
Reduced Cycle Approach ***$1.98*** *less on monthly bill by 2030*	Reduce the level of "hazard tree zone" monitoring by 300 km per year.	• Increased exposure of hazard trees to the powerlines • Potential for decreased reliability resulting from increased exposure of the hazard trees.
Standard Cycle Approach *Within proposed rate increase*	Status Quo, continue with historical approach.	• Similar trend in reliability performance relative to the past 5 years
Increased Cycle Approach ***$1.98*** *more on monthly bill by 2030*	Increase the level of "hazard tree zone" monitoring by 300 km per year.	• Decreased exposure of hazard trees to the powerlines • Potential for increased reliability performance resulting from reduced exposure of the hazard trees.
Additional Feedback (Optional)		

Online Workbook

Choice 6: Vegetation Management

Small Business

Q Which of the following options do you prefer?



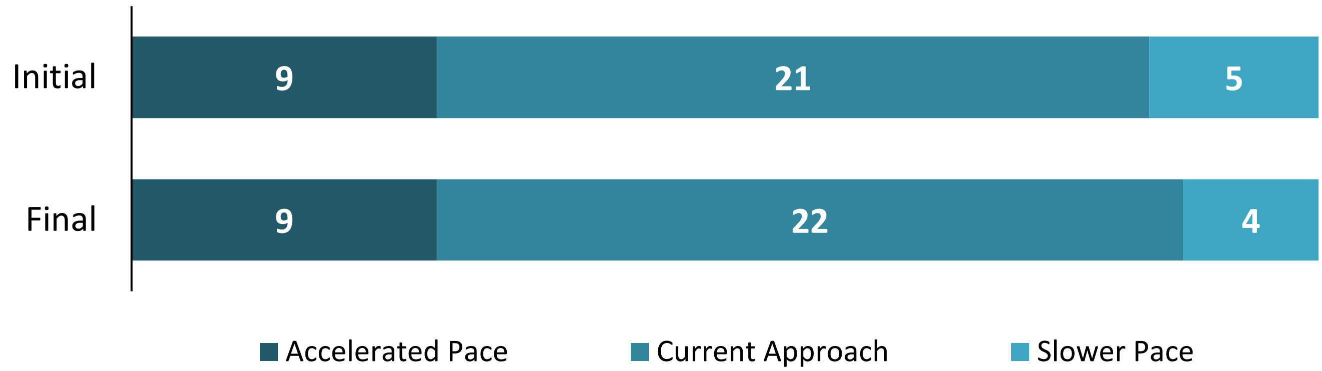
Additional comments (optional)
"I think the last few years the power supply has been good and there will always be some tree problems"
"This one strikes a nerve...am still not over losing a century old cedar tree to the "vegetation management" of Algoma power. It was not a threat to any line in its 100+ years and was not about to sprout up and become one. Same goes for apple trees that homeowner was assured would not be chopped down, only to find out the right hand didn't know what the left hand was doing. Gone. Also, not sure if tree hazard and extreme weather can be separated at this stage of the game. Which came first the chicken or the egg?"

Making Choices

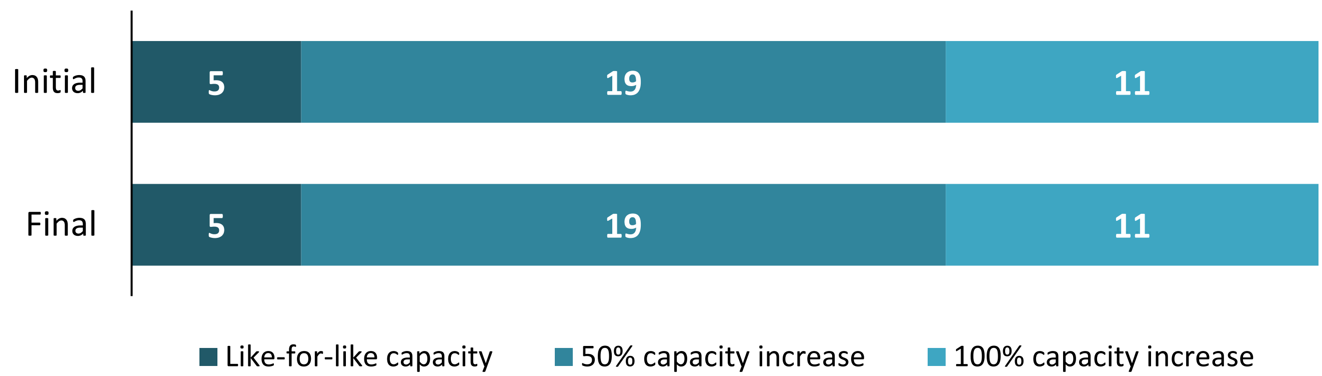
Impact of Choices

Small Business

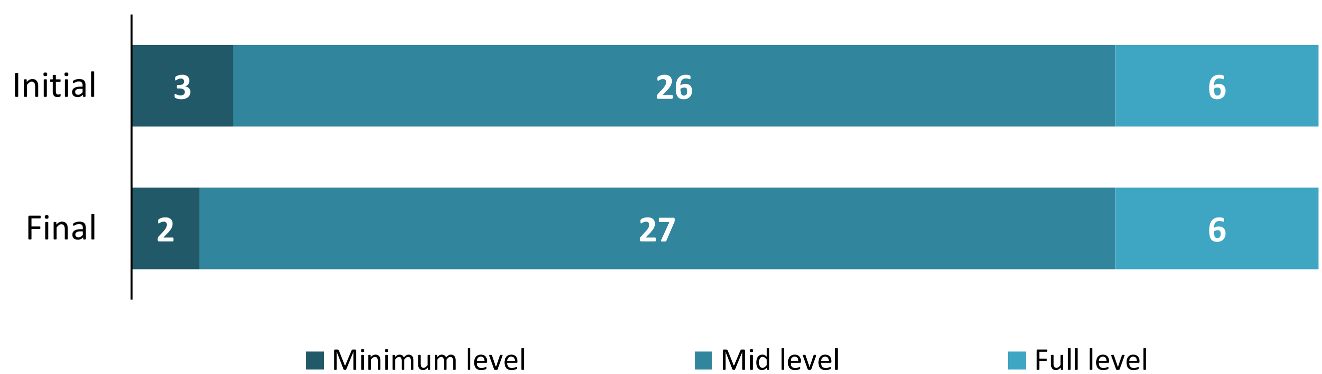
Pole and Line Replacement



Substation Rebuild



Voltage Conversion



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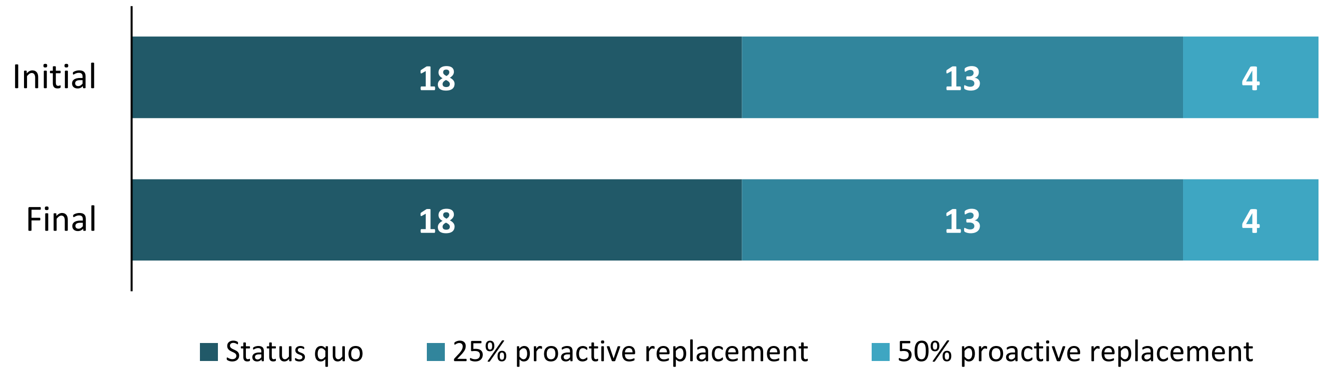
Making Choices

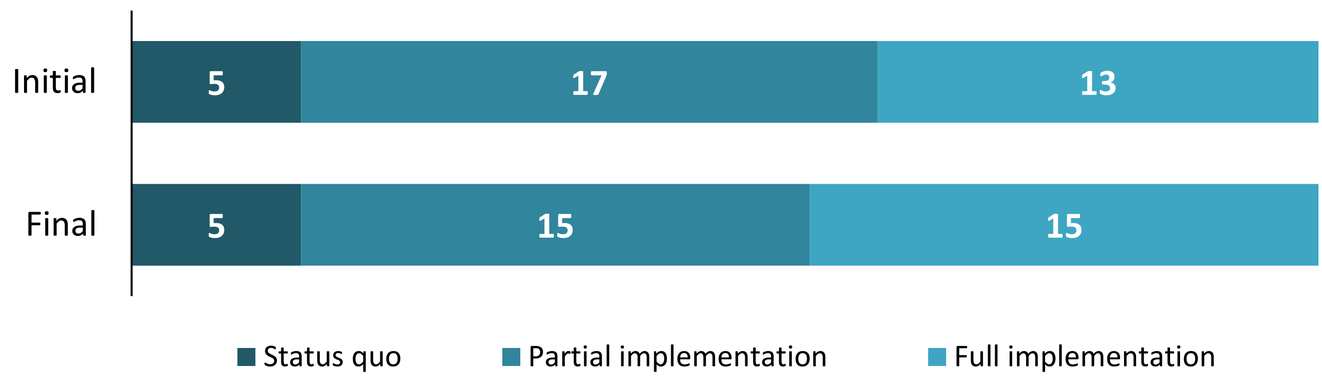
Impact of Choices

Small Business

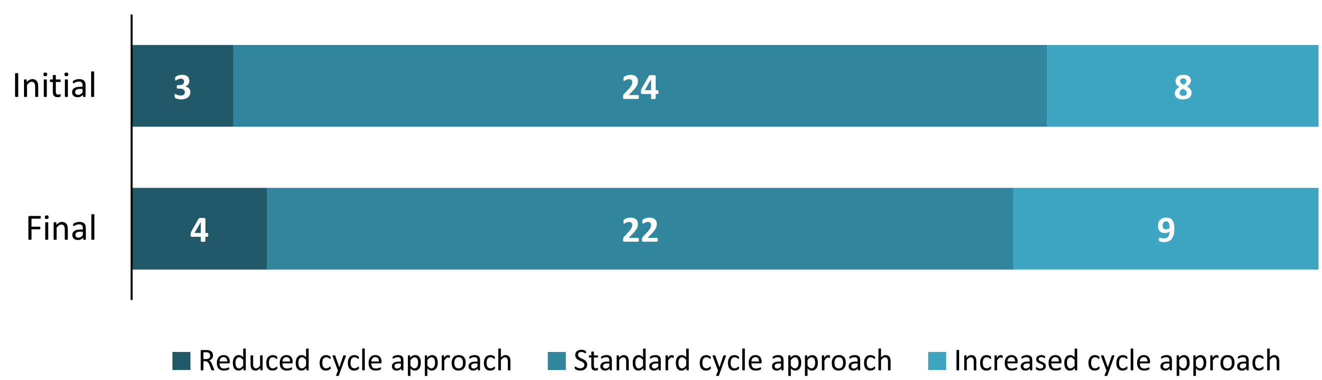
Preparing for increased electricity demand



Automated “intelligent” switches



Vegetation Management



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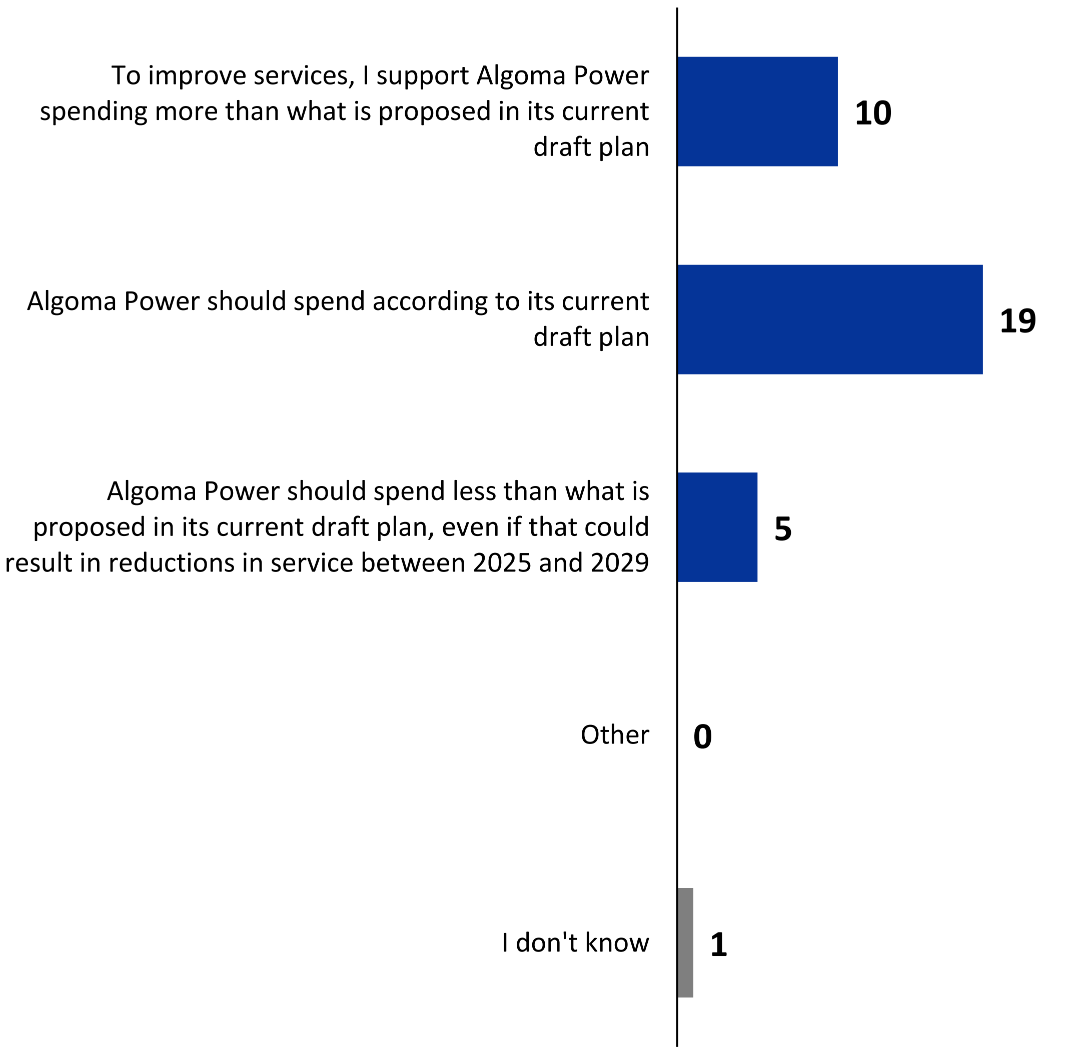
Overall Plan Evaluation

Small Business

Q

Algoma Power has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Algoma Power would like to know how you feel about the draft plan.

Considering what you have learned about Algoma Power's 2025–2029 draft plan, which of the following best represents your point of view?



n=35

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Small Business Customers

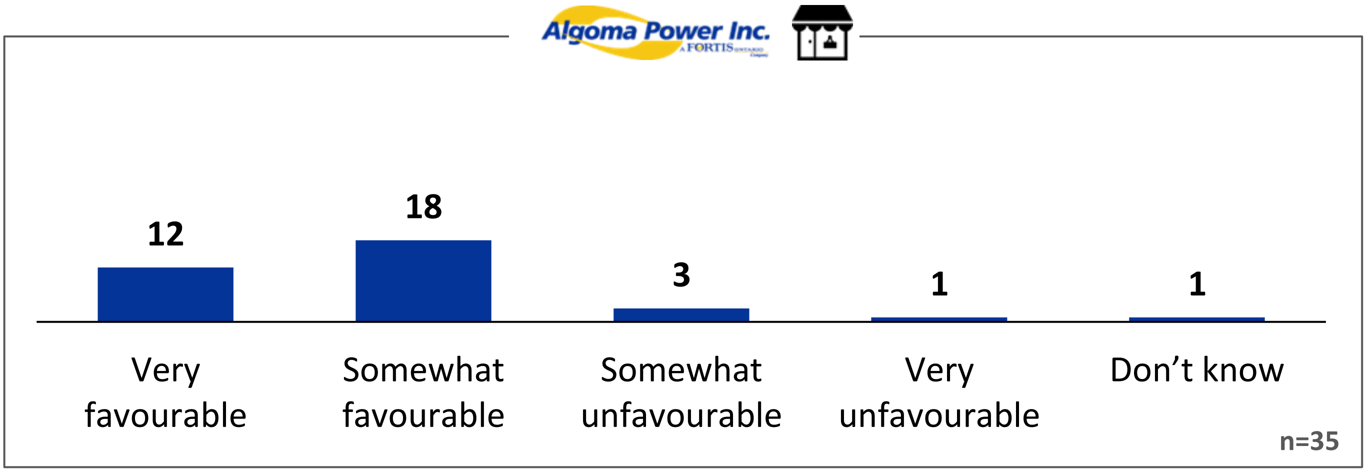
Workbook Diagnostics

Online Workbook

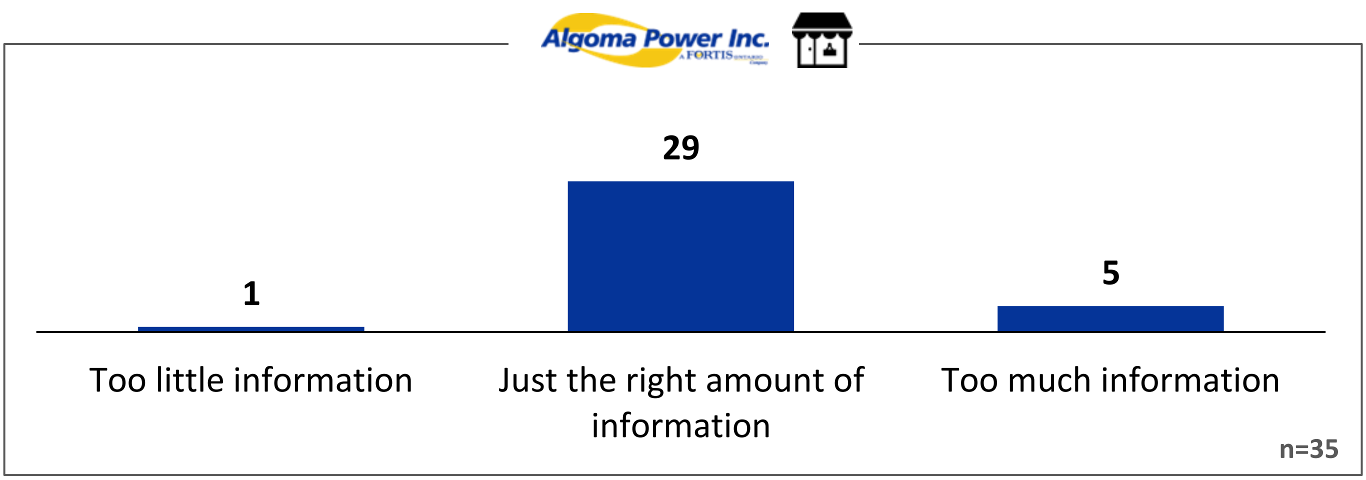
Workbook Diagnostics

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 Algoma Power provided too much information, not enough, or just the right amount?



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Content Missing from Engagement

Small Business

Q Was there any content missing that you would have liked to have seen included in this customer engagement?

Verbatim responses (optional)
"I understand that to make improvements you need to spend more money; my issue is that every time more money is asked for, the profit margins of the company go up as do the salaries of the CEO's. Why can some of the money not come from there? The customers you serve are not making that much and their income is not increasing at the rate of profits and CEO's"
"reduce-delivery-costs"
"Your pricing is to much for all of us"
"I would hope between your engineers and technicians that develop these plans it is likely very close to what is needed"

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Appendix

Large Business Customers Results Summary

Online Workbook

Large Business Customers Results Summary

Summary Results: Familiarity and Satisfaction

Question	Response	Large Business [n=7]
Before this survey, how familiar would you say you were with Algoma Power and the role it plays in Ontario's electricity system?	Very familiar	3
	Somewhat familiar	3
	Not familiar at all	1
	Don't know	-
Thinking specifically about the service provided to you and your community by Algoma Power, overall, how satisfied or dissatisfied are you with the services that you receive?	Very satisfied	3
	Somewhat satisfied	2
	Neither satisfied nor dissatisfied	-
	Somewhat dissatisfied	1
	Very dissatisfied	1
	Don't know	-
Before this survey, how familiar were you with the amount of your electricity bill that went to Algoma Power?	Very familiar	3
	Somewhat familiar	2
	Not familiar	2
	Don't know	-
Before this survey, how familiar were you with this government program which applies to rural Algoma Power customers and caps the among of distribution charges your organization pays?	Very familiar	3
	Somewhat familiar	2
	Not familiar	2
	Don't know	-

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Large Business Customers Results Summary

Summary Results: Setting Priorities

Question	Response	Large Business [n=7]
Setting priorities within Algoma Power's Plans. [Number of customers who select the priority in their top three]	Delivering electricity at reasonable rates	5
	Ensuring reliable electrical service	3
	Investing in new technology to help reduce costs	2
	Investments to better withstand adverse weather	-
	Replacing aging infrastructure	2
	Providing quality customer service	3
	Helping customers with conservation/cost savings	1
	Minimizing API's impact on the environment	1
	Ensuring the safety of electricity infrastructure	4
	Enabling customers to access new electricity services	-
Have you experienced any outages as an Algoma Power customer in the past 12 months which lasted longer than one minute?	No outages	-
	1-2 outages	3
	3-4 outages	1
	5-6 outages	-
	7-8 outages	-
	9-10 outages	-
	11 or more outages	-
	Don't know	3
Focus on reliability priorities. [Number of customers who select the priority in their top three]	Reducing the overall number of outages	5
	Reducing the overall length of outages	7
	Reducing number of outages during extreme weather	1
	Reducing length of time to restore power during extreme weather	2
	Improving the quality of power	5
	Reducing number of outages due to tree contacts	1

Online Workbook

Large Business Customers Results Summary

Summary Results: Environmental Controls and Electrification

Question	Response	Large Business [n=7]
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.	Strongly agree	1
	Somewhat agree	6
	Somewhat disagree	-
	Strongly disagree	-
	Don't know/No opinion	-
Customers are well served by the electricity system in Ontario.	Strongly agree	2
	Somewhat agree	4
	Somewhat disagree	1
	Strongly disagree	-
	Don't know/No opinion	-
Does your organization have a formal electrification strategy in place? Meaning, a strategy to shift from fossil fuels – such as oil, natural gas, and coal – to electricity produced from non-carbon emitting sources.	Yes	-
	No, but we are in the process of developing one	-
	No, but we anticipate developing one in the future	2
	No, and we don't anticipate developing one in the future	3
	Don't know	2
Is your organization planning to install electric vehicle charging stations for public use within the next 5 years?	Yes	1
	No	5
	Don't know	1

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For more information, please contact:

Julian Garas
Vice President
416-640-4133
jgaras@innovativeresearch.ca

Vanna McDonald
Director
236-335-4732
vmcdonald@innovativeresearch.ca

Report Contributors:

Martha Villarreal Lopez, Consultant

Carmen Hui, Research Analyst

Attachment 1J

Project Responsiveness to Objectives

Algoma Power Inc.
EB-2024-0007

	Worker and Public Safety, Environmental Protection, Cybersecurity	Sustaining End of Life Asset Replacement	Sustaining Vegetation Management	Reliability and Resilience improvements	General Plant Investments to Support Productivity and Efficiency	A cost-effective, long term approach to energy transition	Customer/Stakeholder Preferences	Cost Effectiveness
Service Connections	•work is completed within O.Reg 22/04 requirements •coordination with nearby asset replacement to reduces mobilization and emissions	•service connections reviewed for possibility of required nearby asset replacement to minimize mobilization costs.	Sustaining VM allows API to complete Service Connection work efficiently.	N/A	General Plant investments allow API to complete Service connection work efficiently.	Where grid constraint is identfied, NWS will be considered to facilitate connection.	Service connections are completed in response to customer requests	Work is completed in coordination with other requirements, where possible, to minimize mobilization costs.
Small Lines/Stations Capital	•Proactive replacement approach is safer than reactive replacement. •Proactive replacement can avoid/minimize oil leak risks. •work is completed within O.Reg 22/04 requirements	•Projects identified based on inspection results-failure/performance risk of each asset.	Sustaining VM allows API to complete Small Lines/Stations replacement work efficiently.	•Replacing deteriorated assets prior to failure allows API to reduce or eliminate the outage impact of an unplanned outage.	General Plant investments allow API to complete Small Lines/Stations replacement work efficiently.	N/A	•Proactive approach minimizes outage duration, frequency •Proactive approach minimizes replacement costs	Proactive replacement can be associated with lower costs, ex: due to planned work during regular hours.
Smart Meter Replacement	•Program will be conducted in line with all applicable health and safety requirements •Newer smart metering assets will improve risk mitigation against Cyber Security threats.	Program supports the replacement of Smart Meters and associated infrastructure reaching end of life.	N/A	API's smart metering network supports its outage identification and management.	General Plan investments support API's imlementation of the SM replacement program.	N/A	•Proactive replacement enables billing accuracy. •Program aims to avoid cost premiums for reactive replacements and stabilize costs over time.	•Proactive replacement approach promotes cost-effective replacements. •API's long-term goal is to create a chronologically diverse reverification batch size that stabilizes annual costs •Proactive approach allows API to optimize use of internal resources.
Wawa #2 DS	Rebuild will mitigate existing oil containment risks and improve working clearance and associated worker safety.	Wawa #2 DS is one of API's oldest stations, assessed as fair-poor condition. Transformer is in poor condition.	N/A	•Aged transformer presents reliability risk; failure would leave Wawa without backup. •Current station design requires total de-energization of the station for switching or equipment failures.	General Plant investments such as SCADA will enable future efficiencies in the use and operation of the DS.	The incremental costs for a 50% transformer capacity increase are nearly immaterial today, but could avoid costly replacements and upgrades in the long term.	•API's proposal is consistent with customer feedback on this project •Project supports cost-effectiveness and reliability improvements.	•"Right Sizing" today will help avoid costly upgrades in the future to address load growth. •New station design will allow API to operate the DS in a more cost-efficient manner.
Goulais TS Refurbishment & Voltage Conversion	•Goulais TS refurbishment will improve overall worker safety and safe working clearances. •Voltage conversion will eliminate API's requirement for a 12.5/25kV autotransformer and associated foundations and switching equipment.	TS Refurbishment is a result of HOSSM's end-of-life asset replacement program.	API's VM Program will support the efficient completion of Voltage Conversion work	Investment will support improved voltage reliability and stability	General Plant investments support API's ability to complete the Voltage Conversion project work.	•HOSSM will upgrade the supply at Goulais TS to 25kV (above like-for-like), which will accommodate long term growth forecasts. •Investments will enable more DER connections and EV charging infrastructure.	•API's proposal is consistent with customer feedback on this project •Investment supports reliability, power quality, connection of new customers, and cost-effectiveness	•API has chosen a balanced approach, the "medium" scenario of voltage conversion. •The voltage conversion plan will result in avoided costs for dual-voltage HOSSM transformer, and API owned station. •Investments in Goulais TS will limit future investments due to long term growth.
Distribution and Subtransmission Line Rebuilds	•Program designed to avoid unplanned outages, which can pose significant worker and public safety risk. •Proactive replacement of poles, wires and hardware ensures that API's is progressively being brought up to current and safe standards. •Each project is thoroughly reviewed to identify any issues related to the natural environment or areas of cultural significance. •Subtransmission pole replacement avoid costlier reactive replacements and reduce reduce wildfire risk.	•Avg. Replacment of 500 poles per year designed to ensure long term stability of pole replacement program.	Sustaining VM Allows API to complete line rebuilds efficiently.	• Reliability and resilience are supported through replacement of older, deteriorated assets with new assets, which inherently are less likely to fail. •Proactive asset replacement minimizes outage impact and duration as unplanned outages can take significantly longer to restore. •Reliability and resilience are further supported through the updating of assets to today's higher standards.	General Plant investments permit API to complete its Line Rebuilds programs efficiently	N/A	•Proactive approach minimizes outage duration, frequency •Proactive approach minimizes replacement costs •Lifespan optimization reduces risk of early writeoffs •Updating assets to today's standard supports resiliency and reliability •Customers supported API's proposed replacement pace in Customer Survey (vs. 10% increase or decrease).	•Proactive approach minimizes replacement costs •Lifespan optimization reduces risk of early writeoffs. •Lifespan optimization supports long-term program cost stability and avoids higher future costs. •Planned approach allows API to optimize use of internal resources. •Planned, proactive approach allows API to minimize costly "one-off" replacements. •Planned proactive approach has been historically successful at avoiding unplanned pole failures, which can be significantly more costly to address.
Protection, Automation, Reliability	•Work will be conducted in line with all applicable safety, cybersecurity and environmental policies and requirements. •Investments that reduce future unplanned outages inherently support improved safety. •Reliability improvements resulting in a reduction of outage frequency would reduce the emissions associated with vehicles responding to after-hours outage events	Where applicable, API will combined Protection, Automation and Reliability work with replacement work due to asset age/condition.	Sustaining VM allows API to complete its Protection, Automation and Reliability programs efficiently.	Projects have been selected to address the highest opportunities for reliability improvements.	General Plant investments permit API to complete its Protection, Automation, Reliability programs efficiently	•Many projects have a positive impact on power quality and accommodation of REG/DER projects. •Projects involving distribution automation enable API to connect more DERs employ DERs as Non Wires Solutions for future distribution needs.	API consulted with customers specifically on the Distribution Automation component of this Program. API's proposal is in line with customer preference, which supported "full implementation"	•Many projects will have a positive impact on system losses and enable future cost savings. •Incorporation of advanced SCADA-capable equipment will support operational and asset management efficiences.
Vegetation Management	•Vegetation management work is conducted within applicable safety and environmental requirements • proactive VM work enhances worker and public safety. •API's processes are conducted in line with wildfire mitigation requirements	VM Allows API to complete its asset replacement programs efficiently.	API's Vegetation Management program enables API to keep vegetation near powerlines under adequate control, mitigating the impact of unplanned outages and allowing API efficient access to maintain and operate its distribution assets.	•VM program has contributed to steady improvements in the number and duration of outages. •Tree caused outages will continue to be the #1 outage source in API's territory •VM activities help avoid outages during some extreme weather events, and enable crews to restore power when outages do occur. •VM practices are designed to mitigate Wildfire risks.	General Plant investments support API's VMP.	N/A	•API's proposed approach to Hazard Tree Removal is consistent with direct customer feedback. •API conducts significant VM customer engagement. When landowners decline permission to apply herbicide, API complies. •Program supports cost efficiency and outage reductions as outlines in surrounding sections.	•API's VMP is designed with optimal cycle durations that ensure control is maximized, avoiding long term cost increases. •Despite increasing challenges as a result of reduced ability to apply herbicide as well as inflationary increases, API has incorporated cost efficiency targets into its 2025 budget based on improved herbicide use and application of mechanical clearing.